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
AEP Texas	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 AEP Texas		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 Riversise Plaza, Columbus, OH 43215-2373		
05 Name of Contact Person Jason M Johnson		06 Title of Contact Person Accountant
07 Address of Contact Person (Street, City, State, Zip Code) 1 Riversise Plaza, Columbus, OH 43215-2373		
08 Telephone of Contact Person, Including Area Code 614-716-1000	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/09/2024
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Jeffrey W.Hoersdig 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: AEP Texas	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)
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	N/A
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	N/A
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	N/A
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	N/A
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		

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Name of Respondent: AEP Texas	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

212 East 6th Street, Tulsa, Oklahoma 740119

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

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

AEP Texas is a public utility engaged in the purchase, sale, transmission and distribution of electricity in the State of Texas. Under the Texas electric restructuring legislation, we completed the final stage of exiting the generation business and have ceased serving retail load. AEP Texas' remaining generating capacity that is not deactivated has been transferred to an affiliated company at our cost pursuant to a 20-year agreement.

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: AEP Texas	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.

In 2016, AEP Utilities, Inc. (formerly Central and South West Corporation, a registered holding company) owned 100% of the outstanding shares of common stock of both AEP Texas Central Company and AEP Texas North Company. On December 31, 2016, those companies merged into AEP Utilities, Inc., and AEP Utilities, Inc. name was changed to AEP Texas. American Electric Power Company, Inc., a registered holding company, owned 100% of AEP Utilities, Inc.'s outstanding shares of common stock during 2016 and owns 100% of AEP Texas outstanding common stock.

Name of Respondent: AEP Texas	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	AEP Texas North Generation Company, LLC	Non Regulated Generation	100%	
2	AEP Texas Central Transition Funding LLC	Financing	100%	
3	AEP Texas Central Transition Funding II LLC	Financing	100%	
4	AEP Texas Central Transition Funding III LLC	Financing	100%	
5	AEP Texas Restoration Funding LLC	Financing	100%	

Name of Respondent: AEP Texas	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				

Name of Respondent: AEP Texas	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

Name of Respondent: AEP Texas	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	Judith E. Talavera, President and Chief Operating Officer	Columbus, Ohio		
7	Toby L. Thomas, Vice President	Columbus, Ohio		
8	Phillip R. Ulrich, Vice President	Columbus, Ohio		
9	Christian T. Beam, Vice President	Columbus, Ohio		
10	Peggy I. Simmons, Vice President	Columbus, Ohio		
11	Rajagopalan, Sundararajan, Executive Vice President	Columbus, Ohio		
12	Antonio P. Smyth, Vice President	Columbus, Ohio		
13	Charles E Zebula,Chief Financial Officer and Vice President	Columbus, Ohio		
14	The Respondent does not have an Executive Committee.			

Name of Respondent: AEP Texas	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)
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Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
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41		

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Name of Respondent: AEP Texas	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)
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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)
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Name of Respondent: AEP Texas	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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44				
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Name of Respondent: AEP Texas	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.

1)

By Company-Community [full name of village, township or city, county and include state]	Renewal Date/Auto Renewal [state date or auto]	Consideration [state dollar amount or state none]
City of Alton, Hidalgo County TX	3/31/2048	none
City of Refugio, Refugio County, TX	5/10/2048	none
City of Gregory, San Patricio County, TX	5/23/2053	none
City of Penitas, Hidalgo County, Texas	3/1/2048	none
City of Asherton, Dimmit County TX	5/1/2043	$0.003017/kWh for all retail kWh delivered with City's boundaries
City of Ganado	8/3/2053	none
City of Point Comfort	10/26/2053	none
Town of Woodsboro	6/30/2038	none
Aransas Pass, TX	8/18/2038	none
County of Zapatas	9/1/2048	none
City of Odem	10/4/2038	none
City of South Padre Island	12/31/2053	none
City of Taft	10/11/2043	none

None

None

None

None

Short-Term Debt and Commercial PaperFERC Authority (Docket No. ES21-61-000) for AEP Texas IncAEP Texas Inc (amount decrease/renewed for 1 yr)$1,800,000 Letter of Credit issued by American Electric Power Company, Inc. on behalf of AEP Texas Inc to benefit UFG Specialty Insurance.FERC Authority (Docket No. ES21-61-000) for AEP Texas Inc.
FERC Authority (Docket No. ES21-61-000) for AEP Texas Inc.Long-Term Debt and Commercial PaperFERC Authority: ES22-61-000 for AEP Texas IncSeries M $450M AEP Texas Senior Unsecured NotesFERC Authority: ES22-61-000 for AEP Texas Pollution Control Bond Matagorda Series 1996 Remarketing $60M

None

None

None

None

Julia A. Sloat elected as Chair of the Board effective on 01-01-2023 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 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 Therace M. Risch resigned as Vice President effective on 08-18-2023 Charles E. Zebula resigned as Vice President effective on 08-18-2023 Toby L. Thomas resigned as 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: AEP Texas	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	13,866,736,672	12,787,829,220
3	Construction Work in Progress (107)	200	914,900,910	811,656,720
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		14,781,637,582	13,599,485,940
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,660,166,636.00	2,504,262,104
6	Net Utility Plant (Enter Total of line 4 less 5)		12,121,470,946	11,095,223,836
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		12,121,470,946	11,095,223,836
15	Utility Plant Adjustments (116)		(50,057,991)	(77,471,628)
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,558,370	1,953,794
19	(Less) Accum. Prov. for Depr. and Amort. (122)		989,033	974,418
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	26,590,178	26,282,729
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		10,331,870	10,472,161
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)		71,074,631	63,404,325
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)		109,566,016	101,138,592
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)			
36	Special Deposits (132-134)		378,617	159,461
37	Working Fund (135)		100,000	100,000
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		175,001,071	149,202,790
41	Other Accounts Receivable (143)		644,519	122,013
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,940,713	4,094,651
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		17,836,532	11,143,827
45	Fuel Stock (151)	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)
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	190,385,816	138,770,043
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		3,629,633	3,863,020
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		1,541,508	1,650,065
61	Accrued Utility Revenues (173)		82,349,589	91,357,892
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)			29,269
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)		466,926,572	392,303,730
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,518,715	32,850,698
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	394,404,958	365,054,106
73	Prelim. Survey and Investigation Charges (Electric) (183)		74,253	384,118
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		173	24
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	2,972,076	2,815,199
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		3,734,246	4,273,254
82	Accumulated Deferred Income Taxes (190)	234	173,451,767	176,810,845
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		608,156,187	582,188,243
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		13,256,061,731	12,093,382,772

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Name of Respondent: AEP Texas	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	1	1
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)		19,482	19,482
7	Other Paid-In Capital (208-211)	253	2,079,671,145	1,558,278,195
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	2,717,201,922	2,347,066,864
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	7,941,887	7,634,438
13	(Less) Reacquired Capital Stock (217)	250	40,947	40,947
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(8,661,163)	(8,620,860)
16	Total Proprietary Capital (lines 2 through 15)		4,796,132,327	3,904,337,173
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	5,713,501,510	5,388,511,362
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		11,869,040	12,294,945
24	Total Long-Term Debt (lines 18 through 23)		5,701,632,469	5,376,216,417
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		71,567,232	90,902,285
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		442,076	97,733
29	Accumulated Provision for Pensions and Benefits (228.3)		14,188,466	7,612,107
30	Accumulated Miscellaneous Operating Provisions (228.4)		(11,850)	
31	Accumulated Provision for Rate Refunds (229)		312,511	289,949
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		3,732,104	3,734,076
35	Total Other Noncurrent Liabilities (lines 26 through 34)		90,230,539	102,636,150
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		192,082,882	330,820,642
39	Notes Payable to Associated Companies (233)		103,653,424	96,457,658
40	Accounts Payable to Associated Companies (234)		45,215,131	59,337,259
41	Customer Deposits (235)		20,000	42,130
42	Taxes Accrued (236)	262	92,943,522	81,002,994
43	Interest Accrued (237)		47,208,971	46,119,932
44	Dividends Declared (238)			

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)
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		(38,524)	(30,824)
48	Miscellaneous Current and Accrued Liabilities (242)		45,527,916	55,455,771
49	Obligations Under Capital Leases-Current (243)		35,671,952	35,693,486
50	Derivative Instrument Liabilities (244)			(322,130)
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)		2,742,345	
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		565,027,619	704,576,918
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	5,375,873	6,073,525
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	179,847,270	146,709,786
60	Other Regulatory Liabilities (254)	278	516,374,193	531,645,004
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,237,427,064	1,147,818,719
64	Accum. Deferred Income Taxes-Other (283)		164,014,377	173,369,080
65	Total Deferred Credits (lines 56 through 64)		2,103,038,777	2,005,616,114
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		13,256,061,731	12,093,382,772

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Name of Respondent: AEP Texas	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	1,806,434,561	1,747,986,095			1,806,434,561	1,747,986,095				
3	Operating Expenses											
4	Operation Expenses (401)	320	541,468,774	555,745,918			541,468,774	555,745,918				
5	Maintenance Expenses (402)	320	92,216,845	93,730,233			92,216,845	93,730,233				
6	Depreciation Expense (403)	336	338,678,131	326,144,035			338,678,131	326,144,035				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	38,964	38,563			38,964	38,563				
8	Amort. & Depl. of Utility Plant (404-405)	336	42,432,461	38,054,563			42,432,461	38,054,563				
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)											

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)
13	(Less) Regulatory Credits (407.4)		(5,771,877)	(4,512,535)			(5,771,877)	(4,512,535)				
14	Taxes Other Than Income Taxes (408.1)	262	160,778,535	157,531,173			160,778,535	157,531,173				
15	Income Taxes - Federal (409.1)	262	13,647,317	36,187,495			13,647,317	36,187,495				
16	Income Taxes - Other (409.1)	262	2,611,971	2,151,499			2,611,971	2,151,499				
17	Provision for Deferred Income Taxes (410.1)	234, 272	166,282,945	238,914,516			166,282,945	238,914,516				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	106,997,230	200,543,325			106,997,230	200,543,325				
19	Investment Tax Credit Adj. - Net (411.4)	266	(697,652)	(726,263)			(697,652)	(726,263)				
20	(Less) Gains from Disp. of Utility Plant (411.6)		158,635	209,145			158,635	209,145				
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		5	232			5	232				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		218,735	213,654			218,735	213,654				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,256,293,033	1,251,745,218			1,256,293,033	1,251,745,219				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		550,141,528	496,240,877			550,141,528	496,240,876				
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)		10,801	53								

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)
35	Nonoperating Rental Income (418)		250	250								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	307,449	(65,429)								
37	Interest and Dividend Income (419)		63,943	2,803,098								
38	Allowance for Other Funds Used During Construction (419.1)		28,417,440	19,659,325								
39	Miscellaneous Nonoperating Income (421)		4,578,025	3,062,738								
40	Gain on Disposition of Property (421.1)			10,166								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		33,356,306	25,470,096								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		12,075	14,671								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		515,015	10,375,111								
46	Life Insurance (426.2)		940,846	(418,173)								
47	Penalties (426.3)		24,958	201,377								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,089,453	1,198,539								
49	Other Deductions (426.5)		(24,634,128)	8,206,275								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		(22,051,781)	19,577,800								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262										
53	Income Taxes-Federal (409.2)	262	6,130,937	(7,083,951)								
54	Income Taxes-Other (409.2)	262	130,860									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	7,292,238	5,169,458								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,507,314	1,422,769								

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)
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)		11,046,721	(3,337,262)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		44,361,367	9,229,558								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		232,641,166	201,492,960								
63	Amort. of Debt Disc. and Expense (428)		4,838,779	4,439,151								
64	Amortization of Loss on Reaquired Debt (428.1)		539,008	514,039								
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)		10,792,960	878,527								
68	Other Interest Expense (431)		(1,365,936)	1,768,832								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		23,385,589	11,522,066								
70	Net Interest Charges (Total of lines 62 thru 69)		224,060,388	197,571,444								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		370,442,506	307,898,992								
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										

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)
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		[a]370,442,506	307,898,992								
						Page 114-117						

Name of Respondent: AEP Texas	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: NetIncomeLoss

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

FOOTNOTE DATA

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

Net Income for the Year per Page 117	370,443
Federal & State Income Taxes	85,894
Pre-Tax Book Income	456,337
AFUDC / Interest Capitalized	(20,202)
Asset Retirement Obligation	502
Capitalized Relocation Costs	(7,236)
Deferred Intercompany Tax Gain	143
Misc Overheads Capitalized	—
Excess Tax Vs Book Depreciation	(335,061)
Book Accruals	(10,693)
Removal Costs	(68,851)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)	(7,904)
Provision for Possible Revenue Refund	(277)
Book Reserves	(27,414)
Deferred Revenues - Equity Return Securitization Revenue	(9,886)
Impaired Asset	92,629
Provision for Damages	(6,914)
Other (Net)	9,276
Taxable Income before State Taxes	64,447
Less : State & Local Current Tax	2,452
Federal Taxable Income	61,995
FIT on Current Year Taxable Income	13,019
Adjustment due to System Consolidation (a)	77
Tax Credits	214
NOL Reclass	(13,652)
Estimated Tax Currently Payable (b)	26,380
Adjustments of Prior Year's Accruals & Other Adjustments	(6,602)
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	19,778

(a)
Instruction 2

FOOTNOTE DATA

* The tax computation about represents an estimate of the Company's allocated portion of the Systems Consolidated Federal Income Tax. The computation of actual 2022 System Federal Income Taxes will not be available until the consolidated Federal Income Tax Return is completed and filed by October 2023. The actual consolidated group will not be available until after the consolidated Federal Income Tax Return is filed.

Name of Respondent: AEP Texas	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		2,347,066,864	2,039,102,442
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			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		370,135,058	307,964,422
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)			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,717,201,922	2,347,066,864
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)		2,717,201,922	2,347,066,864
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		7,634,438	7,699,867
50	Equity in Earnings for Year (Credit) (Account 418.1)		307,449	(65,429)
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)		7,941,887	7,634,438

Name of Respondent: AEP Texas	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)	[(b)]370,442,506	307,898,992
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	381,149,555	364,237,161
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	5,771,877	4,512,535
8	Deferred Income Taxes (Net)	64,070,639	42,117,880
9	Investment Tax Credit Adjustment (Net)	(697,652)	(726,263)
10	Net (Increase) Decrease in Receivables	(32,058,873)	(30,949,714)
11	Net (Increase) Decrease in Inventory	(51,615,774)	(64,902,851)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(18,104,632)	44,722,784
14	Net (Increase) Decrease in Other Regulatory Assets	(20,980,602)	20,623,031
15	Net Increase (Decrease) in Other Regulatory Liabilities	(6,534,037)	6,231,981
16	(Less) Allowance for Other Funds Used During Construction	28,417,440	19,659,325
17	(Less) Undistributed Earnings from Subsidiary Companies	307,449	(65,429)
18	Other (provide details in footnote):		
18.1	[(a)]Other (provide details in footnote):	(94,871,722)	(36,385,482)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	567,846,396	637,786,158
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,516,060,227)	(1,330,598,294)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(28,417,440)	(19,659,325)
31	Other (provide details in footnote):		
31.1	Acquired Assets	(1,607,279)	(1,384,858)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,489,250,066)	(1,312,323,827)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(c)]9,108,124	5,015,132
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		

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)
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Contribution In Aid of Construction Proceeds	61,885,658	31,365,978
53.2	(Increase) Decrease in Other Special Deposits	(32,882)	4,569
53.3	Notes Receivable from Associated Companies		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,418,289,166)	(1,275,938,147)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	510,000,000	1,200,000,000
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	(4,643,136)	(11,370,234)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds on Capital Leaseback	1,507,043	642,128
67.2	Notes Payable to Associated Companies - Issued	7,195,766	69,559,113
67.3	Capital Contributions from Parent	521,392,950	4,330,402
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,035,452,622	1,263,161,409
72	Payments for Retirement of:		
73	Long-term Debt (b)	(185,009,852)	(625,009,420)
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		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	850,442,770	638,151,989
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)		
88	Cash and Cash Equivalents at Beginning of Period	100,000	100,000
90	Cash and Cash Equivalents at End of Period	100,000	100,000
	Page 120-121		

Name of Respondent: AEP Texas	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	$ (94,110,295)	$ (74,290,143)
Property and Investments, Net	(449,670)	4,858,521
Margin Deposits	(186,274)	514,818
Mark-to-Market of Risk Management Contracts	351,399	(350,347)
Prepayments	(10,613,183)	(5,653,365)
Accrued Utility Revenues, Net	9,008,303	(13,431,203)
Unamortized Debt Expense	3,246,118	2,449,930
Other Deferred Debits, Net	3,715,723	2,699,384
Other Comprehensive Income, Net	3,018,636	1,056,015
Unamortized Discount/Premium on Long-Term Debt	1,154,904	1,119,861
Accumulated Provisions - Misc	(1,466,670)	(411,049)
Current and Accrued Liabilities, Net	(8,673,464)	7,440,305
Other Deferred Credits, Net	132,748	37,611,794
Total	**$ (94,871,725)**	**$ (36,385,479)**

(b) Concept: NetIncomeLoss

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

FOOTNOTE DATA

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

Net Income for the Year per Page 117	370,443
Federal & State Income Taxes	85,894
Pre-Tax Book Income	456,337
AFUDC / Interest Capitalized	(20,202)
Asset Retirement Obligation	502
Capitalized Relocation Costs	(7,236)
Deferred Intercompany Tax Gain	143
Misc Overheads Capitalized	—
Excess Tax Vs Book Depreciation	(335,061)
Book Accruals	(10,693)
Removal Costs	(68,851)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)	(7,904)
Provision for Possible Revenue Refund	(277)
Book Reserves	(27,414)
Deferred Revenues - Equity Return Securitization Revenue	(9,886)
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Provision for Damages	(6,914)
Other (Net)	9,276
Taxable Income before State Taxes	64,447
Less : State & Local Current Tax	2,452
Federal Taxable Income	61,995
FIT on Current Year Taxable Income	13,019
Adjustment due to System Consolidation (a)	77
Tax Credits	214
NOL Reclass	(13,652)
Estimated Tax Currently Payable (b)	26,380
Adjustments of Prior Year's Accruals & Other Adjustments	(6,602)
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	19,778

(a)
Instruction 2

FOOTNOTE DATA

* The tax computation about represents an estimate of the Company's allocated portion of the Systems Consolidated Federal Income Tax. The computation of actual 2022 System Federal Income Taxes will not be available until the consolidated Federal Income Tax Return is completed and filed by October 2023. The actual consolidated group will not be available until after the consolidated Federal Income Tax Return is filed.

(c) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Land sale 7.09 acres	$ —	$ 1,889,221
Sale of 345kV McAllen	—	136,634
Sale of Meters	63,136	51,328
Sale of Transformers	6,923,385	2,939,602
Land sale Harlingen, TX	2,121,603	—
Total	**$ 9,108,124**	**$ 5,016,785**

Name of Respondent: AEP Texas	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 System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
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.
IRA	On August 16, 2022, President Biden signed into law legislation commonly referred to as the “Inflation Reduction Act” (IRA).
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
MTM	Mark-to-Market.
NOL	Net operating losses.
OATT	Open Access Transmission Tariff.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PTC	Production Tax Credit.
PUCT	Public Utility Commission of Texas.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
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.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Organized in Delaware in 1925, AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,111,000 retail customers through REPs in west, central and southern Texas. As of December 31, 2023, AEP Texas had 1,646 employees. Among the principal industries served by AEP Texas are petroleum and coal products manufacturing, chemical manufacturing, oil and gas extraction, pipeline transportation, primary metal manufacturing, data processing and support activities for mining. The territory served by AEP Texas also includes several military installations. AEP Texas is a member of ERCOT.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP Texas' rates are regulated by the FERC and the PUCT. The FERC also regulates AEP Texas' 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 PUCT also regulates certain intercompany transactions under various orders and affiliate statutes. Both the FERC and the PUCT 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. AEP Texas' 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 AEP Texas 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 PUCT regulates all of the retail distribution operations and rates of AEP Texas' retail public utility subsidiaries on a cost basis. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has one active REP in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind assets, the power from which is marketed and sold in ERCOT.

The FERC also regulates AEP Texas' wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. AEP Texas' retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT.

Basis of Accounting

AEP Texas's accounting is subject to the requirements of the 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 requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of an accrued provision for potential refund as other noncurrent liability rather than a current liability.
- 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 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 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 accounting for AEP Texas Central Transition Funding II LLC, AEP Texas Central Transition Funding III LLC and AEP Texas Restoration Funding LLC as nonaffiliated companies rather than consolidating the entities in accordance with the accounting guidance for "Variable Interest Entities."
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment.
- The classification of deferred equity income in other deferred credits rather than in other non-current assets as securitized transition assets.
- The classification of amortization of deferred equity in operating revenues rather than in depreciation and amortization.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of non-service cost components of net periodic benefit cost as operating expense instead of other income (expense).
- The classification of operating lease assets as utility plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in obligations under capital leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of other income (expense).
- The classification of cloud computing implementation costs as utility plant rather than as a noncurrent asset.

Accounting for the Effects of Cost-Based Regulation

AEP Texas' 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 for:		
Interest (Net of Capitalized Amounts)	$ 217.7	$ 188.6
Income Taxes (Net of Refunds)	11.4	15.5
Noncash Acquisitions Under Finance Leases	4.8	6.1
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	112.2	235.4

Special Deposits

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

Inventory

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, AEP Texas accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

For AEP Texas, allowances for uncollectible accounts are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. 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

AEP Texas had significant transactions with REPs which on a combined basis account for the following percentages of Operating Revenues for the years ended December 31 and Customer Accounts Receivable as of December 31:

Significant Customers of AEP Texas: NRG Energy and TXU Energy	2023	2022
Percentage of Operating Revenues	43 %	48 %
Percentage of Customer Accounts Receivable	35 %	43 %

AEP Texas monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The PUCT allows 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.

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 Company

AEP Texas has a wholly-owned subsidiary, AEP Texas North Generation Company, LLC. AEP Texas transferred all of its mothballed generation assets and related liabilities to this subsidiary, substantially completing the business separation requirement of the Texas Restructuring Legislation.

AEP Texas also has three wholly-owned subsidiaries, AEP Texas Central Transition Funding II LLC, AEP Texas Central Transition Funding III LLC and AEP Texas Restoration Funding LLC, that are engaged in financing activities associated with AEP Texas' securitized assets. Investments in the net assets of AEP Texas's three wholly-owned subsidiaries are carried at cost plus equity in their undistributed earnings since creation.

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

AEP Texas 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, solar 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. AEP Texas 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 AEP Texas plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when AEP Texas 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.

Revenue Recognition

Regulatory Accounting

AEP Texas' 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

AEP Texas recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. AEP Texas 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.

Maintenance

AEP Texas expenses maintenance costs as incurred. If it becomes probable that AEP Texas 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.

Income Taxes and Investment Tax Credits

AEP Texas 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.

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

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

AEP Texas joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The benefit of current tax loss of the parent company (Parent Company Loss Benefit) to AEP Texas is accounted for as an allocation through equity. The consolidated NOL of the AEP System is allocated to each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System NOL, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Excise Taxes

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

AEP Texas participates in an AEPSC sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all AEP Texas employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. AEP Texas also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees. AEP Texas is allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. See Note 7 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30 %
Fixed Income	54 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	58 %
Fixed Income	41 %
Cash and Cash Equivalents	1 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2023 and 2022, the fair value of securities on loan as part of the program was $62 million and $83 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2023 and 2022.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2023 through February 26, 2024, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 9, 2023. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. <u>NEW ACCOUNTING STANDARDS</u>

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 AEP Texas' business. The following standards will impact the AEP Texas' 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

AEP Texas' balances in AOCI were not material as of December 31, 2023 and 2022 and the activities within AOCI were not material for the years ended December 31, 2023 and 2022.

4. RATE MATTERS

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

AEP Texas Interim Transmission and Distribution Rates

Through December 31, 2023, AEP Texas' cumulative revenues from interim base rate increases that are subject to prudency review is approximately $987 million. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition. AEP Texas is required to file for a comprehensive rate review no later than April 5, 2024.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2023	December 31, 2022	Remaining Recovery Period
	(in millions)		
Regulatory Assets:			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Texas Mobile Generation Lease Payments	$ —	$ 17.6	
Total Regulatory Assets Currently Earning a Return	—	17.6	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	37.7	26.7	
Line Inspection Costs	5.7	4.5	
Vegetation Management Program	5.2	5.2	
Texas Retail Electric Provider Bad Debt Expense	4.0	4.1	
Other Regulatory Assets Pending Final Regulatory Approval	11.7	8.9	
Total Regulatory Assets Currently Not Earning a Return	64.3	49.4	
Total Regulatory Assets Pending Final Regulatory Approval	64.3	67.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Texas Mobile Temporary Emergency Electric Energy Facilities Rider	33.4	—	2 years
Meter Replacement Costs	9.4	16.1	2 years
Other Regulatory Assets Approved for Recovery	0.7	1.4	various
Total Regulatory Assets Currently Earning a Return	43.5	17.5	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	183.2	173.2	12 years
Peak Demand Reduction/Energy Efficiency	9.2	11.9	2 years
Vegetation Management Program	6.8	12.1	2 years
Income Tax Assets	82.8	71.1	(a)
Storm-Related Costs	4.3	8.5	2 years
Other Regulatory Assets Approved for Recovery	0.3	3.8	various
Total Regulatory Assets Currently Not Earning a Return	286.6	280.6	
Total Regulatory Assets Approved for Recovery	330.1	298.1	
Total FERC Account 182.3 Regulatory Assets	$ 394.4	$ 365.1	

(a) 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			
Income Tax Liabilities (a)	$ 13.0	$ 13.0	(b)
Total Regulatory Liabilities Currently Paying a Return	13.0	13.0	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	1.5	1.8	
Total Regulatory Liabilities Currently Not Paying a Return	1.5	1.8	
Total Regulatory Liabilities Pending Final Regulatory Determination	14.5	14.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes Liabilities (a)	494.8	502.6	(b)
Other Regulatory Liabilities Approved for Payment	3.8	4.3	various
Total Regulatory Liabilities Currently Paying a Return	498.6	506.9	
Regulatory Liabilities Currently Not Paying a Return			
Restoration Charges	1.2	3.3	6 years
Other Regulatory Liabilities Approved for Payment	2.1	6.6	various
Total Regulatory Liabilities Currently Not Paying a Return	3.3	9.9	
Total Regulatory Liabilities Approved for Payment	501.9	516.8	
Total FERC 254 Account Regulatory Liabilities	$ 516.4	$ 531.6	

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

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

GUARANTEES

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

Letters of Credit

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

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

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of AEP Texas under six uncommitted facilities totaling $450 million. AEP Texas' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2023 was $1.8 million with a maturity date of July 2024.

Indemnifications and Other Guarantees

Contracts

AEP Texas 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.

Lease Obligations

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

ENVIRONMENTAL CONTINGENCIES

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

The transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. AEP Texas 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. 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

AEP Texas maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. AEP Texas also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes 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 AEP Texas. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

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

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

AEP Texas participates in an AEPSC 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. AEP Texas also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

AEP Texas 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. AEP Texas recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. AEP Texas 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	5.20 % (a)	5.15 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 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 (a)	5.20 %	5.15 %	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	December 31,	
Health Care Trend Rates	**2023**	**2022**
Initial	7.00 %	7.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2030	2029

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. 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 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 334.1	$ 419.8	$ 68.6	$ 80.5
Service Cost	8.2	11.1	0.3	0.5
Interest Cost	18.3	12.1	3.6	2.2
Actuarial (Gain) Loss	20.1	(67.8)	1.2	(7.1)
Benefit Payments	(37.6)	(41.1)	(10.7)	(10.9)
Participant Contributions	—	—	3.4	3.4
Benefit Obligation as of December 31,	$ 343.1	$ 334.1	$ 66.4	$ 68.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 335.1	$ 444.9	$ 128.3	$ 168.8
Actual Gain (Loss) on Plan Assets	34.8	(69.2)	16.5	(33.0)
Company Contributions	0.4	0.5	—	—
Participant Contributions	—	—	3.4	3.4
Benefit Payments	(37.6)	(41.1)	(10.7)	(10.9)
Fair Value of Plan Assets as of December 31,	$ 332.7	$ 335.1	$ 137.5	$ 128.3
Funded (Underfunded) Status as of December 31,	$ (10.4)	$ 1.0	$ 71.1	$ 59.7

	Pension Plans		OPEB	
	December 31,			
	2023	2022	2023	2022
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ 0.1	$ 3.7	$ 71.1	$ 59.7
Miscellaneous Current and Accrued Liabilities – Short-term Benefit Liability	(0.3)	(0.4)	—	—
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(10.2)	(2.3)	—	—
Funded (Underfunded) Status	$ (10.4)	$ 1.0	$ 71.1	$ 59.7

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	
	December 31,			
	2023	2022	2023	2022
Components	(in millions)			
Net Actuarial Loss	$ 175.2	$ 161.9	$ 22.1	$ 29.7
Prior Service Credit	—	—	(2.3)	(7.6)
Recorded as				
Regulatory Assets	$ 163.4	$ 151.2	$ 19.8	$ 22.0
Deferred Income Taxes	2.7	2.4	—	0.1
Net of Tax AOCI	9.1	8.3	—	—

	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 13.4	$ 22.4	$ (6.4)	$ 34.9
Amortization of Actuarial Loss	(0.1)	(5.2)	(1.2)	—
Amortization of Prior Service Credit	—	—	5.3	6.1
Change for the Year Ended December 31,	$ 13.3	$ 17.2	$ (2.3)	$ 41.0

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 AEP Texas using the percentages in the table below:

Pension Plan		OPEB	
December 31,			
2023	2022	2023	2022
8.1 %	8.1 %	8.2 %	8.3 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 347.6	$ —	$ —	$ —	$ 347.6	8.4 %
International	398.4	—	—	—	398.4	9.7 %
Common Collective Trusts (b)	—	—	—	379.9	379.9	9.2 %
Subtotal – Equities	746.0	—	—	379.9	1,125.9	27.3 %
Fixed Income (a):						
United States Government and Agency Securities	(0.6)	1,071.4	—	—	1,070.8	26.0 %
Corporate Debt	—	891.7	—	—	891.7	21.6 %
Foreign Debt	—	140.2	—	—	140.2	3.4 %
State and Local Government	—	37.0	—	—	37.0	0.9 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(0.6)	2,141.1	—	—	2,140.5	51.9 %
Infrastructure (b)	—	—	—	109.2	109.2	2.6 %
Real Estate (b)	—	—	—	276.9	276.9	6.7 %
Alternative Investments (b)	—	—	—	319.7	319.7	7.8 %
Cash and Cash Equivalents (b)	—	64.9	—	58.3	123.2	3.0 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	29.3	29.3	0.7 %
Total	$ 745.4	$ 2,206.0	$ —	$ 1,173.3	$ 4,124.7	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 414.1	$ —	$ —	$ —	$ 414.1	26.7 %
International	265.0	—	—	—	265.0	17.1 %
Common Collective Trusts (a)	—	—	—	169.1	169.1	10.9 %
Subtotal – Equities	679.1	—	—	169.1	848.2	54.7 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	120.3	120.3	7.8 %
United States Government and Agency Securities	0.1	155.8	—	—	155.9	10.1 %
Corporate Debt	—	141.5	—	—	141.5	9.1 %
Foreign Debt	—	21.0	—	—	21.0	1.4 %
State and Local Government	62.9	7.8	—	—	70.7	4.6 %
Subtotal – Fixed Income	63.0	326.1	—	120.3	509.4	33.0 %
Trust Owned Life Insurance:						
International Equities	—	46.7	—	—	46.7	3.0 %
United States Bonds	—	110.3	—	—	110.3	7.1 %
Subtotal – Trust Owned Life Insurance	—	157.0	—	—	157.0	10.1 %
Cash and Cash Equivalents (a)	23.2	—	—	6.7	29.9	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	4.8	4.8	0.3 %
Total	$ 765.3	$ 483.1	$ —	$ 300.9	$ 1,549.3	100.0 %

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

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	December 31, 2023	2022
	(in millions)	
Qualified Pension Plan	$ 321.1	$ 315.4
Nonqualified Pension Plans	2.1	2.5
Total	$ 323.2	$ 317.9

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	December 31, 2023	2022
	(in millions)	
Projected Benefit Obligation	$ 343.1	$ 2.7
Fair Value of Plan Assets	332.7	—
Underfunded Projected Benefit Obligation	$ (10.4)	$ (2.7)

Accumulated Benefit Obligation

	December 31,	
	2023	2022
	(in millions)	
Accumulated Benefit Obligation	$ 2.1	$ 2.5
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (2.1)	$ (2.5)

Estimated Future Benefit Payments and Contributions

AEP Texas expects contributions and payments for the pension plans of $300 thousand during 2024. For the pension plans, this amount includes the payment of unfunded non-qualified 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, AEP Texas 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 AEP Texas' 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	OPEB
	(in millions)	
2024	$ 36.7	$ 9.4
2025	34.3	10.0
2026	34.5	10.2
2027	32.2	10.2
2028	32.2	9.9
Years 2029 to 2033, in Total	133.5	45.2

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	$ 8.2	$ 11.1	$ 0.3	$ 0.5
Interest Cost	18.3	12.1	3.6	2.2
Expected Return on Plan Assets	(28.1)	(21.0)	(9.0)	(9.1)
Amortization of Prior Service Credit	—	—	(5.3)	(6.1)
Amortization of Net Actuarial Loss	0.1	5.2	1.2	—
Net Periodic Benefit Cost (Credit)	(1.5)	7.4	(9.2)	(12.5)
Capitalized Portion	(4.7)	(6.2)	(0.2)	(0.3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (6.2)	$ 1.2	$ (9.4)	$ (12.8)

American Electric Power System Retirement Savings Plan

AEP Texas participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for 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 were $7 million and $7 million for the years ended December 31, 2023 and 2022, respectively.

8. BUSINESS SEGMENTS

AEP Texas has one reportable segment, an electricity transmission and distribution business. AEP Texas' other activities are insignificant.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP Texas.

Risk Management Strategies

AEP Texas' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEP Texas utilizes financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. AEP Texas does not hedge all fuel price risk. The gross notional volumes of AEP Texas' outstanding derivative contracts for heating oil and gasoline as of December 31, 2023 and 2022 were 2 million gallons for both years.

Cash Flow Hedging Strategies

AEP Texas utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. AEP Texas also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. AEP Texas 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, AEP Texas 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," AEP Texas 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, AEP Texas 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 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 immaterial as of December 31, 2023 and 2022.

The following table represents the gross fair value of AEP Texas' derivative activity on the balance sheets as of December 31, 2023. There were no derivative instrument assets and derivative instrument liabilities outstanding as of December 31, 2022.

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Hedging Contracts- Interest Rate (a)	Gross Amounts of Risk Management Assets/Liabilities Recognized	Gross Amounts Offset on the Balance Sheets (b)	Net Amounts of Assets/Liabilities Presented on the Balance Sheets (c)
	December 31, 2023				
			(in millions)		
Derivative Instrument Assets	$ —	$ —	$ —	$ —	$ —
Long-Term Portion of Derivative Instrument Assets	—	—	—	—	—
Derivative Instrument Liabilities	0.2	2.7	2.9	(0.2)	2.7
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 on the balance sheets.

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	$ (0.1)	$ 1.5
Maintenance Expenses	(0.3)	1.8
Other Regulatory Assets (a)	(0.2)	0.1
Other Regulatory Liabilities (a)	—	(0.6)
Total Gain (Loss) on Risk Management Contracts	$ (0.6)	$ 2.8

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on 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), AEP Texas 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.

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

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

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

Impact of Cash Flow Hedges on the Balance Sheets

December 31, 2023		December 31, 2022	
Interest Rate			
AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months
(in millions)			
$ 0.5	$ 0.2	$ (0.3)	$ (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.

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

December 31, 2023		2022	
Book Value	Fair Value	Book Value	Fair Value
(in millions)			
$ 5,701.6	$ 5,188.3	$ 5,376.2	$ 4,746.5

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 table sets forth, by level within the fair value hierarchy, AEP Texas' financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2023. There were no assets and liabilities measured at fair value on a recurring basis as of December 31, 2022. 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
Liabilities:	(in millions)				
Risk Management Liabilities					
Risk Management Commodity Contracts (a)	$ —	$ 0.2	$ —	$ (0.2)	$ —
Cash Flow Hedges:					
Interest Rate Hedges	—	2.7	—	—	2.7
Total Liabilities	$ —	$ 2.9	$ —	$ (0.2)	$ 2.7

(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."

11. INCOME TAXES

Income Tax Expense (Credit)

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

	Years Ended December 31,	
	2023	2022
	(in millions)	
Charged to Operating Expenses, Net:		
Current	$ 16.3	$ 38.3
Deferred	58.6	37.7
Total	74.9	76.0
Charged (Credited) to Nonoperating Income, Net:		
Current	6.2	(7.1)
Deferred	4.8	3.7
Total	11.0	(3.4)
Total Income Taxes	$ 85.9	$ 72.6

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

	Years Ended December 31,	
	2023	2022
	(in millions)	
Net Income	$ 370.4	$ 307.9
Income Tax Expense	85.9	72.6
Pretax Income	$ 456.3	$ 380.5
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 95.8	$ 79.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
State and Local Income Taxes, Net	2.1	1.7
AFUDC	(6.0)	(4.1)
Tax Reform Excess ADIT Reversal	(6.0)	(5.5)
Other	—	0.6
Income Tax Expense	$ 85.9	$ 72.6
Effective Income Tax Rate	18.8 %	19.1 %

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

	December 31,	
	2023	2022
	(in millions)	
Deferred Tax Assets	$ 173.6	$ 177.0
Deferred Tax Liabilities	(1,401.4)	(1,321.2)
Net Deferred Tax Liabilities	$ (1,227.8)	$ (1,144.2)
Property Related Temporary Differences	$ (1,227.1)	$ (1,130.7)
Amounts Due to Customers for Future Federal Income Taxes	109.3	111.0
Deferred State Income Taxes	(41.5)	(36.6)
Regulatory Assets	(57.6)	(48.9)
Securitized Transition Assets	(45.6)	(65.0)
Tax Credit Carryforward	13.7	—
Operating Lease Liability	16.6	20.3
Deferred Revenues	2.9	2.9
All Other, Net	1.5	2.8
Net Deferred Tax Liabilities	$ (1,227.8)	$ (1,144.2)

Federal and State Income Tax Audit Status

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

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

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2019 and 2021 resulted in unused federal and state income tax credits. As of December 31, 2023, AEP Texas has federal tax credit carryforwards in the amount of $14 million. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041. AEP Texas anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

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

AEP Texas and other AEP subsidiaries expect to be applicable corporations for purpose 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 are presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP Texas and other AEP subsidiaries present the loss on sale of tax credits through income tax expense.

12. <u>LEASES</u>

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

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

	Years Ended December 31, 2023	Years Ended December 31, 2022
	(in millions)	
Operating Lease Cost	$ 34.0	$ 18.4
Finance Lease Cost:		
Amortization of Right-of-Use Assets	7.4	6.8
Interest on Lease Liabilities	1.4	1.3
Total Lease Rental Costs (a)	$ 42.8	$ 26.5

(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	December 31, 2022
Weighted-Average Remaining Lease Term (years):		
Operating Leases	3.99	4.33
Finance Leases	5.13	5.39
Weighted-Average Discount Rate:		
Operating Leases	4.23 %	4.15 %
Finance Leases	5.27 %	4.75 %

	Year Ended December 31, 2023	Year Ended December 31, 2022
	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating Cash Flows from Operating Leases	$ 33.6	$ 18.3
Operating Cash Flows from Finance Leases	8.8	8.1
Non-cash Acquisitions Under Operating Leases	$ 12.4	$ 36.7

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

	December 31, 2023	December 31, 2022
	(in millions)	
Property, Plant and Equipment Under Finance Leases:		
Utility Plant (a)	$ 27.6	$ 30.1
Net Property, Plant and Equipment Under Finance Leases	$ 27.6	$ 30.1
Obligations Under Finance Leases:		
Noncurrent	$ 20.6	$ 23.1
Current	7.0	7.0
Total Obligations Under Finance Leases	$ 27.6	$ 30.1

(a) Includes $26 million and $24 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

	December 31, 2023	December 31, 2022
	(in millions)	
Property, Plant and Equipment Under Operating Leases:		
Utility Plant (a)	$ 77.6	$ 94.7
Net Property, Plant and Equipment Under Operating Leases	$ 77.6	$ 94.7
Obligations Under Operating Leases:		
Noncurrent	$ 50.9	$ 67.8
Current	28.7	28.6
Total Obligations Under Operating Leases	$ 79.6	$ 96.4

(a) Includes $72 million and $48 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	$ 8.3	$ 32.1
2025	6.6	15.7
2026	5.1	13.3
2027	4.0	10.7
2028	2.8	7.8
After 2028	5.1	8.1
Total Future Minimum Lease Payments	31.9	87.7
Less: Imputed Interest	4.3	8.1
Estimated Present Value of Future Minimum Lease Payments	$ 27.6	$ 79.6

Master Lease Agreements

AEP Texas 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, AEP Texas 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 AEP Texas for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $11 million.

Lessor Activity

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

13. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average Interest Rate as of December 31, 2023	Interest Rate Ranges as of December 31, 2023	Interest Rate Ranges as of December 31, 2022	Outstanding as of December 31, 2023	Outstanding as of December 31, 2022
					(in millions)	
Senior Unsecured Notes	2025-2052	4.20%	2.10%-6.76%	2.10%-6.76%	$ 5,070.0	$ 4,745.0
Pollution Control Bonds	2029-2030 (a)	3.88%	2.60%-4.55%	0.90%-4.55%	442.6	442.6
Other Long-term Debt	2025-2059	6.70%	4.50%-6.71%	4.50%-5.67%	200.9	200.9
Unamortized Discount, Net					(11.9)	(12.3)
Total Long-term Debt Outstanding					$ 5,701.6	$ 5,376.2

(a) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.

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

	(in millions)
2024	$ —
2025	500.0
2026	50.0
2027	—
2028	500.0
After 2028	4,663.5
Principal Amount	5,713.5
Unamortized Discount, Net	(11.9)
Total Long-term Debt	$ 5,701.6

Dividend Restrictions

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

All of the dividends declared by AEP Texas 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 earning.

AEP Texas 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 AEP Texas is through the credit agreements. As of December 31, 2023, the maximum amount of restricted net assets of AEP Texas that may not be distributed to the Parent in the form of a loan, advance or dividend was $2.8 billion.

The credit agreement covenant restrictions can limit the ability of AEP Texas to pay dividends out of retained earnings. As of December 31, 2023, the amount of any such restrictions was $737 million.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of 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, respectively, on the balance sheets. AEP Texas' 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	Net Borrowings from the Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
			(in millions)			
2023	$ 477.5	$ 42.0	$ 216.8	$ 12.9	$ 103.7	$ 600.0
2022	348.8	652.3	173.3	247.8	96.5	500.0

The maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2023	5.81 %	4.66 %	5.72 %	5.70 %	5.46 %	5.71 %
2022	5.28 %	0.10 %	4.81 %	0.69 %	1.08 %	1.99 %

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 $11 million and $900 thousand for the years ended December 31, 2023 and 2022, respectively, and interest income related to the corporate borrowing programs were $100 thousand and $3 million for the years ended December 31, 2023 and 2022, respectively.

Credit Facilities

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

14. RELATED PARTY TRANSACTIONS

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

Intercompany Billings

AEP Texas performs 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.

Sales and Purchases of Property

AEP Texas had affiliated sales and purchases of electric property amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the year 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. There were no charitable contributions made to the AEP Foundation in 2023. In 2022, AEP Texas contributed $10 million to the AEP Foundation which was recorded in Donations on the statements of income.

Affiliated Revenues and Purchases

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

Related Party Revenues	Years Ended December 31, 2023	2022
	(in millions)	
Other Revenues	$ 4.9	$ 3.5

ERCOT Transmission Service Charges

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $29 million and $29 million for transmission services for the years ended December 31, 2023 and 2022, respectively. The billings are recorded in Operation Expenses on AEP Texas' statements of income.

AEPSC

AEPSC provides certain managerial and professional services to AEP Texas. The costs of the services are based on a direct charge or on a prorated basis and billed to AEP Texas at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. AEP Texas' total billings from AEPSC were $228 million and $237 million for the years ended December 31, 2023 and 2022, respectively.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

AEP Texas 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	Transmission	Distribution	General
		(in percentages)	
2023	2.2 %	2.9 %	6.0 %
2022	2.2 %	2.9 %	6.2 %

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

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

Year	ARO at January 1,	Accretion Expense	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in millions)		
2023	$ 3.8	$ 0.2	$ (0.3)	$ 0.1	$ 3.8
2022	3.8	0.2	(0.2)	—	3.8

16. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

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

	Years Ended December 31, 2023	2022
	(in millions)	
Retail Revenues:		
Residential Revenues	$ 612.8	$ 620.9
Commercial Revenues	367.9	371.2
Industrial Revenues	135.5	128.0
Other Retail Revenues	34.1	33.8
Total Retail Revenues	1,150.3	1,153.9
Wholesale Revenues:		
Transmission Revenues	619.0	563.8
Total Wholesale Revenues	619.0	563.8
Other Revenues from Contracts with Customers (a)	32.1	22.6
Total Revenues from Contracts with Customers	1,801.4	1,740.3
Other Revenues:		
Alternative Revenues	(4.2)	(1.2)
Other Revenues	9.2	8.9
Total Other Revenues	5.0	7.7
Total Operating Revenues	$ 1,806.4	$ 1,748.0

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

AEP Texas 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. AEP Texas 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 AEP Texas are summarized as follows:

Retail Revenues

AEP Texas 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 AEP Texas 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. Payments from REPs are due to AEP Texas within 35 days.

Wholesale Revenues - Transmission

AEP Texas has performance obligations to transmit electricity to wholesale customers through assets owned and operated. The performance obligation to provide transmission services in ERCOT is partially fixed for a period of one year or less. Payments from ERCOT for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for ERCOT.

Contract Assets and Liabilities

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

When AEP Texas 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. AEP Texas’ contract liabilities typically arise from services provided under joint use agreements for utility poles. AEP Texas 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 AEP Texas’ balance sheets within the Customer Accounts Receivable line item. AEP Texas’ 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.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on AEP Texas’ balance sheets was immaterial as of December 31, 2023 and 2022.

Contract Costs

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

Name of Respondent: AEP Texas	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				(5,299,494)	(1,232,018)		(6,531,511)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				13,938,916	1,056,015		14,994,932		
3	Preceding Quarter/Year to Date Changes in Fair Value				(17,084,280)			(17,084,280)		
4	Total (lines 2 and 3)				(3,145,364)	1,056,015		(2,089,348)	307,898,992	305,809,644
5	Balance of Account 219 at End of Preceding Quarter/Year				(8,444,857)	(176,002)		(8,620,860)		
6	Balance of Account 219 at Beginning of Current Year				(8,444,857)	(176,002)		(8,620,860)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				9,088,603	852,183		9,940,787		
8	Current Quarter/Year to Date Changes in Fair Value				(9,981,090)			(9,981,090)		
9	Total (lines 7 and 8)				(892,487)	852,183		(40,303)	[a]370,442,506	370,402,203
10	Balance of Account 219 at End of Current Quarter/Year				(9,337,344)	676,181		(8,661,163)		

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Name of Respondent: AEP Texas	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: NetIncomeLoss

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

FOOTNOTE DATA

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

Net Income for the Year per Page 117	370,443
Federal & State Income Taxes	85,894
Pre-Tax Book Income	456,337
AFUDC / Interest Capitalized	(20,202)
Asset Retirement Obligation	502
Capitalized Relocation Costs	(7,236)
Deferred Intercompany Tax Gain	143
Misc Overheads Capitalized	—
Excess Tax Vs Book Depreciation	(335,061)
Book Accruals	(10,693)
Removal Costs	(68,851)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)	(7,904)
Provision for Possible Revenue Refund	(277)
Book Reserves	(27,414)
Deferred Revenues - Equity Return Securitization Revenue	(9,886)
Impaired Asset	92,629
Provision for Damages	(6,914)
Other (Net)	9,276
Taxable Income before State Taxes	64,447
Less : State & Local Current Tax	2,452
Federal Taxable Income	61,995
FIT on Current Year Taxable Income	13,019
Adjustment due to System Consolidation (a)	77
Tax Credits	214
NOL Reclass	(13,652)
Estimated Tax Currently Payable (b)	26,380
Adjustments of Prior Year's Accruals & Other Adjustments	(6,602)
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	19,778

(a)
Instruction 2

FOOTNOTE DATA

* The tax computation about represents an estimate of the Company's allocated portion of the Systems Consolidated Federal Income Tax. The computation of actual 2022 System Federal Income Taxes will not be available until the consolidated Federal Income Tax Return is completed and filed by October 2023. The actual consolidated group will not be available until after the consolidated Federal Income Tax Return is filed.

Name of Respondent: AEP Texas	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)	12,066,544,073	12,066,544,073					
4	Property Under Capital Leases	105,187,535.00	105,187,535.00					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,681,242,404.00	1,681,242,404.00					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	13,852,974,012	13,852,974,012					
9	Leased to Others							
10	Held for Future Use	11,917,229	11,917,229					
11	Construction Work in Progress	914,900,910	914,900,910					
12	Acquisition Adjustments	1,845,431	1,845,431					
13	Total Utility Plant (8 thru 12)	14,781,637,582	14,781,637,582					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,660,166,636.00	2,660,166,636					
15	Net Utility Plant (13 less 14)	12,121,470,946	12,121,470,946					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	2,541,905,695.00	2,541,905,695.00					
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	116,380,088	116,380,088					
22	Total in Service (18 thru 21)	2,658,285,783	2,658,285,783					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	35,422.00	35,422.00					
29	Amortization							
30	Total Held for Future Use (28 & 29)	35,422	35,422					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	1,845,431	1,845,431					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,660,166,636.00	2,660,166,636					

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent: AEP Texas	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	20,237					20,237
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	228,707,226	40,873,955	30,845,222			238,735,959
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	228,727,463	40,873,955	30,845,222			238,756,196
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights						
9	(311) Structures and Improvements						
10	(312) Boiler Plant Equipment						
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units						
13	(315) Accessory Electric Equipment						
14	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)						
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						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						
39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights	241,646,257	36,619,273	44,320			278,221,210
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	229,181,312	27,870,270	90,894			256,960,688
50	(353) Station Equipment	2,584,876,988	158,396,869	17,437,834			2,725,836,023
51	(354) Towers and Fixtures	95,331,746	23,382				95,355,128
52	(355) Poles and Fixtures	1,977,541,758	225,567,635	21,290,202			2,181,819,191
53	(356) Overhead Conductors and Devices	1,128,080,932	83,855,554	3,116,905			1,208,819,581
54	(357) Underground Conduit	39,384,395	6,951,129	255,768			46,079,756
55	(358) Underground Conductors and Devices	30,327,606	444,651	764,299			30,007,958
56	(359) Roads and Trails	54,376					54,376
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	6,326,425,370	539,728,763	43,000,222			6,823,153,911
59	4. Distribution Plant						
60	(360) Land and Land Rights	38,852,148	4,506,735				43,358,883
61	(361) Structures and Improvements	83,255,527	6,681,922	613,208			89,324,241
62	(362) Station Equipment	883,964,982	71,459,312	8,354,079			947,070,215
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	1,120,612,446	117,823,625	12,367,851			1,226,068,220
65	(365) Overhead Conductors and Devices	999,248,493	116,663,070	10,752,144			1,105,159,419
66	(366) Underground Conduit	114,873,649	12,425,848	16,983			127,282,514
67	(367) Underground Conductors and Devices	467,913,292	40,775,212	1,615,073			507,073,431
68	(368) Line Transformers	858,179,414	100,315,592	18,547,324			939,947,682
69	(369) Services	389,433,840	28,696,877	1,691,562			416,439,155
70	(370) Meters	204,784,037	22,243,667	17,378,401			209,649,303
71	(371) Installations on Customer Premises	72,950,779	2,534,786	889,603			74,595,962
72	(372) Leased Property on Customer Premises	86,896					86,896
73	(373) Street Lighting and Signal Systems	130,541,635	15,864,240	3,864,625			142,541,250
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,364,697,138	539,990,886	76,090,853			5,828,597,171
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
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	23,032,495	9,273,554	49,980			32,256,069
87	(390) Structures and Improvements	384,443,961	77,618,035	6,593,664			455,468,332
88	(391) Office Furniture and Equipment	7,797,067	4,891,166	71,340			12,616,893
89	(392) Transportation Equipment	185,606		185,606			
90	(393) Stores Equipment	2,647,349	212,013				2,859,362
91	(394) Tools, Shop and Garage Equipment	65,627,384	4,210,562	143,901			69,694,045
92	(395) Laboratory Equipment	440,894	21,070				461,964
93	(396) Power Operated Equipment	21,803					21,803
94	(397) Communication Equipment	246,560,127	28,197,727	2,800,535			271,957,319
95	(398) Miscellaneous Equipment	8,591,792	2,212,509	169,032			10,635,269
96	SUBTOTAL (Enter Total of lines 86 thru 95)	739,348,478	126,636,636	10,014,058			855,971,056
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	1,281,229	65,940	39,026			1,308,143
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	740,629,707	126,702,576	10,053,084			857,279,199
100	TOTAL (Accounts 101 and 106)	12,660,479,678	1,247,296,180	159,989,381			13,747,786,477
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	12,660,479,678	1,247,296,180	159,989,381			13,747,786,477
	Page 204-207						

Name of Respondent: AEP Texas	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 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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43						

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)
44						
45						
46						
47	TOTAL					

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Name of Respondent: AEP Texas	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 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	Wisconsin Station,Hidalgo County, TX	12/01/2023	12/31/2025	2,355,084.00
3	5 acres (1217)			
4	Cruce 345kV Station,Jim Hogg County, TX	09/01/2023	12/31/2025	2,087,210
5	77.042 acres (5313)			
6	Mangana Hein 138kV Station, Webb County, TX	12/01/2023	12/31/2025	1,948,949
7	6.3 acres (5315)			
8	Victoria Service Center ,Victoria County, TX	12/01/2023	12/31/2025	1,665,154
9	34.761 acres (B0663)			
10	Oso Creek 138kV Station, Nueces County, TX 5 acres (5328)	12/01/2023	12/31/2025	551,057
11	Buddy Owens 138kV Station,Hidalgo County, TX	12/01/2023	12/31/2025	1,302,339
12	4.899 acres (5327)			
13	Gibson 138kV Station, Taylor County, TX	12/01/2023	12/31/2025	569,933
14	3.825 acres (1019)			
15				
16				
17				
18				
19				
20				
21				
22				
21	Other Property:			
22	Crowell Telecom Site, Foard County, TX	07/01/2023	12/31/2025	459,298
23	6.90 acres (T201)			
24	Uribe 138kV Station, Zapata County, TX	12/01/2023	12/31/2025	410,344
25	10 acres (5387)			
26	Edna 138/12KV Substation, Jackson County, TX	12/01/2023	12/31/2025	305,199
27	4.984 acres (3039)			
28	Items under $250,000			262,662
29	Other Property:			
47	TOTAL			11,917,229

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

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	(TCC) Del Sol - Frontera: CI	9,198,782
2	2021 Spare Skid &Transformers	7,047,324
3	ADMS Imp DSN DNEX-TXC D	9,359,884
4	ADMS Imp DSN DNEX-TXN D	2,060,861
5	AEP Texas - TCC Fiber Offices	3,256,375
6	AEP Texas - TNC Fiber 2020	3,868,761
7	AEP TX North T CI	1,688,915
8	AEPTC Trans Pre Eng Parent	4,297,917
9	AEPTC-D Telecom	2,264,110
10	AEPTN Trans Pre Eng Parent	2,248,194
11	AEPTN Trans Pre Eng Parent	8,008,397
12	AEPTN-D Telecom	3,460,665
13	Albany-Throckmorton 69 kV CI	26,534,881
14	Angstrom-Naismith 345 kV CI	37,728,947
15	Arroyo Solar CI	6,416,633
16	Ballinger-Eden Taps CI	3,491,933
17	Barrilla 69 kV Loop Rebuild CI	1,772,868
18	Belknap - Ft. Griffin 69kV CI	18,449,627
19	Burma-Sterling City 69 kV CI	17,481,653
20	Cenizo to Cruce 345 kV: TCC CI	1,885,437
21	Charger Interconnection	14,004,531
22	CI for Tulsita Interconnection	1,373,427
23	CIS-Common Deployment-TXC D	8,089,999
24	CIS-Common Deployment-TXN D	1,784,060
25	Coleto creek - Kenedy SS Rehab	8,178,806
26	Corp Prgrm Billing-AEPTC Trans	5,202,682
27	Corp Prgrm Billing-AEPTN Trans	2,784,455
28	Corpus C Bay T 2023 TTMP CI	2,548,730
29	Corpus Phase 3 D Station	3,360,597
30	Crowell - Lake Pauline CI	1,213,940
31	Cruce to Reforzar AEP TX:CI	1,337,679
32	D/TC/Capital Blanket - TCC	5,432,645
33	DACR Mobile Transformer	1,888,055
34	Devine D-Station	6,066,557
35	Distribution CI	3,190,526
36	Escondido - Hamilton Road CI	1,743,693
37	EV Chargers for GL BU 119	1,041,843
38	Eval BESS CI	2,623,710
39	Fincas - D-Station	2,662,493
40	Fincas - T-Line	1,114,664
41	Hamilton Rd- Maxwell 138 kV CI	1,114,054

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
42	James Rowe Sub - D-Station	10,854,737
43	James Rowe Sub - T-Line	1,053,894
44	James Rowe Sub - T-Station	2,599,560
45	Kiskadee Storage CI	2,268,621
46	Laredo Pl -Universiy: Rebuild	4,349,514
47	Lunis Creek Solar CI	4,060,049
48	Mason to Mason Switch: CI	8,284,765
49	Mathis Sub - D-Station	5,842,838
50	Mathis Sub - T-Station	4,782,438
51	N. Laredo SW-Lardo VFT Rebuild	4,912,281
52	Naismith-Resnik CI	18,202,988
53	North Ed 138 fault duty CI	5,435,155
54	North Ed 345 add new rung CI	2,458,695
55	Ozona Station Re-Build CI	3,875,705
56	Ozona Station: D Underbuild CI	1,102,672
57	Pleasanton-Three Rivers 138kV	1,733,615
58	Port Isabel GIS - D-Station	3,980,794
59	Port Lavaca Area	5,132,750
60	Portilla Sub - T-Line	1,442,021
61	Portilla Sub- Dstation	1,537,220
62	Quanah Station Rebuild CI	1,688,513
63	RGV Phase 4 D Station	4,216,672
64	Roby - Rotan 69 kV line: CI	2,417,358
65	S.A. North T 2023 TTMP CI	5,076,228
66	S.A. South T 2023 TTMP CI	3,457,415
67	SAPS - Red Creek: Trans CI	2,097,756
68	Smith - Mathis 69kV Rebuild	6,043,654
69	South Abilene-Putnam 138 kV CI	12,151,942
70	SP Peregrine Interconnection	19,201,976
71	SPI - GIS - D-Station	4,094,952
72	SS-CI-CPLCo-D GEN PLT	2,500,906
73	SS-CI-WTUCo-D GEN PLT	1,139,790
74	Station Dist ribution CI	3,101,402
75	T/TC/Capital Blanket - TCC	4,920,555
76	T/TCC/NERC Physical Security	5,358,249
77	T/TNC/NERC Physical Security	1,409,131
78	TCC Cap Bank Replacements CI	1,354,765
79	TCC HCP	1,049,081
80	TCC Lon Hill to Warburton	1,334,986
81	TCC Major Eq/Spares- Distr	1,323,989
82	TCC T TTMP 2024 CI	4,083,270
83	TCC Transmission CI	1,998,537
84	TCC Transmission Work	7,025,041
85	TCC Transmission Work	4,242,731
86	TCC Transmission Work	44,013,436
87	TCC Transmission Work	8,551,381
88	TCC Transmission Work	1,902,123
89	TCC Transmission Work	20,623,951
90	TCC Transmission Work	1,434,249
91	TCC Transmission Work	1,069,106

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
92	TCC Transmission Work CI	6,070,790
93	TCC Transmission Work LNG Proj	(5,470,846)
94	TCC WHITEPOINT REHAB	6,984,507
95	TCC Work	5,320,424
96	TCC work Ang-Grissom	50,942,090
97	TCC-D Spare/Major Equipment CI	7,973,969
98	TCC-T BlnktProj Under $3M	9,185,691
99	TCC-T Spare/Major Equip CI	2,447,050
100	TC-Customer Service Blkt	(10,520,147)
101	TC-Reliability Improvement Blk	12,631,927
102	TC-Service Restoration Blkt	4,957,222
103	TC-Small Capacity Blkt	4,213,662
104	TC-Third Party Requests Blkt	1,301,744
105	TNC Abilene N T 2023 TTMP CI	2,943,686
106	TNC Abilene S T 2023 TTMP CI	4,309,195
107	TNC Cap Bank Replacements CI	2,465,214
108	TNC Live Oak to Sonora	5,288,492
109	TNC Major Eq/Spares-Trans	3,545,364
110	TNC Mason to North Brady	21,365,174
111	TNC Munday East T 2023 TTMP CI	5,003,299
112	TNC T TTMP 2024 CI	2,471,376
113	TNC Transmission	9,617,493
114	TNC Transmission CI	9,655,665
115	TNC Transmission CI	14,895,245
116	TNC Transmission CI	1,010,380
117	TNC Transmission CI	21,872,137
118	TNC Transmission CI	2,415,307
119	TNC Transmission Work	2,174,203
120	TNC Transmission Work	10,400,438
121	TNC Transmission Work	30,748,709
122	TNC Transmission Work	9,454,429
123	TNC Transmission Work	1,926,178
124	TNC-D Spare/Major Equipment CI	1,582,734
125	TNC-T Spare/Major Equipment CI	3,502,629
126	TNC-T-BlnktProj Under $3M	7,069,449
127	TN-Customer Service Blkt	1,323,842
128	TN-Reliability Improvement Blk	3,520,139
129	Transmission CI	2,645,608
130	Transmission Work	2,721,394
131	Trasnmission CI	1,230,341
132	TxDot-Loop 20 Relocation	1,431,865
133	Winecup Substation - D-Station	2,886,784
134	Winecup Substation - T-Station	1,077,615
135	Other Minor Projects Under $1,000,000	108,235,676
43	Total	914,900,910

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

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	2,397,623,821	2,397,623,823	(2)	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	338,678,131	338,677,868	263	
4	(403.1) Depreciation Expense for Asset Retirement Costs	38,964	38,964		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	(4,066,543)	[(a)](4,066,543)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	334,650,552	334,650,289	263	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(129,144,158)	(129,144,158)		
13	Cost of Removal	(74,255,805)	[(b)](74,255,805)		
14	Salvage (Credit)	13,066,705	13,066,705		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(190,333,258)	(190,333,258)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	2	(35,159)	35,161	
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,541,941,117	2,541,905,695	35,422	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production	466,713	466,713		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	912,082,627	912,082,364	263	
26	Distribution	1,469,488,789	1,469,488,789		
27	Regional Transmission and Market Operation				
28	General	159,902,988	159,867,829	35,159	
29	TOTAL (Enter Total of lines 20 thru 28)	2,541,941,117	2,541,905,695	35,422	

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FOOTNOTE DATA

(a) Concept: OtherAccounts

Depreciation expense on meters replaced by AMI meters	$(6,643,630)
Amortization of capitalized incentives	$824,573
Amortization of vegetation	$1,149,048
Amortization of capitalized SERP	$11,484
Amortization of plant disallowance	$591,978
AMS regulatory asset over/under	$4
Total	(4,066,543)

(b) Concept: CostOfRemovalOfPlant

Includes $3,575,819 of removal cost in retirement work in progress (RWIP).

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	AEP Texas Central Transition Funding, LLC.	02/01/2002		4,499,680			4,499,680	
2	AEP Texas Central Transition Funding II, LLC.	10/01/2006		10,040,226			10,040,226	
3	AEP Texas Central Transition Funding III, LLC.	02/01/2012		4,255,479	191,280		4,446,759	
4	AEP TX Restoration Funding LLC	09/01/2019		1,188,727	44,411		1,233,138	
5	AEP Texas North Generation Company, LLC	08/01/2006		6,298,617	71,758		6,370,375	
42	Total Cost of Account 123.1 $		Total	26,282,729	307,449		26,590,178	

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MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			Electric
2	Fuel Stock Expenses Undistributed (Account 152)			Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	135,489,936	186,298,032	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	7,528	0	Electric
8	Transmission Plant (Estimated)	401,565	855,386	Electric
9	Distribution Plant (Estimated)	2,045,219	2,300,442	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	825,795	[(a)]931,956	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	138,770,043	190,385,816	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	138,770,043	190,385,816	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

This footnote applies to both current and prior year.

Assigned to - Other: Includes Customer Accounts and Administrative and General Expenses.

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
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												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												

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)
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
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												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												

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)
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

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

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	[(a)] 17INR0043	213	186		
3	18INR0058	13,225	186		
4	19INR0022	14,571	186	70,000	186
5	19INR0035	7,948	186		
6	19INR0171	17,343	186		
7	19INR0177	31,559	186		
8	20AEPSC001	320	186		
9	20INR0013	68	186		
10	20INR0016	51	186		
11	20INR0053	377	186		
12	20INR0054	63,067	186		
13	20INR0070	50,370	186		
14	20INR0086	11,746	186		
15	20INR0097	150,763	186	76,000	186
16	20INR0128	38,440	186		
17	20INR0129	68	186		
18	20INR0213	643	186		
19	20INR0232	51	186		
20	20INR0249	59,259	186		
21	20INR0279	52,168	186		
22	20INR0283	38,524	186		
23	21INR0223	15,125	186	80,000	186
24	21INR0253	13,275	186	80,000	186
25	21INR0314	72	186		
26	21INR0344	540	186		
27	21INR0346	2,466	186		
28	21INR0356	613	186		
29	21INR0440	146	186		
30	21INR0454	480	186		
31	21INR0467	83,510	186		
32	21INR0495	484	186		
33	21INR0499	29,855	186		
34	22INR0272	51	186		
35	22INR0275	1,651	186		
36	22INR0283	824	186		
37	22INR0337	213	186		
38	22INR0349	183	186	20,000	186
39	22INR0352	49,409	186		

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
40	22INR0353	(76,069)	186	10,000	186
41	22INR0365	409	186		
42	22INR0387	2,175	186		
43	22INR0390	51	186		
44	22INR0392	469	186		
45	22INR0397	986	186		
46	22INR0401	3,428	186		
47	22INR0445	1,270	186		
48	22INR0446	2,468	186		
49	22INR0455	21,613	186		
50	22INR0469	16,124	186		
51	22INR0559	10,378	186		
52	23INR0047	1,270	186		
53	23INR0061	4,105	186		
54	23INR0062	1,743	186		
55	23INR0087	8,610	186		
56	23INR0090	714	186		
57	23INR0093	28,856	186		
58	23INR0100	5,621	186		
59	23INR0116	5,736	186		
60	23INR0117	3,689	186		
61	23INR0123	18,545	186		
62	23INR0132	9,919	186		
63	23INR0134	2,605	186		
64	23INR0177	350	186		
65	23INR0180	117,393	186		
66	23INR0204	16,156	186		
67	23INR0206	1,229	186		
68	23INR0223	20,878	186		
69	23INR0284	1,475	186		
70	23INR0351	30,355	186		
71	23INR0354	14,407	186		
72	23INR0361	2,337	186		
73	23INR0373	27,396	186		
74	23INR0374	16,749	186		
75	23INR0388	19,333	186		
76	23INR0408	51	186		
77	23INR0443	28,332	186		
78	23INR0472	107,746	186	80,000	186
79	23INR0496	698	186		
80	23INR0497	552	186		
81	24INR0020	21,867	186		
82	24INR0048	830	186	80,000	186
83	24INR0066	137	186		
84	24INR0068	19,938	186		
85	24INR0078	11,966	186		
86	24INR0088	3,756	186		
87	24INR0158	14,636	186		
88	24INR0162	5,672	186		
89	24INR0168	18,422	186		

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
90	24INR0183			80,000	186
91	24INR0197	3,277	186		
92	24INR0201	487	186	80,000	186
93	24INR0260	15,964	186		
94	24INR0272	21,465	186		
95	24INR0280			80,000	186
96	24INR0294	3,683	186		
97	24INR0302	7,244	186		
98	24INR0319	146	186	80,000	186
99	24INR0378	2,890	186		
100	24INR0379	2,066	186		
101	24INR0381	3,018	186		
102	24INR0403	2,131	186	80,000	186
103	24INR0425	1,382	186	80,000	186
104	24INR0436	20,106	186		
105	24INR0491			80,000	186
106	24INR0557			80,000	186
107	24INR0558			80,000	186
108	24INR0572	1,095	186	80,000	186
109	24INR0617			80,000	186
110	25INR0012	255	186		
111	25INR0022	818	186		
112	25INR0039	1,442	186		
113	25INR0040	70	186	80,000	186
114	25INR0052	12,646	186		
115	25INR0060	17,252	186		
116	25INR0076	17,381	186		
117	25INR0078	1,751	186		
118	25INR0081	10,599	186		
119	25INR0109	18,808	186		
120	25INR0110	2,814	186		
121	25INR0112			80,000	186
122	25INR0133			80,000	186
123	25INR0150	3,056	186		
124	25INR0160	18,048	186		
125	25INR0192	17,262	186		
126	25INR0222	20,020	186		
127	25INR0232	146	186	80,000	186
128	25INR0250	366	186	80,000	186
129	25INR0270 & 25INR0552			80,000	186
130	25INR0271			80,000	186
131	25INR0304	1,059	186	80,000	186
132	25INR0319			80,000	186
133	25INR0321	2,066	186	100,000	186
134	25INR0329	1,496	186	80,000	186
135	25INR0375			80,000	186
136	25INR0379	538	186	80,000	186
137	25INR0386	1,473	186	80,000	186
138	25INR0394			80,000	186
139	25INR0419	1,221	186	80,000	186

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
140	25INR0441	708	186	80,000	186
141	25INR0501			80,000	186
142	25INR0541			80,000	186
143	25INR0544			80,000	186
144	26INR0021	941	186	80,000	186
145	26INR0028	941	186	80,000	186
146	26INR0034			80,000	186
147	26INR0076			80,000	186
148	26INR0083	1,068	186	80,000	186
149	26INR0112	323	186	80,000	186
150	26INR0116	757	186	80,000	186
151	26INR0134 & 26INR0135			80,000	186
152	26INR0146 & 26INR0148			80,000	186
153	26INR0153 & 26INR0164	956	186	80,000	186
154	26INR0155 & 26INR0156			80,000	186
155	26INR0195 & 26INR0196			80,000	186
156	26INR0218			80,000	186
157	27INR0015	1,681	186	80,000	186
158	27INR0047 & 27INR0048			80,000	186
159	27INR0083			80,000	186
160	28INR0008 & 28INR0009			80,000	186
20	Total	1,569,963		4,356,000	
21	**Generation Studies**				
39	Total				
40	Grand Total	1,569,963		4,356,000	

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Name of Respondent: AEP Texas	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: DescriptionOfStudyPerformed
Respondent is unable to expand on the description due to Electric Reliability Council of Texas (ERCOT) disclosure limitations when studies are in process.

Name of Respondent: AEP Texas	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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Advanced Metering Systems Existing Meter Investment of "old meters retired" and replaced by "Advanced Meters", PUCT Docket #36928	16,047,606		403	6,643,630	9,403,976
2	Defd Mobile Gen Lease Payment and Unrecognized Equity Mobile Gen	17,598,642	30,089,612	182, 431	14,282,685	33,405,569
3	Deferred Incremental Expense as it Relates to Covid-19	3,810,023	17,938,769	182, 921, 923, 905	19,261,925	2,486,867
4	Deferred interim LOAD-MGMT PRG	110,000				110,000
5	Distribution Vegetation Estimate, PUCT Docket #49494 - Rate Case	17,290,698	(1)	407	5,311,926	11,978,771
6	Other Regulatory Assets	1,825,933	5	253	5	1,825,933
7	Over Refunded AEPTX ITR Rider	1,663,907				1,663,907
8	Power of Texas Holdings	4,092,318	45,032	131	96,164	4,041,186
9	Reserve for Catastrophe for storm recovery. Currently funded at an annual rate of $4.2M per year., PUCT Docket #49494	35,239,173	17,955,145	593	11,184,317	42,010,001
10	SFAS 106 Medicare Subsidy, Amortization Period: 01/2013 - 12/2024	1,392,522		926	696,261	696,261
11	SFAS 109 Deferred FIT	34,587,599	9,654,260	190	2,909,654	41,332,205
12	SFAS 109 Deferred SIT	36,461,960	7,926,618	283	2,891,588	41,496,990
13	SFAS 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	173,270,283	189,851,436	129	179,881,701	183,240,018
14	TX Line Inspection Costs	4,483,202	1,230,431	182, 571	4,778	5,708,855
15	Under-recovery of Energy Efficiency Program Expenses, PUCT Docket (updated annually)	11,867,295	22,945,313	456, 907	25,575,413	9,237,195
16	Under-recovery of Transmission Cost Recovery Factor, PUCT Dockey (updated semiannually)	3,834,366	38,455,562	254, 565	42,289,928	
17	Various Rate Case Expenses Pending	25,839	486,829			512,668
18	Wholesale Distribution Substation Service - Oncor	1,452,740	3,580,500			5,033,240
19	Unrealized Losses on Forward Commitments		223,204	244	9,446	213,758
20	Circuit Segmentation Study		7,558			7,558
44	TOTAL	365,054,106	340,390,273		311,039,421	394,404,958

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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)	Credits Amount (e)
1	Associated Business Development	1,563,774	43,549,737	146/154/163/184/186/234/236/253/408/560/561/562/565/566/570/583/588/592/922/924/925/935	43,527,365
2	Unamortized Credit Line Fees Amortization period through 6/1/2022	826,913	230,124	431	392,529
3	Deferred Lease Assets	434,152	2,014,651	184/234/242	1,783,551
4	Minor Items <$100,000 or 1%"	(12,472)	13,000	152/183/186/500/501/506/510/512/513/514/517/524/528/530/539/566/588/557/545	5,887
5	Deferred Expenses	2,833	1,067,893	921	1,009,197
47	Miscellaneous Work in Progress				
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)				
49	TOTAL	2,815,199			

Line No.	Balance at End of Year (f)
1	1,586,146
2	664,508
3	665,252
4	(5,359)
5	61,529
47	
48	
49	2,972,076

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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	ACRS BENEFIT NORMALIZED	7,527,030	7,850,453
3	BOOK OPERATING LEASE	20,254,715	16,720,188
4	O/U RECOVERY SECURITIZATION REVENUE	5,445,971	5,303,561
5	DISALLOWED COSTS-TX DIST VEG MGT CST	16,146,225	10,432,893
6	ACCRUED BOOK VACATION PAY	2,867,392	3,001,195
7	Other	1,173,954	7,540,125
8	TOTAL Electric (Enter Total of lines 2 thru 7)	53,415,287	50,848,415
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	123,395,558	122,603,352
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	176,810,845	173,451,767

Notes

Name of Respondent: AEP Texas	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)									
3	Total					1				
4	Preferred Stock (Account 204)									
5										
6										
7										
8	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

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Other Paid-in Capital

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

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

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	1,554,164,804
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	525,000,000
4	Ending Balance Amount	2,079,164,804
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	(217,010)
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	(217,010)
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	4,330,402
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	(3,607,050)
16	Ending Balance Amount	723,351
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	2,079,671,145

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

CAPITAL STOCK EXPENSE (Account 214)

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

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

Name of Respondent: AEP Texas	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	Series 2001A, 6.3% - (Matagorda)		100,635,000					07/01/2009	11/01/2029	07/01/2009	11/01/2029
18	Series 2005A, 4.4% - (Matagorda)		111,700,000					12/06/2006	05/01/2030	03/16/2005	05/01/2030
19	Series 2005B, 4.55% - (Matagorda)		50,000,000					12/06/2006	05/01/2030	03/16/2005	05/01/2030
20	Series 2008 - 1&2, Matagorda Remarketing, 4.0% (Issued 6-3-2013)		120,265,000					06/03/2013	06/01/2030	06/03/2013	06/01/2030
21	Series 1996, 0.90% - Matagorda Pollution Control Bonds		60,000,000					09/01/2020	09/01/2023	09/01/2020	09/01/2023
22	Series 1996 4.25% (Matagorda)		60,000,000					09/01/2023	05/01/2030	09/01/2023	05/01/2030
23	Private Placement Notes:										
24	Series B, 6.76%		1,600,000					04/01/2008	04/01/2038	04/01/2008	04/01/2038
25	Series B, 6.76 %		12,700,000					04/01/2008	04/01/2038	04/01/2008	04/01/2038
26	Series B, 6.76%		13,700,000					04/01/2008	04/01/2038	04/01/2008	04/01/2038
27	Series B , 6.76%		35,000,000					04/01/2008	04/01/2038	04/01/2008	04/01/2038
28	Series B , 6.76%		7,000,000					04/01/2008	04/01/2038	04/01/2008	04/01/2038
29	Other Long-Term Debt:										
30	Goodfellow Air Force Base - 4.5%		1,001,187					12/01/2009	11/01/2059	12/01/2009	11/01/2059
31	Texas Local Revolving Credit Facility		200,000,000					05/03/2022	05/03/2025	05/03/2022	05/03/2025
32	Senior Unsecured Notes:										
33	Series C, 3.09%		125,000,000		597,741			02/28/2013	02/28/2023	02/28/2013	02/28/2023
34	Series C - Financial Hedges										
35	Series D, 4.48%		75,000,000		358,644			02/27/2013	02/27/2043	02/27/2013	02/27/2043

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)
36	Series E, 3.27%										
37	Series F, 3.75%		50,000,000		252,928			09/30/2015	09/30/2025	09/30/2015	09/30/2025
38	Series G, 4.71%		50,000,000		252,928			12/15/2015	12/15/2035	12/15/2015	12/15/2035
39	Series E (formerly B) 6.65% Notes		275,000,000		2,504,241		1,342,000	02/18/2003	02/15/2033	03/01/2003	02/15/2033
40	Series B, 3.81%		50,000,000					04/30/2014	04/30/2026	04/30/2014	04/30/2026
41	Series C, 4.67%		100,000,000					04/30/2014	04/30/2044	04/30/2014	04/30/2044
42	Series D, 4.77%		100,000,000		1,454,317			10/30/2014	10/30/2044	10/30/2014	10/30/2044
43	Series G, 3.85%		250,000,000		1,864,770		2,447,500	09/18/2015	10/01/2025	09/18/2015	10/01/2025
44	Series A, 2.4% (FERC Authority ES16-47-000)										
45	Series B, 3.8%		300,000,000		3,129,449		3,450,000	09/22/2017	10/01/2047	09/22/2017	10/01/2047
46	Series E, 3.95% (FERC Authority ES18-22-000)		500,000,000		3,922,721		1,650,000	05/17/2018	06/01/2028	05/17/2018	06/01/2028
47	Series G, 4.15%		300,000,000		2,625,000		3,264,120	05/01/2019	05/01/2049	05/01/2019	05/01/2049
48	Series H, 3.45%		450,000,000		3,937,500		2,106,000	12/31/2019	01/31/2050	12/31/2019	01/31/2050
49	Series I, 2.10%		600,000,000		4,860,880			07/01/2020	07/01/2030	07/01/2020	07/01/2030
50	Series J, 3.45%		450,000,000		3,946,680		1,341,000	05/06/2021	05/15/2051	05/06/2021	05/15/2051
51	Series K, 4.70%		500,000,000		4,137,633		1,420,000	05/18/2022	05/17/2032	05/18/2022	05/17/2032
52	Series L, 5.25%		500,000,000		5,262,633		820,000	05/18/2022	05/17/2052	05/18/2022	05/17/2052
53	Series M, 5.40%		450,000,000		3,624,795		729,000	05/24/2023	06/01/2033	05/24/2023	06/01/2033
54	Subtotal		5,898,601,187		42,732,859		18,569,620				
33	TOTAL		5,898,601,187								

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	100,635,000	2,616,510
18	111,700,000	4,914,800
19	50,000,000	2,275,000
20	120,265,000	4,810,600
21		360,000
22	60,000,000	850,000
23		
24	1,600,000	108,160
25	12,700,000	858,520
26	13,700,000	926,120
27	35,000,000	2,366,000
28	7,000,000	473,200
29		
30	901,510	40,810
31	200,000,000	12,934,998
32		
33		611,563
34		(114)
35	75,000,000	3,360,000
36		
37	50,000,000	1,875,000
38	50,000,000	2,355,000
39	275,000,000	18,287,500
40	50,000,000	1,905,000
41	100,000,000	4,670,000
42	100,000,000	4,770,000
43	250,000,000	9,625,000
44		
45	300,000,000	11,400,000
46	500,000,000	19,750,000
47	300,000,000	12,450,000
48	450,000,000	15,525,000
49	600,000,000	12,600,000

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
50	450,000,000	15,525,000
51	500,000,000	23,500,000
52	500,000,000	26,250,000
53	450,000,000	14,647,500
54	5,713,501,510	232,641,166
33	5,713,501,510	232,641,166

Name of Respondent: AEP Texas	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)	[a]370,442,506
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	61,994,741
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		

Line No.	Particulars (Details) (a)	Amount (b)
40		
41		
42		
43		
44		
Page 261		

FOOTNOTE DATA

(a) Concept: NetIncomeLoss

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

FOOTNOTE DATA

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

Net Income for the Year per Page 117	370,443
Federal & State Income Taxes	85,894
Pre-Tax Book Income	456,337
AFUDC / Interest Capitalized	(20,202)
Asset Retirement Obligation	502
Capitalized Relocation Costs	(7,236)
Deferred Intercompany Tax Gain	143
Misc Overheads Capitalized	—
Excess Tax Vs Book Depreciation	(335,061)
Book Accruals	(10,693)
Removal Costs	(68,851)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)	(7,904)
Provision for Possible Revenue Refund	(277)
Book Reserves	(27,414)
Deferred Revenues - Equity Return Securitization Revenue	(9,886)
Impaired Asset	92,629
Provision for Damages	(6,914)
Other (Net)	9,276
Taxable Income before State Taxes	64,447
Less : State & Local Current Tax	2,452
Federal Taxable Income	61,995
FIT on Current Year Taxable Income	13,019
Adjustment due to System Consolidation (a)	77
Tax Credits	214
NOL Reclass	(13,652)
Estimated Tax Currently Payable (b)	26,380
Adjustments of Prior Year's Accruals & Other Adjustments	(6,602)
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	19,778

(a)
Instruction 2

FOOTNOTE DATA

* The tax computation about represents an estimate of the Company's allocated portion of the Systems Consolidated Federal Income Tax. The computation of actual 2022 System Federal Income Taxes will not be available until the consolidated Federal Income Tax Return is completed and filed by October 2023. The actual consolidated group will not be available until after the consolidated Federal Income Tax Return is filed.

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

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)
1	Federal Tax	Federal Tax			(12,675,481)	0	23,385,305	14,974,006		(4,264,182)	
2					0	0				0	
3	**Subtotal Federal Tax**				(12,675,481)	0	23,385,305	14,974,006	0	(4,264,182)	0
4	State Tax	State Tax			0	0				0	
5					0	0				0	
6	**Subtotal State Tax**				0	0	0	0	0	0	0
7	Local Tax	Local Tax		2019	(1,835,151)	0				(1,835,151)	
8	Local Tax	Local Tax	TX	2021	0	0				0	
9	Local Tax	Local Tax	TX	2022	4,307,279	0	(59,495)	4,247,784		0	
10	Local Tax	Local Tax	TX	2023	0	0	53,359,915	49,644,563		3,715,352	
11	**Subtotal Local Tax**				2,472,128	0	53,300,420	53,892,347	0	1,880,201	0
12	**Subtotal Other Tax**				0	0	0	0	0	0	0
13	Personal Property Lea	Property Tax	TX	2022	1,660,427	0	(75,047)	1,585,380		0	
14	Personal Property Lea	Property Tax	TX	2023	0	0	1,975,000	243,355		1,731,645	
15	Real & Pers Prop	Property Tax	TX	2021	0	0	(579)	(579)		0	
16	Real & Pers Prop	Property Tax	TX	2022	80,417,007	0	964,275	81,381,282		0	
17	Real & Pers Prop	Property Tax	TX	2023	0	0	102,309,000	17,881,243		84,427,757	
18	**Subtotal Property Tax**				82,077,434	0	105,172,649	101,090,681	0	86,159,402	0
19		Real Estate Tax			0	0				0	
20	**Subtotal Real Estate Tax**				0	0	0	0	0	0	0
21	FEDERAL UNEMPLOYMENT 2023	Unemployment Tax		2023	10,572		83,021	75,494	0	18,099	
22	STATE UNEMPLOYMENT 2023	Unemployment Tax	LA	2023	0		0	0	0	0	
23	STATE UNEMPLOYMENT 2023	Unemployment Tax	OK	2023	0		0	0	0	0	
24	STATE UNEMPLOYMENT 2023	Unemployment Tax	TX	2023	18,840		85,275	85,699	0	18,416	
25	**Subtotal Unemployment Tax**				29,412	0	168,296	161,193	0	36,515	0
26	Sales And Use Tax	Sales And Use Tax	TX	2021	0	0				0	
27	Sales And Use Tax	Sales And Use Tax	TX	2022	3,440,868	0	(306,481)	3,134,387		0	
28	Sales And Use Tax	Sales And Use Tax	TX	2023	0	0	37,463,822	36,077,484		1,386,338	
29	**Subtotal Sales And Use Tax**				3,440,868	0	37,157,341	39,211,871	0	1,386,338	0
30	State Tax	Income Tax	MULTI	2019	1,835,151	0				1,835,151	
31	State Tax	Income Tax	NC	2022	0	0		700		(700)	
32	State Tax	Income Tax	TX	2011	(30,203)	0				(30,203)	
33	State Tax	Income Tax	TX	2017	0	0				0	
34	State Tax	Income Tax	TX	2018	(1,581,821)	0				(1,581,821)	
35	State Tax	Income Tax	TX	2019	3,251,272	0				3,251,272	

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)
36	State Tax	Income Tax	TX	2020	(2,555,280)	0				(2,555,280)	
37	State Tax	Income Tax	TX	2021	1,097,948	0				1,097,948	
38	State Tax	Income Tax	TX	2022	2,151,499	0				2,151,499	
39	State Tax	Income Tax	TX	2023	0	0	2,742,829			2,742,829	
40	State Tax	Income Tax	FIN48	2022	0	0				0	
41	**Subtotal Income Tax**				4,168,566	0	2,742,829	700	0	6,910,695	0
42	**Subtotal Excise Tax**				0	0	0	0	0	0	0
43	**Subtotal Fuel Tax**				0	0	0	0	0	0	0
44	FICA 2023	Federal Insurance Tax			1,490,067	0	13,245,933	13,901,847	0	834,153	
45	**Subtotal Federal Insurance Tax**				1,490,067	0	13,245,933	13,901,847	0	834,153	0
46	**Subtotal Franchise Tax**				0	0	0	0	0	0	0
47	State Franchise Tax	Miscellaneous Other Tax	NC	2022	0	0	200			200	
48	State Franchise Tax	Miscellaneous Other Tax	NC	2023	0	0	200			200	
49	**Subtotal Miscellaneous Other Tax**				0	0	400	0	0	400	0
50	**Subtotal Other Federal Tax**				0	0	0	0	0	0	0
51	Ohio CAT Tax	Other State Tax	OH	2022	0	0	5	5		0	0
52	Ohio CAT Tax	Other State Tax	OH	2023	0	0	13	13		0	0
53	**Subtotal Other State Tax**				0	0	18	18	0	0	0
54	**Subtotal Other Property Tax**				0	0	0	0	0	0	0
55	**Subtotal Other Use Tax**				0	0	0	0	0	0	0
56	**Subtotal Other Advalorem Tax**				0	0	0	0	0	0	0
57	**Subtotal Other License And Fees Tax**				0	0	0	0	0	0	0
58	**Subtotal Payroll Tax**				0	0	0	0	0	0	0
59	**Subtotal Advalorem Tax**				0	0	0	0	0	0	0
60	**Subtotal Other Allocated Tax**				0	0	0	0	0	0	0
61	**Subtotal Severance Tax**				0	0	0	0	0	0	0
62	**Subtotal Penalty Tax**				0	0	0	0	0	0	0
63	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0	0
40	TOTAL				81,002,994		235,173,191	223,232,663		92,943,522	

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	13,647,317			9,737,988
2				
3	13,647,317	0	0	9,737,988
4				
5				
6	0	0	0	0
7				
8				
9				(59,495)
10	53,300,420			59,495
11	53,300,420	0	0	0
12	0	0	0	0
13	(75,047)			
14	1,975,000			
15	(579)			
16	964,275			
17	98,902,400			3,406,600
18	101,766,049	0	0	3,406,600
19				
20	0	0	0	0
21	39,506			43,515
22	0			0
23	0			0
24	31,269			54,006
25	70,775	0	0	97,521
26				
27				(306,482)
28	(98,272)			37,562,095
29	(98,272)	0	0	37,255,613
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	2,611,971			130,860
40				
41	2,611,971	0	0	130,860
42	0	0	0	0
43	0	0	0	0
44	5,739,145			7,506,788
45	5,739,145	0	0	7,506,788
46	0	0	0	0
47	200			
48	200			

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)
49	400	0	0	0
50	0	0	0	0
51	5			
52	13			
53	18	0	0	0
54	0	0	0	0
55	0	0	0	0
56	0	0	0	0
57	0	0	0	0
58	0	0	0	0
59	0	0	0	0
60	0	0	0	0
61	0	0	0	0
62	0	0	0	0
63	0	0	0	0
40	177,037,823			58,135,370

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

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%				411.4					
3	4%				411.4					
4	7%				411.4					
5	10%	6,073,525	411.1		411.4	697,652		5,375,873	16 Years	
6	State DITC		411.1		411.4					
7	30%				411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)	6,073,525				697,652		5,375,873		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	6,073,525						5,375,873		

Name of Respondent: AEP Texas	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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Pole Attachments	5,672,207	107/108/142/143/163/172/186/421/451/454/588/589	5,639,288	7,325,012	7,357,930
2	Security Deposits	74,475,865	107/108/146/154/163/184/232/234/236/253/560/566/570/571/935/	78,076,340	55,888,011	52,287,536
3	Deferred Equity Income relating to Supreme Court of Texas July 2011 Reversal of 2006 Capacity Auction True-up Disallowance (PUCT Docket #39722)	15,996,871	456	8,208,218		7,788,653
4	Contributions in Aid of Construction	25,772,232	107/108	25,772,232	56,587,840	56,587,840
5	Associated Business Development	15,108,726	142/143/186/253/426/431	6,640,646	39,011,379	47,479,459
6	Environmental Liabilities	150,888	242/588	148,610	5,065	7,343
7	Texas Reliability Entity - Audit Assessment	2,090,427	242	200,100		1,890,327
8	Minor Items < $100,000	131,925				131,925
9	Texas Restoration Carrying Cost	7,225,179	456	994,389		6,230,790
10	Asbestos Settlement Accrual	85,466				85,466
47	TOTAL	146,709,786		125,679,822	158,817,307	179,847,270

Name of Respondent: AEP Texas	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										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
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						254		254		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	1,542,006,709	129,098,071	50,705,989					190		1,620,398,791
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,542,006,709	129,098,071	50,705,989							1,620,398,791
6	[(a)] Regulatory Assets - SFAS109	(394,187,990)					1823/254	840,516	1823/254	12,056,779	(382,971,727)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,147,818,719	129,098,071	50,705,989				840,516		12,056,779	1,237,427,064
10	Classification of TOTAL										
11	Federal Income Tax	1,147,818,719	129,098,071	50,705,989				840,516		12,056,779	1,237,427,064
12	State Income Tax										
13	Local Income Tax										

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FOOTNOTE DATA

(a) Concept: DescriptionOfNonUtilityAccountDetails

Description	Beg Bal	DR 410	CR 411	Debits	Credits	End Bal
Non-Utility	—	—	—	—	—	—
SFAS 109	(394,187,990)	—	—	840,516	12,056,779	(382,971,727)
Total	(394,187,990)	—	—	840,516	12,056,779	(382,971,727)

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Accrued Bk Pension Expense	32,555,788	581,700	120,325							33,017,163
4	Defd Tax Gain Securitized Reg	65,012,726		19,452,132							45,560,594
5	REG ASSET-SFAS 158 - PENSIONS	29,565,715	4,746,620	103,477							34,208,858
6	ACCRUED BK PENSION COSTS - SFAS 158	(29,565,715)	103,477	4,746,620							(34,208,858)
7	ACRS Benefit Normalized	21,881	10,664	18,647							13,898
8	Other	1,557,835	9,631,470	12,127,569				142,208	283		(1,080,472)
9	TOTAL Electric (Total of lines 3 thru 8)	99,148,230	15,073,931	36,568,770				142,208			77,511,183
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	74,220,850			4,170,910	41,693	1823/254	3,587,909	1823/254	11,741,036	86,503,194
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	173,369,080	15,073,931	36,568,770	4,170,910	41,693		3,730,117		11,741,036	164,014,377
20	Classification of TOTAL										
21	Federal Income Tax	136,743,345	15,021,351	36,532,493	4,170,910	41,693		1,088,251		4,331,687	122,604,856
22	State Income Tax	36,625,735	52,580	36,277				2,641,866		7,409,349	41,409,521
23	Local Income Tax										

NOTES

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Name of Respondent: AEP Texas	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	Advanced metering system-AMS	350,860		5	7,848	358,703
2	COVID-19 Energy Charges-TX	1,423,566	182	1,423,566		
3	Deferred Income Tax Adjustment - for Oncor Acquisition	160,298	407	161,695	1,117,657	1,116,260
4	Earnings Subject to Refund under State of Texas Restructuring Legislation Amortization @ 3.361% or approximately 30 years per , Docket No. 22354	4,341,619	407	496,012		3,845,607
5	SFAS 109 Deferred FIT	515,612,568	182, 190, 236, 254, 255, 282, 283, 409, 410, 411	8,354,399	581,241	507,839,410
6	TCRF Over Recovery	6,450,314	—	36,796,949	32,429,792	2,083,157
7	Transition Regulatory Liability	3,285,956	182, 431	2,214,199	59,299	1,131,056
8	Unrealized Gain/Loss on Forward Commitments	19,823	175, 182	29,269	9,446	
41	TOTAL	531,645,004		49,476,094	34,205,283	516,374,193

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

Electric Operating Revenues

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales						
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)						
5	Large (or Ind.) (See Instr. 4)						
6	(444) Public Street and Highway Lighting						
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers						
11	(447) Sales for Resale						
12	TOTAL Sales of Electricity						
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds						
15	Other Operating Revenues						
16	(450) Forfeited Discounts	22,577	144,137				
17	(451) Miscellaneous Service Revenues	3,736,674	2,531,773				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	22,627,153	17,117,784				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	1,161,018,186	1,164,380,659				
22	(456.1) Revenues from Transmission of Electricity of Others	619,029,970	563,811,742				

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)
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	1,806,434,561	1,747,986,095				
27	TOTAL Electric Operating Revenues	1,806,434,561	1,747,986,095				

Line12, column (b) includes $ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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42					

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)
43					
44					
45					
46	TOTAL				
Page 302					

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
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38						

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)
39						
40						
41	TOTAL Billed - All Accounts					
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts					
Page 304						

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SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1											
2											
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											

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)
15	Subtotal - RQ										
16	Subtotal-Non-RQ										
17	Total										
Page 310-311											

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	(9,336)	(115,943)
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	(9,336)	(115,943)
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant	(6)	6
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	(6)	6
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	(9,342)	(115,937)
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		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		(235)
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		(235)
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		(235)
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		1,000
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	77	
78	(557) Other Expenses		254
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	77	1,254
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	(9,265)	(114,918)
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	19,220,302	22,202,591
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,193,370	4,262,489
87	(561.3) Load Dispatch-Transmission Service and Scheduling	(3,277)	(8,167)
88	(561.4) Scheduling, System Control and Dispatch Services	48,567	61,626
89	(561.5) Reliability, Planning and Standards Development	640,622	595,223
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,269,276	1,197,780
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	342,886	267,633
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	368,919,673	377,302,355
97	(566) Miscellaneous Transmission Expenses	6,569,945	7,079,504
98	(567) Rents	21,235	4,087
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	402,222,599	412,965,121
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	76,753	108,866
102	(569) Maintenance of Structures	95,978	42,292
103	(569.1) Maintenance of Computer Hardware	16,799	17,703
104	(569.2) Maintenance of Computer Software	1,744,703	1,195,310
105	(569.3) Maintenance of Communication Equipment	265,047	471,469
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,351,335	4,999,287
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	13,418,716	15,347,667
109	(572) Maintenance of Underground Lines	38,966	15,470
110	(573) Maintenance of Miscellaneous Transmission Plant	9,223	19,085
111	TOTAL Maintenance (Total of Lines 101 thru 110)	21,017,520	22,217,149
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	423,240,118	435,182,270
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		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
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)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,755,972	6,899,923
135	(581) Load Dispatching	3,200,773	3,429,262
136	(582) Station Expenses	1,802,354	2,137,650
137	(583) Overhead Line Expenses	7,994,391	7,204,124
138	(584) Underground Line Expenses	3,462,325	2,972,951
138.1	(584.1) Operation of Energy Storage Equipment		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
139	(585) Street Lighting and Signal System Expenses	20,015	419,036
140	(586) Meter Expenses	11,396,592	9,470,649
141	(587) Customer Installations Expenses	1,207,392	866,225
142	(588) Miscellaneous Expenses	32,386,793	27,722,045
143	(589) Rents	5,766,249	495,320
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	72,992,856	61,617,185
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	131,287	115,808
147	(591) Maintenance of Structures	36,976	25,845
148	(592) Maintenance of Station Equipment	3,751,437	3,310,697
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	47,407,173	47,036,558
150	(594) Maintenance of Underground Lines	1,731,980	800,316
151	(595) Maintenance of Line Transformers	741,378	954,840
152	(596) Maintenance of Street Lighting and Signal Systems	537,477	670,283
153	(597) Maintenance of Meters	309,773	294,660
154	(598) Maintenance of Miscellaneous Distribution Plant	102,099	139,678
155	TOTAL Maintenance (Total of Lines 146 thru 154)	54,749,580	53,348,685
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	127,742,435	114,965,870
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	370,139	452,691
160	(902) Meter Reading Expenses	419,713	189,189
161	(903) Customer Records and Collection Expenses	11,865,792	12,087,069
162	(904) Uncollectible Accounts	926,698	35,228
163	(905) Miscellaneous Customer Accounts Expenses	252,815	83,142
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	13,835,157	12,847,319
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	17,963,275	18,843,189
168	(908) Customer Assistance Expenses	1,277,657	1,386,200
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	22,646	38,063
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	19,263,578	20,267,452
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	179,557	250,725
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	179,557	250,725
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	35,803,696	36,447,580
182	(921) Office Supplies and Expenses	1,284,094	2,958,970
183	(Less) (922) Administrative Expenses Transferred-Credit	9,732,569	10,253,829
184	(923) Outside Services Employed	1,735,610	11,885,136
185	(924) Property Insurance	6,652,760	7,031,525
186	(925) Injuries and Damages	3,843,206	2,712,879
187	(926) Employee Pensions and Benefits	(10,933,492)	(6,814,414)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,529,962	556,662
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	430,903	445,406
192	(930.2) Miscellaneous General Expenses	1,369,858	1,582,860
193	(931) Rents	1,000,259	1,360,267
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	32,984,287	47,913,042
195	Maintenance		
196	(935) Maintenance of General Plant	16,449,751	18,164,395
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	49,434,038	66,077,437
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	633,685,619	649,476,155
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Name of Respondent: AEP Texas	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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15	TOTAL						0	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				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				

Name of Respondent: AEP Texas	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	Altop Energy	Various	Various	SFP	N/A	Various	Various		68,633	68,633
2	Giddings, City of (1)	Various	Various	SFP	N/A	Various	Various			
3	Sanger, City of (1)	Various	Various	SFP	N/A	Various	Various			
4	[a] Austin Energy (1)	Various	Various	SFP	N/A	Various	Various			
5	Golden Spread Electric Cooperative, Inc (1)	Various	Various	SFP	N/A	Various	Various			
6	Schulenberg, City of (1)	Various	Various	SFP	N/A	Various	Various			
7	Bandera Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
8	Goldsmith, City of (1)	Various	Various	SFP	N/A	Various	Various			
9	Seguin, City of (1)	Various	Various	SFP	N/A	Various	Various			
10	Bartlett, City of (1)	Various	Various	SFP	N/A	Various	Various			
11	Goldthwaite, City of (1)	Various	Various	SFP	N/A	Various	Various			
12	Sempra Energy Solutions, LLC (2)	Various	Various	SFP	N/A	Various	Various		22,433	22,433
13	Bastrop, City of (1)	Various	Various	SFP	N/A	Various	Various			
14	Gonzales, City of (1)	Various	Various	SFP	N/A	Various	Various			
15	Seymour, City of (1)	Various	Various	SFP	N/A	Various	Various			
16	Bellville, City of (1)	Various	Various	SFP	N/A	Various	Various			
17	Granbury Municipal Utilities (1)	Various	Various	SFP	N/A	Various	Various			
18	Shiner, City of (1)	Various	Various	SFP	N/A	Various	Various			
19	Bluebonnet Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
20	Guadalupe Valley Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
21	Smithville, City of (1)	Various	Various	SFP	N/A	Various	Various			
22	Boerne, City of (1)	Various	Various	SFP	N/A	Various	Various			
23	Hallettsville, City of (1)	Various	Various	SFP	N/A	Various	Various			
24	South Texas Electric Cooperative, Inc (1)	Various	Various	SFP	N/A	Various	Various			
25	Brady, City of (1)	Various	Various	SFP	N/A	Various	Various			
26	Hamilton County Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
27	Tenaska Power Service Company (2)	ERCOT	SPP	OS	N/A	Various	Various		44,035	44,035
28	Brazos Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
29	Hearne, City of (1)	Various	Various	SFP	N/A	Various	Various			
30	Texas-New Mexico Power Company (1)	Various	Various	SFP	N/A	Various	Various			
31	Brenham, City of (1)	Various	Various	SFP	N/A	Various	Various			
32	Hempstead, City of (1)	Various	Various	SFP	N/A	Various	Various			

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)
33	Tex-La Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
34	Bridgeport, City of (1)	Various	Various	SFP	N/A	Various	Various			
35	Guzman Energy (2)	Various	Various	SFP	N/A	Various	Various		21,080	21,080
36	Kerrville Public Utility Board (1)	Various	Various	SFP	N/A	Various	Various			
37	Brownsville Public Utilities Board (1)	Various	Various	SFP	N/A	Various	Various			
38	LaGrange Utilities (1)	Various	Various	SFP	N/A	Various	Various			
39	Waelder, City of (1)	Various	Various	SFP	N/A	Various	Various			
40	Bryan Texas Utilities (1)	Various	Various	SFP	N/A	Various	Various			
41	Lamar County Electric Cooperative (1)	Various	Various	SFP	N/A	Various	Various			
42	Weatherford, City of (1)	Various	Various	SFP	N/A	Various	Various			
43	Burnet, City of (1)	Various	Various	SFP	N/A	Various	Various			
44	Lampasas, City of (1)	Various	Various	SFP	N/A	Various	Various			
45	Weimer, City of (1)	Various	Various	SFP	N/A	Various	Various			
46	Centerpoint Energy Houston Electric, LLC (1)	Various	Various	SFP	N/A	Various	Various			
47	Lexington, City of (1)	Various	Various	SFP	N/A	Various	Various			
48	Westar Energy Inc. (2)	ERCOT	SPP	OS	N/A	Various	Various		82,304	82,304
49	Central Texas Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
50	Llano, City of (1)	Various	Various	SFP	N/A	Various	Various			
51	Western Farmers Electric Cooperative (1)	Various	Various	SFP	N/A	Various	Various			
52	Coleman, City of (1)	Various	Various	SFP	N/A	Various	Various			
53	Lockhart, City of (1)	Various	Various	SFP	N/A	Various	Various			
54	Whitesboro, City of (1)	Various	Various	SFP	N/A	Various	Various			
55	College Station, City of (1)	Various	Various	SFP	N/A	Various	Various			
56	Lubbock, City of (1)	Various	Various	SFP	N/A	Various	Various			
57	Yoakum, City of (1)	Various	Various	SFP	N/A	Various	Various			
58	Castroville, City of (1)	Various	Various	SFP	N/A	Various	Various			
59	Luling, City of (1)	Various	Various	SFP	N/A	Various	Various			
60	Mercuria Energy (1)	Various	Various	SFP	N/A	Various	Various		39,692	39,692
61	Cuero, City of (1)	Various	Various	SFP	N/A	Various	Various			
62	MAG Energy Solutions (2)	Various	Various	SFP	N/A	Various	Various		186,583	186,583
63	MFT Energy (1)	Various	Various	SFP	N/A	Various	Various		50,398	50,398
64	CWP Energy	Various	Various	SFP	N/A	Various	Various		50,681	50,681
65	Mason, City of (1)	Various	Various	SFP	N/A	Various	Various			

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)
66	TransAlta Energy Marketing (1)	Various	Various	SFP	N/A	Various	Various			
67	Conoco Phillips (1)	Various	Various	SFP	N/A	Various	Various		7	7
68	Denton Municipal Electric (1)	Various	Various	SFP	N/A	Various	Various			
69	Moulton, City of (1)	Various	Various	SFP	N/A	Various	Various			
70	Dynasty Power (2)	ERCOT	SPP	OS	N/A	Various	Various		100,240	100,240
71	EDC Power LLC (1)	Various	Various	SFP	N/A	Various	Various		750	750
72	New Braunfels Utilities (1)	Various	Various	SFP	N/A	Various	Various			
73	Canadian Wood Products Energy (1)	Various	Various	SFP	N/A	Various	Various			
74	Endure Energy LLC (2)	ERCOT	SPP	OS	N/A	Various	Various		31,248	31,248
75	Oncor Electric Delivery (1)	Various	Various	SFP	N/A	Various	Various			
76	Farmersville, City of (1)	Various	Various	SFP	N/A	Various	Various			
77	Pedernales Electric Cooperative, Inc (1)	ERCOT	SPP	OS	N/A	Various	Various			
78	TEC Energy Inc (1)	Various	Various	SFP	N/A	Various	Various		6	6
79	Fayette Electric Cooperative (1)	Various	Various	SFP	N/A	Various	Various			
80	Rainbow Energy Marketing (2)	ERCOT	SPP	OS	N/A	Various	Various		444,516	444,516
81	The Energy Authority (1)	Various	Various	SFP	N/A	Various	Various		5,144	5,144
82	Flatonia, City of (1)	Various	Various	SFP	N/A	Various	Various			
83	Rayburn Country Electric Cooperative, Inc (1)	Various	Various	SFP	N/A	Various	Various			
84	Floresville Electric Power System (1)	Various	Various	SFP	N/A	Various	Various			
85	Rio Grande Electric Coop (1)	Various	Various	SFP	N/A	Various	Various			
86	Fredericksburg, City of (1)	Various	Various	SFP	N/A	Various	Various			
87	Robstown Utility System, City of (2)	Various	Various	SFP	N/A	Various	Various			
88	Garland Power and Light (1)	Various	Various	SFP	N/A	Various	Various			
89	San Antonio City Public Service (1)	Various	Various	SFP	N/A	Various	Various			
90	Georgetown, City of (1)	Various	Various	SFP	N/A	Various	Various			
91	Macquarie Energy LLC (1)	Various	Various	SFP	N/A	Various	Various		4,481	4,481
92	GEUS (1)	Various	Various	SFP	N/A	Various	Various			
93	San Marcos, City of (1)	Various	Various	SFP	N/A	Various	Various			
94	San Saba, City of (1)	Various	Various	SFP	N/A	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			59,342	59,342
2			114,701	114,701
3			135,901	135,901
4			24,091,289	24,091,289
5			2,547,248	2,547,248
6			121,526	121,526
7			1,422,713	1,422,713
8			8,245	8,245
9			584,847	584,847
10			24,826	24,826
11			46,915	46,915
12			20,536	20,536
13			156,208	156,208
14			165,023	165,023
15			60,924	60,924
16			119,933	119,933
17			196,994	196,994
18			90,728	90,728
19			5,219,164	5,219,164
20			4,041,802	4,041,802
21			88,769	88,769
22			309,483	309,483
23			80,595	80,595
24			13,270,882	13,270,882
25			125,241	125,241
26			375,388	375,388
27			64,075	64,075
28			33,984,112	33,984,112
29			87,189	87,189
30			18,860,201	18,860,201
31			503,869	503,869
32			109,786	109,786
33			1,359,284	1,359,284
34			122,335	122,335
35			24,170	24,170
36			986,655	986,655
37			2,321,795	2,321,795
38			139,854	139,854
39			41,643	41,643
40			3,625,126	3,625,126
41			469,808	469,808
42			848,189	848,189
43			172,638	172,638
44			218,914	218,914
45			68,428	68,428
46			164,636,534	164,636,534
47			24,170	24,170
48			99,155	99,155

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
49			1,394,066	1,394,066
50			91,945	91,945
51			3,154	3,154
52			73,494	73,494
53			243,375	243,375
54			80,549	80,549
55			1,898,805	1,898,805
56			3,849,432	3,849,432
57			176,031	176,031
58			63,887	63,887
59			114,233	114,233
60			39,811	39,811
61			186,607	186,607
62			192,419	192,419
63			47,662	47,662
64			65,452	65,452
65			52,262	52,262
66			2,207	2,207
67			7	7
68			3,230,611	3,230,611
69			21,939	21,939
70			108,351	108,351
71			752	752
72			2,791,755	2,791,755
73			(9,669)	(9,669)
74			34,392	34,392
75			242,757,427	242,757,427
76			68,796	68,796
77			14,955,804	14,955,804
78			6	6
79			598,765	598,765
80			473,113	473,113
81			5,159	5,159
82			53,397	53,397
83			9,772,256	9,772,256
84			715,800	715,800
85			585,428	585,428
86			293,966	293,966
87			159,215	159,215
88			4,108,004	4,108,004
89			43,788,774	43,788,774
90			1,447,927	1,447,927
91			4,068	4,068
92			1,013,276	1,013,276
93			1,144,404	1,144,404
94			83,700	83,700
35				

Name of Respondent: AEP Texas	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
Transmission Cost of Service pursuant to Texas Substantive Rule 23.67
(2) High Voltage Direct Current Tie

Name of Respondent: AEP Texas	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					

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)
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				
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Name of Respondent: AEP Texas	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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	American Electric Power Service Corporation (AEPSC) (1, 2, 3)	SFP					601,371	601,371
2	Wind Energy Transmission Texas (2, 4)	SFP					8,406,819	8,406,819
3	[(a)] Texas-New Mexico Power Company (2)	SFP					11,662,502	11,662,502
4	East Texas Electric Cooperative (2)	SFP					(60,483)	(60,483)
5	Brownsville Public Utilities Board (2)	SFP					893,673	893,673
6	Lampasas, City of (2)	SFP					1,859,708	1,859,708
7	Rayburn Country Electric Cooperative, Inc (2)	SFP					4,638,119	4,638,119
8	Oncor Electric Delivery (2)	SFP					118,197,393	118,197,393
9	Cherokee County Electric Cooperative (2)	SFP					18,573	18,573
10	Cross Texas Transmission (2, 4)	SFP					6,331,862	6,331,862
11	Deep East Texas Electric Cooperative (2)	SFP					13,436	13,436
12	Denton Municipal Electric (2)	SFP					4,746,002	4,746,002
13	Electric Transmission Tx, LLC (2)	SFP					28,717,037	28,717,037
14	[(b)] Fayette Electric Cooperative (2)	SFP					14,078	14,078
15	Farmers Electric Cooperative (2)	SFP					63,588	63,588
16	Garland Power and Light (2)	SFP					5,837,026	5,837,026
17	Grayson-Collin Electric Cooperative (2)	SFP					145,967	145,967
18	Houston County Electric Cooperative (2)	SFP					145,543	145,543
19	Lone Star Transmission, LLC (2, 4)	SFP					8,726,205	8,726,205
20	Lower Colorado River Authority (2)	SFP					53,458,169	53,458,169
21	Lyntegar Electric Cooperative (2)	SFP					72,990	72,990
22	NRG Power Marketing Inc. (2)	SFP					6,906,900	6,906,900
23	Rio Grande Electric Cooperative (2)	SFP					63,318	63,318
24	Sharyland Utilities, LP (2)	SFP					3,618,585	3,618,585
25	San Miguel Electric Cooperative (2)	SFP					131,665	131,665
26	Southwest Texas Electric Cooperative, Inc (2)	SFP					6,108	6,108

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY MegaWatt Hours Received (c)	TRANSFER OF ENERGY MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
27	Texas Municipal Power Agency (2)	SFP					2,796,742	2,796,742
28	Trinity Valley Electric Cooperative (2)	SFP					68,803	68,803
29	Wood County Electric Cooperative (2)	SFP					12,196	12,196
30	Austin Energy (2)	SFP					8,016,509	8,016,509
31	Bandera Electric Cooperative (2)	SFP					510,352	510,352
32	Brazos Electric Cooperative (2)	SFP					12,137,949	12,137,949
33	Bryan Texas Utilities (2)	SFP					3,310,847	3,310,847
34	Centerpoint Energy Houston Electric, LLC (2)	SFP					47,152,001	47,152,001
35	College Station, City of (2)	SFP					354,876	354,876
36	Floresville Electric Power System (2)	SFP					41,379	41,379
37	GEUS (2)	SFP					290,162	290,162
38	Golden Spread Electric Cooperative (2)	SFP					603,224	603,224
39	Lamar County Electric Cooperative (2)	SFP					26,556	26,556
40	San Antonio City Public Service (2, 4)	SFP					20,253,485	20,253,485
41	San Bernard Electric Cooperative (2)	SFP					366,524	366,524
42	South Texas Electric Cooperative, Inc (2)	SFP					8,294,706	8,294,706
43	Transmission Cost Recovery Factor (5)	SFP					(532,791)	(532,791)
	TOTAL						368,919,673	368,919,673

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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Respondent is an affiliated company of American Electric Power Service Corporation

(2) Transmission Cost of Service pursuant to Texas Substantive Rule 23.67

(3) High Voltage Direct Current (HVDC) East Tie facilities charge

(4) Transmission service surcharge

(5) Transmission Cost Recovery Factor Deferral

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Electric Transmission Texas, LLC (ETT) is a joint venture of which American Electric Power is a 50% member.

Name of Respondent: AEP Texas	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	302,386
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	145,989
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Associated Business Development	246,102
7	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	34,828
8	Chamber Of Commerce	480,999
9	Companies Billed to or from Respondent	159,554
46	TOTAL	1,369,858

Name of Respondent: AEP Texas	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			42,432,461		42,432,461
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	148,780,514				148,780,514
8	Distribution Plant	167,836,738				167,836,738
9	Regional Transmission and Market Operation					
10	General Plant	22,060,879	38,964			22,099,843
11	Common Plant-Electric					
12	TOTAL	338,678,131	38,964	42,432,461		381,149,556

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	TRANSMISSION PLANT						
13	TCC						
14	350 (Rights)	133.746					
15	352	134.971					
16	353	1,756.101					
17	353.16	57.353					
18	354	47.11					
19	355	1,260.086					
20	356	644.307					
21	356.16	129.265					
22	357	34.168					
23	358	27.786					
24	358.16	1.437					
25	359	0.054					
26	TCC SUM	4,226.384					
27	TNC						
28	350 (Rights)	89.772					
29	352	116.672					
30	353-Dist & Trans	860.84					
31	353.16	26.525					
32	354	48.244					
33	355	837.868					
34	356	322.367					
35	356.16	89.568					
36	357	11.06					
37	358	0.002					
38	358.16	0.745					
39	TNC SUM	2,403.663					
40	TRANSMISSION SUM	6,630.047					
41	DISTRIBUTION						
42	TCC						
43	360 (Rights)	2.454					
44	361	72.397					
45	362	681.246					
46	362.16	17.531					
47	364	930.978					
48	365	865.844					
49	366	93.844					
50	367	417.572					
51	368	731.984					
52	369	299.558					
53	370	36.781					
54	370 AMI	133.858					
55	371	58.284					
56	373	113.349					
57	TCC SUM	4,455.68					
58	360 (Rights)	4.775					

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)
59	361	16.57					
60	362	237.901					
61	362.16	4.541					
62	364	291.578					
63	365	234.979					
64	366	32.722					
65	367	87.136					
66	368	199.108					
67	369	114.919					
68	370	12.078					
69	370 AMI	29.897					
70	371	15.971					
71	372	0.087					
72	373	28.497					
73	TNC SUM	1,310.759					
74	DISTRIBUTION SUM	5,766.439					
75	GENERAL PLANT						
76	390	383.965					
77	391	9.177					
78	392						
79	393	2.197					
80	394	47.632					
81	395	0.462					
82	396	0.022					
83	397	156.458					
84	397.16	3.775					
85	398	7.357					
86	TCC SUM	611.045					
87	389 (Rights)						
88	390-Dist & Trans	65.127					
89	391-Dist & Trans	3.199					
90	391.11	0.003					
91	393-Dist & Trans	0.662					
92	394-Dist & Trans	21.846					
93	397-Dist & Trans	103.963					
94	397.12	0.011					
95	397.16	4.777					
96	398	3.255					
97	TNC SUM	202.843					
98	GENERAL PLANT SUM	813.888					
99	DEPRECIABLE SUM	13,210.374					

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

REGULATORY COMMISSION EXPENSES

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

						EXPENSES INCURRED DURING YEAR			
						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)
1	Expenses incurred related to Distribution Cost Recovery Factor Filings - PUCT Docket No.s. 45787, 45788, 47015 and 48222		15,018	15,018		Electric	928	15,018	
2	Expenses incurred in Interim Transmission Cost Cases and other Regulatory/Legislative actions relating to Transmission - PUCT Docket No Period 2020s 48507 and 481931		31,369	31,369		Electric	928	31,369	
3	Expenses incurred related to managing Formula Rates for AEP's West Operating Companies and Transco's		177,064	177,064		Electric	928	177,064	
4	Expenses incurred relating to Determination of System Restoration Costs - Hurricane Harvey - PUCT Docket No. 48577		3,815	3,815		Electric	928	3,815	
5	Expenses incurred in Energy Efficiency Cost Recovery Factor filings		42,484	42,484		Electric	928	42,484	
6	Minor Items (less than $25,000)		89,105	89,105		Electric	928	89,105	512,668
7	Texas AMI Final Filing					Electric	928		
8	2024 AEP Texas Base Case		889,211	889,211		Electric	928	889,211	
9	2021 Storm URI Investigation		59,586	59,586		Electric	928	59,586	
10	TX 2023 DCRF Filing		215,934	215,934		Electric	928	215,934	
11	Texas Opcos - All Bus Units		6,376	6,376		Electric	928	6,376	
46	TOTAL		1,529,962	1,529,962				1,529,962	512,668

	AMORTIZED DURING YEAR		
Line No.	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1			
2			
3			
4			
5			
6			512,668
7			
8			
9			
10			
11			
46			512,668

Name of Respondent: AEP Texas	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. (1)(e) Transmission and Distribution	Rolls-Royce 1MW SOFC Test & Eval					
2	A. (2) Transmission	Transmission RD&D Program Mgmt	12,989		566	12,989	
3		1 Items < $50,000	224		566	224	
4	A. (3) Distribution	Distribution Program Management	16,233		588	16,233	
5	A. (6) Other	Corporate Technology Prog Mgmt	177		566	177	
6		2 Items < $50,000	169		588	169	
7	A. (6)(f) Metering	Advanced Metering Equipment	2,576		588	2,576	
8	A. (6)(g) Research General	DTC Walnut Test Facility	1,798		566	1,798	
9			1,464		588	1,464	
10		1 Items < $50,000					
11	A. (7) Total Cost Incurred Intermally						
12	B. Electric R&D External	1 Items < $50,000		37,514	566	37,514	
13				55,110	588	55,110	
14	B. (1) Electric Power Research Institute	1 Items < $50,000		585,300	566	585,300	
15				232,176	588	232,176	
16		Information Technology EPRI Annual Research Portfolio		12,423	566	12,423	
17				59,335	588	59,335	

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
18		Low Carbon Resource Initiative		56,782	566	56,782	
19				47,048	588	47,048	
20				1,488	566	1,488	
21		2 Items < $50,000		107	588	107	
22	B. (4) Research Support to Others	2 Items < $50,000		15	566	15	
23	B. (5) Total Cost Incurred Externally						
24		Total	35,631	1,087,298		1,122,929	
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Name of Respondent: AEP Texas	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			
4	Transmission	4,090,706		
5	Regional Market			
6	Distribution	22,666,234		
7	Customer Accounts	4,823,173		
8	Customer Service and Informational	1,907,598		
9	Sales			
10	Administrative and General	996,477		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	34,484,188		
12	Maintenance			
13	Production	594		
14	Transmission	4,946,649		
15	Regional Market			
16	Distribution	23,687,796		
17	Administrative and General	4,222,849		
18	TOTAL Maintenance (Total of lines 13 thru 17)	32,857,888		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	594		
21	Transmission (Enter Total of lines 4 and 14)	9,037,355		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	46,354,030		
24	Customer Accounts (Transcribe from line 7)	4,823,173		
25	Customer Service and Informational (Transcribe from line 8)	1,907,598		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	5,219,326		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	67,342,076	4,431,204	71,773,280
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			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	67,342,076	4,431,204	71,773,280
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	88,857,887	5,846,976	94,704,863
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	88,857,887	5,846,976	94,704,863
72	Plant Removal (By Utility Departments)			
73	Electric Plant	14,775,661	972,260	15,747,921
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	14,775,661	972,260	15,747,921
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	163 - Stores Expense Undistributed	7,604,481	(7,604,481)	
80	165 - Other Prepayments			
81	182 - Other Regulatory Assets			
82	183 - Prelim Survey	773	(773)	
83	184 - Clearing Accounts	3,645,186	(3,645,186)	
84	185 - ODD Temporary Facilities	429,958		429,958
85	186 - Misc Deferred Debits	59,582		59,582
86	188 - Research & Development			
87	228 - RAD Waste Accrual			
88	402 - Maintenance Exp			
89	407 - Regulatory Debits			
90	417 - Misc Exp			
91	418 - Nonoperating Rental Income			
92	421 - Misc Nonoperating Income			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
93	426 - Political Activities	180,852		180,852
94	451 - Misc Service Rev - Nonaffil			
95	456 - Other Electric Revenue			
95	TOTAL Other Accounts	11,920,832	(11,250,440)	670,392
96	TOTAL SALARIES AND WAGES	182,896,456		182,896,456
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Name of Respondent: AEP Texas	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: AEP Texas	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)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
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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)
41					
42					
43					
44					
45					
46	TOTAL				
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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: AEP Texas	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	0								
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

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FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto
AEP Texas' transmission service is administered through a Regional Transmission Organization (RTO) and requested information is not available on an individual company basis.

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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

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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)	
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	0	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	0
10	Purchases (other than for Energy Storage)	0			
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)	0			

Name of Respondent: AEP Texas	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					
30	February					
31	March					
32	April					
33	May					
34	June					
35	July					
36	August					
37	September					
38	October					
39	November					
40	December					
41	Total	0	0			

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

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: 0
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	
6	Net Peak Demand on Plant - MW (60 minutes)	
7	Plant Hours Connected to Load	
8	Net Continuous Plant Capability (Megawatts)	
9	When Not Limited by Condenser Water	
10	When Limited by Condenser Water	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	Cost of Plant: Land and Land Rights	
14	Structures and Improvements	
15	Equipment Costs	
16	Asset Retirement Costs	
17	Total cost (total 13 thru 20)	
18	Cost per KW of Installed Capacity (line 17/5) Including	
19	Production Expenses: Oper, Supv, & Engr	
20	Fuel	
21	Coolants and Water (Nuclear Plants Only)	
22	Steam Expenses	
23	Steam From Other Sources	
24	Steam Transferred (Cr)	
25	Electric Expenses	
26	Misc Steam (or Nuclear) Power Expenses	
27	Rents	
28	Allowances	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Boiler (or reactor) Plant	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Steam (or Nuclear) Plant	
34	Total Production Expenses	

Line No.	Item (a)	Plant Name: 0
35	Expenses per Net kWh	

35	**Plant Name**	0	0	0
36	Fuel Kind	COAL	COMPOSIT	OIL
37	Fuel Unit			
38	Quantity (Units) of Fuel Burned			
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)			
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year			
41	Average Cost of Fuel per Unit Burned			
42	Average Cost of Fuel Burned per Million BTU			
43	Average Cost of Fuel Burned per kWh Net Gen			
44	Average BTU per kWh Net Generation			

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

Hydroelectric Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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	

Page 406-407

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

Pumped Storage Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	
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	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
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	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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
	Page 408-409	

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

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1													
2													
3													
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35													

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)
36													
37													
38													
39													
40													
41													
42													
43													
44													
45													
46													
Page 410-411													

Name of Respondent: AEP Texas	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)
1												
2												
3												
4												
5												
6												
7												
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31												
32												
33												
34												
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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34							
35	0	0	0		0	0	0

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

ENERGY STORAGE OPERATIONS (Small Plants)

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

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
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3									
4									
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8									
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27									
28									
29									
30									
31									
32									
33									
34									
35									
36	TOTAL			0	0	0	0	0	0

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

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		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	AEP TEXAS CENTRAL	AEP TEXAS CENTRAL							
2	TL501 Hyperion	Helios (Argo)	345.00	345.00	2	0.02	0	1	2-795 ACSR
3	TL502 Hyperion	Cottonwood (WETT)	345.00	345.00	2	0.07	0	1	2-795 ACSR
4	TL520 SALVARE	IRIS	345.00	345.00	1	0.03	0	1	795 ACSR
5	TL1083 NORTH EDINBURG	RIO HONDO	345.00	345.00	1	15.38	0	1	2x795.0 ACSR
6	TL1083 NORTH EDINBURG	RIO HONDO			2	22.92	0		
7	TL1083 NORTH EDINBURG	RIO HONDO			1	0.94	0		2x1590 ACSR
8	TL1098 LA PALMA	RIO HONDO	345.00	345.00	1	0.17	0	1	795.0 ACSR
9	TL1098 LA PALMA	RIO HONDO			2	0.13	0	1	795.0 ACSR
10	TL3113A BLESSING	STP	345.00	345.00	2	13.23	0	1	2x795.0 ACSR
11	TL3131 STP	WA PARRISH	345.00	345.00	2	14.22	0	1	2x795.0 ACSR
12	TL5109 LON C HILL	CPSB TIE (SAN ANTONIO)	345.00	345.00	1	2.09	0	1	2x795.0 ACSR
13	TL5109 LON C HILL	CPSB TIE (SAN ANTONIO)	345.00	345.00	2	55.39	0	1	2x795.0 ACSR
14	TL5109 LON C HILL	CPSB TIE (SAN ANTONIO)	345.00	345.00	1	0.71	0	1	2X954 ACSR
15	TL5114 LON HILL	WHITEPOINT CKT #1	345.00	345.00	1	9.78	0	2	2x795.0 ACSR
16	TL5114 LON HILL	WHITEPOINT CKT #1	345.00	345.00	2	11.00	0	1	2x795.0 ACSR
17	TL5115 WHITEPOINT	STP	345.00	345.00	1	9.75	0	1	2x795.0 ACSR
18	TL5115 WHITEPOINT	STP	345.00	345.00	2	87.11	0	1	2x795.0 ACSR
19	TL5115 WHITEPOINT	STP	345.00	345.00	2	27.00	0	1	2x1025.4 ACCC
20	TL5115 WHITEPOINT	STP	345.00	345.00	1	1.24	0	1	2x954 ACSR
21	TL5138 AJO	RIO HONDO	345.00	345.00	1	1.00	0	1	2x1590.0 ACSR
22	TL5138 AJO	RIO HONDO	345.00	345.00	1	0.36	0	1	2x954 ACSS
23	TL5138 AJO	RIO HONDO	345.00	345.00	2	65.52	0	1	2x1026 ACCC
24	TL3143 Lon C Hill	Coleto Creek 345KV Line	345.00	345.00	1	20.50	0	1	2x795.0 ACSR
25	TL3143 Lon C Hill	Coleto Creek 345KV Line	345.00	345.00	2	59.02	0	1	2x795.0 ACSR
26	TL3143 Lon C Hill	Coleto Creek 345KV Line	345.00	345.00	1	0.47	0	1	1590 ACSR
27	TL5138A LON HILL	NELSON SHARPE	345.00	345.00	2	20.81	0	1	2x795.0 ACSR
28	TL5138B AJO	NELSON SHARPE	345.00	345.00	1	0.84	0	1	2x1590.0 ACSR
29	TL5138B AJO	NELSON SHARPE	345.00	345.00	2	36.20	0		2x795.0 ACSR
30	TL5138E LA PALMA	RIO HONDO CKT #2	345.00	345.00	2	9.75	0	1	2x795.0 ACSR
31	TL5145 LON HILL	NORTH EDINBURG	345.00	345.00	1	0.27	0	1	2x1026 ACCC
32	TL5145 LON HILL	NORTH EDINBURG	345.00	345.00	2	111.65	0	1	2x1026 ACCC
33	TL5271 CEBOLLA	LADEKIDDE 345KV TIE LINE	345.00	345.00	1	0.04	0	1	2x954 ACSS
34	TL5282 RIO HONDO	MAJADAS 345KV LINE	345.00	345.00	1	9.42	0	1	2x957 ACSR
35	TL5293 BONILLA	EL RAYO 345KV TIE LINE	345.00	345.00	1	0.04	0	1	2x954 ACSR
36	TL5294 Grissom	Cranell	345.00	345.00	1	0.02	0	1	2-954 ACSR
37	TL5325 BONILLA	EL TRUENO 345KV TIE LINE	345.00	345.00	1	0.04	0	1	2x954 ACSR
38	TL5327 Angstrom	SDI	345.00	345.00	1	0.95	0	1	2x954 ACSR
39	TL5337 Grissom	Blackjack Creek	345.00	345.00	1	0.02	0	1	2x954 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)
40	TL5360 Katoen	El Algodon	345.00	345.00	1	0.10	0	1	2x795 ACSR
41	TL5361 Tango	Foxtrot	345.00	345.00	1	0.06	0	1	2x795 ACSR
42	TL5365 Tango	Sparta	345.00	345.00	1	0.09	0	1	2x795.0 ACSR
43	TL5378 Cebolla	El Sauz	345.00	345.00	1	0.05	0	1	2-954 ACSS
44	TL3131 STP	HL&P CORRIDOR	345.00	345.00	2		19	5	2x795 ACSR
45	TL1001 BATES	GARZA	138.00	138.00	1	30.42	3	1	795.0 ACSR
46	TL1002A GARZA	ROMA TAP	138.00	138.00	1	16.39	2	1	795.0 ACSR
47	TL1002B FALCON SWITCHING	ROMA TAP	138.00	138.00	1	4.87	0	1	795.0 ACSR
48	TL1002C FALCON SWITCHING	FALCON DAM (US) CKT#1	138.00	138.00	2	4.50	0	1	4/0 ACSR
49	TL1004 BATES	NORTH EDINBURG CKT#1	138.00	138.00	1	22.17	0	1	1272.0 ACSR
50	TL1005 FALFURIAS	NORTH EDINBURG	138.00	138.00	1	37.80	0	1	795.0 ACSR
51	TL1006 JL BATES	SHARYLAND	138.00	138.00	1	0.31	0	1	1272.0 ACSS
52	TL1008 LA PALMA	WESMER	138.00	138.00	1	16.15	0	1	795.0 ACSR
53	TL1019 FRONTERA	NORTH MCALLEN	138.00	138.00	1	12.80	0	1	1272.0 ACSR
54	TL1019 FRONTERA	NORTH MCALLEN	138.00	345.00	1	0.33	0	2	1272.0 ACSR
55	TL1009A HARLINGEN SS	RIO HONDO	138.00	138.00	1	1.76	0	1	795.0 ACSR/AW
56	TL1009A HARLINGEN SS	RIO HONDO	138.00	138.00	2	12.16	0	1	795.0 ACSR/AW
57	TL1009B RAYMONDVILLE #2	RIO HONDO	138.00	138.00	2	23.89	0	1	795.0 ACSR
58	TL1010 Armstrong	Raymondville #2 138KV Line	138.00	138.00	2	32.00	0	1	795 ACSR
59	TL1011 FRONTERA	RIO GRANDE CITY	138.00	138.00	1	3.54	0	1	795.0 ACSR
60	TL1029 Rio Rico	Hidalgo	69.00	138.00	1		2	1	795.0 ACSS
61	TL1029 Rio Rico	Hidalgo	69.00	138.00	2	20.44	0	1	4/0 ACSR
62	TL5295 LA PALMA	CAVAZOS	69.00	138.00	1	0.36	0	1	795 ACSS/AW
63	TL1054 HARLINGEN SS	ACSR	138.00	138.00	2	1.71	0	1	795.0 ACSR
64	TL1059 SOUTHEAST EDINBURG	MVEC PHARR	138.00	138.00	1	1.63	0	1	795.0 ACSS
65	TL1060 POLK	SOUTH MCALLEN	138.00	138.00	1	2.71	0	1	795.0 ACSS
66	TL1061 HEC	NORTH EDINBURG CKT #1	138.00	138.00	1	1.06	0	1	2x795.0 ACSR
67	TL1062 HEC	WESLACO SS	138.00	138.00	1	4.40	0	1	795.0 ACSR
68	TL1070 PORT ISABEL	CAUSEWAY	138.00	138.00	1	6.70	0	1	795 ACSS
69	TL1071 Causeway	South Padre Island	138.00	138.00	1	6.89	0	1	795 ACSS
70	TL1072 NORTH EDINBURG	DUKE #2	138.00	138.00	1	7.42	0	1	795.0 ACSS
71	TL1072A HEC EXTENSION	DUKE #2	138.00	138.00	1	0.80	0	2	795.0 ACSS
72	TL1073 Las Milpas (MVEC)	Weslaco Unit 138KV Line	138.00	138.00	1	0.15	0	1	795 ACSS
73	TL1073 Las Milpas (MVEC)	Weslaco Unit 138KV Line	138.00	138.00	2	14.66	0	1	477.0 ACSR
74	TL1073C SOUTH MCALLEN	STEWART ROAD	138.00	138.00	2	10.06	0	1	795.0 ACSR
75	TL1074B LA PALMA	LAURELES	138.00	138.00	1	9.40	0	1	795.0 ACSR
76	TL1074C LAURELES	PORT ISABEL	138.00	138.00	1	7.62	0	1	795.0 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)
77	TL1074C LAURELES	PORT ISABEL	138.00	138.00	2	6.87	0	1	795.0 ACSR
78	TL1075 LA PALMA	PUB LOMA ALTA	138.00	138.00	1	12.22	0	1	795.0 AAAC
79	TL1075 LA PALMA	PUB LOMA ALTA	138.00	138.00	2	10.00	0	1	795.0 ACSR
80	TL1075 LA PALMA	PUB LOMA ALTA	138.00	138.00	1	0.24	0	1	2-795 ACSS
81	TL1076 PUB (Loma Alta)	Carbide	138.00	138.00	1	1.00	0	1	795 ACSR
82	TL1076 PUB (Loma Alta)	Carbide	138.00	138.00	1	0.24	0	1	2-795 ACSS
83	TL1077 PORT ISABEL	UNION CARBIDE BROWNSVILLE	138.00	138.00	2	5.85	0	1	477.0 ACSR
84	TL1077 PORT ISABEL	UNION CARBIDE BROWNSVILLE	138.00	138.00	2	6.88	0	1	795.0 ACSR
85	TL1079 Wesmer	Weslaco Unit 138KV Line	138.00	138.00	1	5.32	0	1	477.0 AAC
86	TL1079 Wesmer	Weslaco Unit 138KV Line	138.00	138.00	1	0.11	0	1	795 ACSS
87	TL1080 LA PALMA	MILITARY HIGHWAY	138.00	138.00	1	2.03	0	1	795.0 ACSR
88	TL1080 LA PALMA	MILITARY HIGHWAY	138.00	138.00	2	19.01	0	1	795.0 ACSR
89	TL1081 NORTH MCALLEN	SOUTH MCALLEN	138.00	138.00	1	4.71	0	1	795.0 ACSS
90	TL1082 PHARR (MVEC)	PHARR	138.00	138.00	1	3.61	0	1	795.0 ACSS
91	TL1084 POLK	SOUTH MCALLEN	138.00	138.00	1	3.66	0	1	795.0 ACSR
92	TL1085 PALMHURST TAP	SOUTH MCALLEN	138.00	138.00	1	1.70	0	1	1270.0 ACSR
93	TL1086A NORTH EDINBURG	MVG (CALPINE) GT1	138.00	138.00	1	0.18	0	1	1590.0 ACSR
94	TL1086B NORTH EDINBURG	MVG (CALPINE) GT2	138.00	138.00	1	0.18	0	1	1590.0 ACSR
95	TL1086C NORTH EDINBURG	MVG (CALPINE) ST1	138.00	138.00	1	0.17	0	1	1590.0 ACSR
96	TL1091 MILITARY HIGHWAY	UNION CARBIDE	138.00	138.00	1	4.75	0	1	795.0 ACSR
97	TL1092 NORTH EDINBURG	NORTH MCALLEN	138.00	138.00	1	9.60	0	2	795.0 ACSS
98	TL1093 NORTH MCALLEN	SOUTH MCALLEN	138.00	138.00	1	2.63	0	1	795.0 ACSS
99	TL1093 NORTH MCALLEN	SOUTH MCALLEN	138.00	138.00	2	0.65	0	1	795.0 ACSS
100	TL1094 SOUTH MCCALLEN	LAS MILPAS (MVEC)	138.00	138.00	1	0.35	0	1	959 ACSS
101	TL1095 MILITARY HIGHWAY	CFE TIE	138.00	138.00	1	0.14	0	1	795.0 ACSR
102	TL1096 PORT ISABEL	PORT ISABEL	138.00	138.00	4	8.56	0	1	750.0 MCM CU
103	TL1097 LA PALMA	RIO HONDO	138.00	138.00	1	10.26	0	1	2x795.0 ACSS
104	TL1099 RIO HONDO	HARLINGEN SWITCHING STATION	138.00	138.00	1	0.18	0	1	795 ACSR
105	TL1117 FRONTERA	SOUTH MCALLEN	138.00	138.00	1	14.66	0	1	1272.0 ACSR
106	TL1117A AGAVE	SLU TAYLOR	138.00	138.00	1	0.15	0	1	1272.0 ACSR
107	TL1119 RIO GRANDE CITY	ROMA TAP	138.00	138.00	1	7.61	0	1	795.0 ACSR
108	TL1121 PHARR	POLK AVENUE	138.00	138.00	1	3.92	0	1	795.0 ACSS
109	TL1122 HEC	WESLACO SS	138.00	138.00	1	11.52	0	1	795.0 ACSR
110	TL3001 VICTORIA	MEDIO CREEK	138.00	138.00	2	14.42	0	1	336.4 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)
111	TL3001 VICTORIA	MEDIO CREEK	138.00	138.00	2	32.48	0	1	795.0 ACSR
112	TL3001 VICTORIA	MEDIO CREEK	138.00	138.00	2	0.35	0	1	4/0 ACSR
113	TL3146 MEDIO CREEK	LON C HILL	138.00	138.00	1	0.30	0	1	959.6 ACSS
114	TL3146 MEDIO CREEK	LON C HILL	138.00	138.00	2	1.30	0	1	336.4 ACSR
115	TL3146 MEDIO CREEK	LON C HILL	138.00	138.00	1	23.40	0	1	795 ACSS
116	TL3146 MEDIO CREEK	LON C HILL	138.00	138.00	1	1.20	0	1	795 ACSR
117	TL3002 COLETO	KENEDY SS	138.00	138.00	2	45.14	0	1	795.0 ACSR
118	TL3003 KENEDY SS	CPSB V.H. BRAUNIG	138.00	138.00	2	13.71	0	1	477.0 ACSR
119	TL3004 KENEDY SS	PLEASANTON	138.00	138.00	2	40.14	0	1	266.8 ACSR
120	TL3005 VICTORIA	EDNA	138.00	138.00	2	21.57	0	1	795.0 ACSR
121	TL3006 EDNA	GANADO	138.00	138.00	2	9.72	0	1	795.0 ACSR
122	TL3007 GANADO	EL CAMPO	138.00	138.00	1	2.09	0	1	795.0 AAAC
123	TL3007 GANADO	EL CAMPO	138.00	138.00	1	0.20	0	1	795.0 ACSS
124	TL3007 GANADO	EL CAMPO	138.00	138.00	2	17.73	0	1	795.0 ACSR
125	TL3008 EL CAMPO	LANE CITY PUMP	138.00	138.00	1	1.91	0	1	795.0 ACSR
126	TL3008 EL CAMPO	LANE CITY PUMP	138.00	138.00	2	15.49	0		795.0 ACC
127	TL3009 EL CAMPO	LANE CITY	138.00	138.00	2	1.41	0	1	795.0 ACSR
128	TL3010 LOLITA	VICTORIA	138.00	138.00	2	23.96	0	1	795.0 ACSR
129	TL3010 LOLITA	VICTORIA	138.00	138.00	3	4.36	0	2	795.0 ACSR
130	TL3011 BLESSING	LOLITA	138.00	138.00	2	22.51	0	1	795.0 ACSR
131	TL3012 BLESSING	LANE CITY	138.00	138.00	2	25.50	0	1	477.0 ACSR
132	TL3013 DUPONT SS	VICTORIA NORTH	138.00	138.00	3	7.77	0	2	795.0 ACSR
133	TL3014 BIG THREE	DUPONT SS	138.00	138.00	2	3.39	0	1	477.0 ACSR
134	TL3014 BIG THREE	DUPONT SS	138.00	138.00	2	0.62	0		795.0 ACSR
135	TL3015 FORMOSA	LOLITA	138.00	138.00	2	11.84	0	1	795.0 ACSR
136	TL3016 JOSLIN	ALCOA (1)	138.00	138.00	1	1.00	0	1	1590.0 ACSR
137	TL3017 JOSLIN	ALCOA (2)	138.00	138.00	3	0.09	1	1	1590.0 ACSR
138	TL3018 E S JOSLIN	UNION CARBIDE	138.00	138.00	3	0.43	0	2	795 ACSR & 4/0
139	TL3018 E S JOSLIN	UNION CARBIDE	138.00	138.00	3	14.64	0	1	795 ACSR
140	TL3018 E S JOSLIN	UNION CARBIDE	138.00	138.00	1	3.48	0	2	795 ACSR & 4/0
141	TL3018 E S JOSLIN	UNION CARBIDE	138.00	138.00	1	1.95	0	1	795 ACSR
142	TL3019 AIRCO	RINCON	138.00	138.00	2	51.30	0	1	477.0 ACSR
143	TL3021 DUPONT SS	DUPONT # 1	138.00	138.00	1	2.09	0	1	795.0 AAC
144	TL3022 CELANESE	CONOCO	138.00	138.00	1	0.06	0	1	795.0 ACSR
145	TL3026 DUPONT SS	DUPONT # 2	138.00	138.00	1	2.08	0	1	795.0 AAC
146	TL3027 DUPONT SS	VICTORIA SOUTH	138.00	138.00	3	7.65	0	1	795.0 ACSR
147	TL3034 STP TAP	CELANESE	138.00	138.00	2	2.61	0	1	795 ACSR
148	TL3034 STP TAP	CELANESE	138.00	138.00	1	3.05	0	1	795 ACSS
149	TL3035 BAY CITY	CONOCO	138.00	138.00	1	1.20	0	1	795 ACSR
150	TL3035 BAY CITY	CONOCO	138.00	138.00	2	18.66	0	1	795 ACSR
151	TL3036 BAY CITY	LANE CITY	138.00	138.00	1	15.44	0	1	795.0 ACSS
152	TL3044 SIGMOR	THREE RIVERS	138.00	138.00	2	0.42	0	1	959.6 ACSS
153	TL3044 SIGMOR	THREE RIVERS	138.00	138.00	2	3.17	0	1	795 ACSR/AW
154	TL3045 SIGMOR	STEC ORANGE GROVE	138.00	138.00	2	1.83	0	1	795.0 ACSR
155	TL3046 SIGMOR	STEC SAN MIGUEL	138.00	138.00	1	2.41	0	1	1/0 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)
156	TL3046 SIGMOR	STEC SAN MIGUEL	138.00	138.00	2	1.83	0	1	795.0 ACSR
157	TL3077 GOLIAD	BERCLAIR	69.00	138.00	1	0.02	0	1	477ACSR/AW
158	TL3084 VICTORIA	LCRA CUERO	138.00	138.00	1	0.34	0	1	795.0 ACSR
159	TL3084 VICTORIA	LCRA CUERO	138.00	138.00	2	13.82	0	1	795.0 ACSR
160	TL3085 VICTORIA	LCRA CUERO	138.00	138.00	2	10.88	0	1	795.0 ACSR
161	TL3111 DUPONT SS	JOSLIN	138.00	138.00	2	17.36	0	1	795.0 ACSR
162	TL3111 DUPONT SS	JOSLIN	138.00	138.00	3	0.90	0	1	795.0 ACSR
163	TL3111 DUPONT SS	JOSLIN	138.00	138.00	3	0.05	0	1	795.0 ACSS
164	TL3112 DUPONT SS	JOSLIN	138.00	138.00	1	0.42	0	1	795.0 ACSR
165	TL3112 DUPONT SS	JOSLIN	138.00	138.00	2	13.68	0	1	795.0 ACSR
166	TL3112 DUPONT SS	JOSLIN	138.00	138.00	3	0.18	0	2	795.0 ACSR
167	TL3113 BLESSING	STP TAP	138.00	138.00	1	5.83	0	1	795.0 ACSS
168	TL3114 STP PUMP TAP	STP CONSTRUCTION	138.00	138.00	3	6.30	0	1	795.0 ACSR
169	TL3114 STP PUMP TAP	STP CONSTRUCTION	138.00	138.00	1	0.10	0	1	795.0 ACSR
170	TL3115 STP CONSTRUCTION	STP RIVER PUMP	138.00	138.00	1	4.36	0	1	4/0 ACSR
171	TL3118 COLETO CREEK NORTH	VICTORIA	138.00	138.00	2	11.10	0	1	1590.0 ACSR
172	TL3118 COLETO CREEK NORTH	VICTORIA	138.00	138.00	3	4.81	0	1	1590.0 ACSR
173	TL3119 COLETO CREEK (S)	VICTORIA	138.00	138.00	2	6.29	0	1	1590.0 ACSR
174	TL3119 COLETO CREEK (S)	VICTORIA	138.00	138.00	3	8.53	0	1	1590 ACSR
175	TL3119 COLETO CREEK (S)	VICTORIA	138.00	138.00	1	0.82	0	1	1590 ACSR
176	TL3122 CARBIDE SEADRIFT	VISTRON	138.00	138.00	2	6.13	0	1	477.0 ACSR
177	TL3122 CARBIDE SEADRIFT	VISTRON	138.00	138.00	2	0.42	0	1	795.0 ACSR
178	TL3124 FORMOSA	JOSLIN	138.00	138.00	2	0.69	0	1	795.0 ACSR
179	TL3124 FORMOSA	JOSLIN	138.00	138.00	3	1.79	0	1	795.0 ACSR
180	TL3124 FORMOSA	JOSLIN	138.00	138.00	3	0.05	0	1	795.0 ACSS
181	TL3125 BIG THREE	VISTRON	138.00	138.00	2	10.52	0	1	477.0 ACSR
182	TL3125 BIG THREE	VISTRON	138.00	138.00	2	0.61	0	1	795.0 ACSR
183	TL3126 CELANESE	CONOCO	138.00	138.00	2	10.37	0	1	795.0 ACSR
184	TL3127 AIRCO	CARBIDE	138.00	138.00	2	1.43	0	1	477.0 ACSR
185	TL3139 CHASEFIELD TAP#2	CHASEFIELD	69.00	138.00	1	4.58	0	1	795.0 ACSR
186	TL3150 TULETA	COLETO CREEK	138.00	138.00	1	48.95	0	1	959.6 ACSS/TW
187	TL3151 VICTORIA	(STEC) FANNIN	69.00	138.00	3	15.32	0	1	1025 ACCC
188	TL5001 KINGSVILLE	LON HILL	138.00	138.00	1	37.29	0	1	795.0 ACSR
189	TL5001 KINGSVILLE	LON HILL	138.00	138.00	1	0.50	0	1	477 ACSR
190	TL5001 KINGSVILLE	LON HILL	138.00	138.00	2	29.07	0	1	795.0 ACSR/AW
191	TL5001 KINGSVILLE	LON HILL	138.00	138.00	3	6.87	0	1	795.0 ACSR/AW
192	TL5002 KINGSVILLE	KLEBERG	138.00	138.00	1	1.37	0	1	795.0 ACSR/AW
193	TL5002 KINGSVILLE	KLEBERG	138.00	138.00	2	4.13	0	1	795.0 ACSR/AW
194	TL5003 Kleberg	Armstrong 138KV Line	138.00	138.00	1	5.54	0	1	795 ACSS

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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)
195	TL5003 Kleberg	Armstrong 138KV Line	138.00	138.00	2	9.83	0	1	795 ACSR
196	TL5003A KLEBERG	LOYOLA	138.00	138.00	2	13.50	0	1	795.0 ACSR
197	TL5003B LOYOLA	RAYMONDVILLE #2	138.00	138.00	2	26.06	0	1	795.0 ACSR
198	TL5004 LON HILL	STRATTON	138.00	138.00	2	27.80	0	1	795.0 ACSR
199	TL5005A DAVIS	NELSON SHARPE	138.00	138.00	2	10.10	0	1	795.0 ACSR
200	TL5005B CELANESE	NELSON SHARPE	138.00	138.00	2	10.18	0	1	795.0 ACSR
201	TL5006A FALFURIAS	KING RANCH GAS PLANT	138.00	138.00	2	20.48	0	1	795.0 ACSR
202	TL5006B KING RANCH GAS	STRATTON	138.00	138.00	2	15.76	0	1	795.0 ACSR
203	TL5007 HIGHWAY9	JAVELINA	138.00	138.00	1		2	1	1272.0 ACSR
204	TL5008 JAVELINA	WEST OSO	138.00	138.00	1	0.11	0	1	1272.0 ACSR
205	TL5008 JAVELINA	WEST OSO	138.00	138.00	3	0.04	0	1	1272.0 ACSR
206	TL5009 LON C HILL	WHITEPOINT	138.00	138.00	3	0.72	0	2	2x795.0 ACSR
207	TL5009 LON C HILL	WHITEPOINT	138.00	138.00	3	0.33	0	1	2x795.0 ACSR
208	TL5009 LON C HILL	WHITEPOINT	138.00	138.00	1	15.21	0	1	2x795.0 ACSR
209	TL5009 LON C HILL	WHITEPOINT	138.00	138.00	1	2.90	0	2	2x795.0 ACSR
210	TL5009 LON C HILL	WHITEPOINT	138.00	138.00	2	0.26	0	1	2x795.0 ACSR
211	TL5009 LON C HILL	WHITEPOINT	138.00	138.00	1	0.22	0	1	795 ACSS
212	TL5010 GILA	UP RIVER ROAD	138.00	138.00	1	0.08	0	1	2-795 ACSR
213	TL5011 LON C HILL	CLARKWOOD	138.00	138.00	2	5.92	0	1	795.0 ACSR
214	TL5011 LON C HILL	CLARKWOOD	138.00	138.00	1	0.20	0	1	795 ACSS
215	TL5013 WESTSIDE	HOLLY	138.00	138.00	1	2.68	0	1	1590.0 ACSR
216	TL5013 WESTSIDE	HOLLY	138.00	138.00	1	1.28	0	2	1590.0 ACSR
217	TL5016 B M DAVIS	RODD FIELD	138.00	138.00	1	0.06	3	1	T2 795
218	TL5016 B M DAVIS	RODD FIELD	138.00	138.00	1	0.06	0	1	1590.0 ACSR
219	TL5097 HIGHWAY 9	NUECES BAY CKT #2	138.00	138.00	1		2	1	1272.0 ACSR
220	TL5017 NUECES BAY	CABLE TERMINAL #1	138.00	138.00	4	0.41	0	1	3500kcmil XLPE
221	TL5020 S.W. REFINING	MORRIS STREET	138.00	138.00	1	1.90	0	1	795.0 AAC
222	TL5020 S.W. REFINING	MORRIS STREET	138.00	138.00	1	0.71	0	1	795.0 ACSS/AW
223	TL5022 NUECES BAY	CABLE TERMINAL #2	138.00	138.00	4	0.41	0	1	3500kcmil XLPE
224	TL5127 CABLE #2	MORRIS STREET	138.00	138.00	1	3.80	0	1	1272.0 ACSR
225	TL5127 CABLE #2	MORRIS STREET	138.00	138.00	1	1.20	0	1	795.0 AAC
226	TL5021 MORRIS STREET	WESTSIDE	138.00	138.00	1	3.74	0	1	795.0 AAAC
227	TL5021 MORRIS STREET	WESTSIDE	138.00	138.00	1	1.39	0	2	795.0 ACSR/ 1590
228	TL5021 MORRIS STREET	WESTSIDE	138.00	138.00	1	0.14	0	1	477 ACSR
229	TL5025 La Pryor	Crystal City Extension	69.00	138.00	1	0.01	0	1	795 ACSS
230	TL5027 BARNEY DAVIS	PHARAOH	138.00	138.00	1	0.06	3	1	T2 795
231	TL5027 BARNEY DAVIS	PHARAOH	138.00	138.00	1	0.07	0	1	1590.0 ACSR
232	TL5029 ALICE	KINGSVILLE	138.00	138.00	2	15.88	0	1	477.0 ACSR
233	TL5029 ALICE	KINGSVILLE	138.00	138.00	1	0.70	0	1	477.0 ACSR
234	TL5029 ALICE	KINGSVILLE	138.00	138.00	2	5.90	0	1	795.0 ACSR

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235	TL5031 LON HILL	CITY OF ROBSTOWN	69.00	138.00	1	0.74	0	1	795.0 ACSR
236	TL5032 PHARAOH	AIRLINE	138.00	138.00	1	1.43	0	2	1590.0 ACSR
237	TL5032 PHARAOH	AIRLINE	138.00	138.00	3	0.12	0	2	1590.0 ACSR
238	TL5032 PHARAOH	AIRLINE	138.00	138.00	1	0.33	0	1	1590.0 ACSR
239	TL5058 NUECES BAY	DUPONT SS	138.00	138.00	1	1.55	0	1	795.0 ACSR
240	TL5058 NUECES BAY	DUPONT SS	138.00	138.00	2	11.25	0	1	795.0 ACSR
241	TL5078 NUECES BAY	WHITEPOINT	138.00	138.00	1	0.27	0	1	795.0 ACSS
242	TL5078 NUECES BAY	WHITEPOINT	138.00	138.00	1	3.05	0	1	795.0 ACSR
243	TL5078 NUECES BAY	WHITEPOINT	138.00	138.00	1	2.46	0	1	2x795.0 ACSR
244	TL5078 NUECES BAY	WHITEPOINT	138.00	138.00	2	7.63	0	1	795.0 ACSR
245	TL5061 MIDWAY PUMP TAP	TAFT	69.00	138.00	1	3.04	0	1	795.0 ACSR
246	TL5061 MIDWAY PUMP TAP	TAFT	69.00	138.00	2	0.13	0	1	795.0 ACSR
247	TL5061 MIDWAY PUMP TAP	TAFT	69.00	138.00	1	0.80	0	2	795.0 ACSR
248	TL5062 TAFT	SINTON	69.00	138.00	1	9.40	0	1	795.0 ACSR
249	TL5062 TAFT	SINTON	69.00	138.00	2	0.12	0	1	795.0 ACSR
250	TL5072 DUPONT SWITCHING STA	INGLESIDE	138.00	138.00	1	1.00	0	1	795.0 ACSR
251	TL5072 DUPONT SWITCHING STA	INGLESIDE	138.00	138.00	2	2.18	0	1	795.0 ACSR
252	TL5072 DUPONT SWITCHING STA	INGLESIDE	138.00	138.00	3	0.06	0	1	795.0 ACSR
253	TL5073 DUPONT SS	RINCON CKT#1	138.00	138.00	1	0.19	0	1	795.0 ACSR
254	TL5073 DUPONT SS	RINCON CKT#1	138.00	138.00	3	10.50	0	1	795.0 ACSR
255	TL5077 ARANSAS PASS	DUPONT SS	138.00	138.00	1	0.91	0	1	795.0 ACSR/AW
256	TL5077 ARANSAS PASS	DUPONT SS	138.00	138.00	2	3.96	0	1	795.0 ACSR/AW
257	TL5079 DUPONT SW.	PORTLAND	138.00	138.00	1	7.50	0	1	2x795.0 ACSR
258	TL5079 DUPONT SW.	PORTLAND	138.00	138.00	1	0.33	0	1	2x795.0 ACSS
259	TL5079 DUPONT SW.	PORTLAND	138.00	138.00	4	0.10	0	1	2X795 ACSR/AW
260	TL5082 ARANSAS PASS	ROCKPORT	69.00	138.00	1	0.15	0	1	795ACSR/AW
261	TL5086 HIGHWAY 9	NUECES BAY	69.00	138.00	1	1.33	0	1	795.0 AAC
262	TL5087 HIGHWAY 9	ARCADIA	138.00	138.00	1	3.18	0	1	1590.0 ACSR
263	TL5087 HIGHWAY 9	ARCADIA	138.00	138.00	1	3.18	0	1	1272 ACSR
264	TL5087 HIGHWAY 9	ARCADIA	138.00	138.00	1	1.20	0	1	1590.0 ACSR
265	TL5099 AIRLINE	SOUTHSIDE (WEST)	138.00	138.00	1	2.54	0	1	795.0 AAC
266	TL5099 AIRLINE	SOUTHSIDE (WEST)	138.00	138.00	1	0.04	0		795.0 ACSR/AW
267	TL5100 LGE/GPP	REYNOLDS SHERWIN	138.00	138.00	1	0.50	0	1	795.0 ACSR
268	TL5101 HOLLY	SOUTHSIDE	138.00	138.00	1	0.31	0	1	795.0 ACSR/AW
269	TL5101 HOLLY	SOUTHSIDE	138.00	138.00	2	1.49	0	1	795.0 ACSR
270	TL5105 DUPONT SS	ICP CKT#1	138.00	138.00	1	0.63	0	1	795.0 AAC
271	TL5106 FALFURIAS	NORTH EDINBURG	138.00	138.00	1	25.10	0	1	795.0 ACSR
272	TL5111 B M DAVIS	AIRLINE (WEST)	138.00	138.00	1	2.87	0	1	T2 795
273	TL5111 B M DAVIS	AIRLINE (WEST)	138.00	138.00	1	2.77	0	2	1590.0 ACSR
274	TL5111 B M DAVIS	AIRLINE (WEST)	138.00	138.00	3	3.05	0	2	1590.0 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)
275	TL5111 B M DAVIS	AIRLINE (WEST)	138.00	138.00	1	1.59	0	1	1590.0 ACSR
276	TL5112 BARNEY DAVIS	AIRLINE (EAST)	138.00	138.00	1	2.82	0	1	T2 795
277	TL5112 BARNEY DAVIS	AIRLINE (EAST)	138.00	138.00	3	1.92	0	2	1590.0 ACSR
278	TL5112 BARNEY DAVIS	AIRLINE (EAST)	138.00	138.00	1	4.78	0	2	1590.0 ACSR
279	TL5112 BARNEY DAVIS	AIRLINE (EAST)	138.00	138.00	1	0.41	0	1	1590.0 ACSR
280	TL5116 WEST OSO	WESTSIDE	138.00	138.00	1	1.59	0	1	1272.0 ACSR
281	TL5119 CELANESE	KLEBERG	138.00	138.00	1	6.09	0	1	795.0 ACSR
282	TL5120 Dupont Switching Station	OXY CHEMICAL	138.00	138.00	1	1.78	0	1	795.0 ACSR
283	TL5120 Dupont Switching Station	OXY CHEMICAL	138.00	138.00	1	0.21	0	1	795.0 ACSS
284	TL5123 DUPONT SS	ICP CKT#2	138.00	138.00	1	1.45	0	1	795.0 ACSR
285	TL5124 DUPONT SS	ICP CKT#1	138.00	138.00	1	0.91	0	1	795.0 AAC
286	TL5125 WEIL TRACT	WESTSIDE	138.00	138.00	1	5.11	0	1	1590.0 ACSR
287	TL5126 EQUISTAR	LON HILL	138.00	138.00	1	3.54	0	1	795.0 ACSR
288	TL5128 NUECES BAY	CITGO	138.00	138.00	1	1.06	0	1	795.0 AAC
289	TL5128 NUECES BAY	CITGO	138.00	138.00	3	0.67	0		795.0 ACSR
290	TL5135 CITGO WEST	LON HILL	138.00	138.00	1	0.66	0	1	795.0 ACSR
291	TL5135 CITGO WEST	LON HILL	138.00	138.00	2	2.19	0		
292	TL5136 DAVIS	NELSON SHARPE	138.00	138.00	2	12.24	0	1	795.0 ACSR
293	TL5140 CC PETRO CHEMICAL	MCKENZIE	138.00	138.00		11.50	0		477 ACSR
294	TL5140 CC PETRO CHEMICAL	MCKENZIE	138.00	138.00			0		795 ACSR
295	TL5141 AIRLINE	HOLLY	138.00	138.00	1	1.89	0	1	1590.0 ACSR
296	TL5141 AIRLINE	HOLLY	138.00	138.00	1	0.01	0	1	1590.0 ACSS
297	TL5141 AIRLINE	HOLLY	138.00	138.00	1	0.20	0	2	1949 ACCC
298	TL5142 RODD FIELD	CABANISS	138.00	138.00	1		0	1	1590.0 ACSR
299	TL5142 RODD FIELD	CABANISS	138.00	138.00	2	1.47	0	1	1590.0 ACSR
300	TL5142 RODD FIELD	CABANISS	138.00	138.00	2	2.80	0	1	1590 ACSS
301	TL5142 RODD FIELD	CABANISS	138.00	138.00	2	1.80	0	1	1949 ACCC
302	TL5143 CABANISS	WESTSIDE	138.00	138.00	2	1.19	0	1	1590 ACSS
303	TL5143 CABANISS	WESTSIDE	138.00	138.00	1	0.46	0	1	1590 ACCC
304	TL5149 LON C HILL	ORANGE GROVE	138.00	138.00	1	2.10	0	1	795.0 ACSR
305	TL5149 LON C HILL	ORANGE GROVE	138.00	138.00	2	11.48	0		1020 ACCC
306	TL5149 LON C HILL	ORANGE GROVE	138.00	138.00	3	11.27	0	2	1026 ACCC
307	TL5150 HOMEPORT	INGLESIDE	138.00	138.00	1	3.69	0	1	795.0 AAC
308	TL5150 HOMEPORT	INGLESIDE	138.00	138.00			0		795.0 ACSR
309	TL5155 DUPONT SWITCHING STA	GPP CIRCUIT 2	138.00	138.00	1	0.04	1	1	2x795.0 ACSR
310	TL5156 DUPONT SWITCHING STA	GPP CIRCUIT 1	138.00	138.00	1	1.29	0	1	2x795.0 ACSR
311	TL5160 WHITEPOINT	DUPONT Switching Station	138.00	138.00	3	1.71	0	2	795 ACSR
312	TL5160 WHITEPOINT	DUPONT Switching Station	138.00	138.00	1	0.47	0	2	795 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)
313	TL5160 WHITEPOINT	DUPONT Switching Station	138.00	138.00	1	5.83	0	2	1026 ACSR
314	TL5160 WHITEPOINT	DUPONT Switching Station	138.00	138.00	1	0.03	0	1	795 ACSR
315	TL5160 WHITEPOINT	DUPONT Switching Station	138.00	138.00	4	0.11	0	1	5000 SEGMENTAL OX
316	TL5165 WHITEPOINT	RINCON	138.00	138.00	1		3	2	1026 ACCC
317	TL5165 WHITEPOINT	RINCON	138.00	138.00	1	4.57	0	1	795 ACSS
318	TL5166 Whitepoint	Portland	138.00	138.00	1	2.79	0	1	2x795.0 ACSR/AW
319	TL5167 WHITEPOINT	DUPONT SW BUSS #2	138.00	138.00	1	0.74	0	1	1026 ACCC
320	TL5167 WHITEPOINT	DUPONT SW BUSS #2	138.00	138.00	1	0.29	0	1	795 ACSS
321	TL5167 WHITEPOINT	DUPONT SW BUSS #2	138.00	138.00	4	0.11	0	1	5000 SEGMENTAL OX
322	TL5178 JARDIN SUBSTATION	JARDIN SUBSTATION	138.00	138.00	1	0.03	0	1	795.0 ACSR
323	TL5179 LA PALMA	PALO ALTO (PUB)	138.00	138.00			0		
324	TL5187 HECKER	EXTENSION #1	138.00	138.00	1	0.52	0	2	795.0 ACSS
325	TL5188 BUNSEN	EXTENSION	138.00	138.00	2	0.73	0	2	959.6 ACSS
326	TL5189 CHAMPLIN	VALERO EAST	69.00	138.00	1	1.42	0	1	795 ACSS
327	TL5194 KEPLER	EF 90	69.00	138.00	3	0.04	0	1	477ACSR/AW
328	TL5195 TORTUGA	M&G 138kV EXTENSION	138.00	138.00	1	0.40	0	1	477 ACSR
329	TL5199 PHARR 138kV LOOP	M&G 138kV EXTENSION	138.00	138.00	1	2.20	0	2	959.6 ACSS/TW SUW
330	TL5201 HECKER	EXTENSION #2	138.00	138.00	1	0.53	0	2	795.0 ACSS
331	TL5202 HECKER	ALPINE	138.00	138.00	1	0.06	0	2	795.0 ACSR
332	TL5203 HECKER	CHENIERE (CUSTOMER STATION)	138.00	138.00	1	0.09	0	2	1590 ACSR Falcon
333	TL5206 MARCONI	SAN ROMAN	138.00	138.00	1	0.70	0	1	959ACSS/TW
334	TL5207 MELON CREEK EXTENSIO	SAN ROMAN	138.00	138.00	1	0.82	0	2	795 ACSS/AW
335	TL5208 LA PRYOR	UVALDE EXTENTION	69.00	138.00	1	0.06	0	1	795ACSR
336	TL5208 LA PRYOR	UVALDE EXTENTION	138.00	138.00	1	0.50	0	1	477.0 ACSR
337	TL5214 POESTA	THREE RIVERS	138.00	138.00	1	28.83	0	1	795 ACSS
338	TL5219 POESTA EXTENSION		69.00	138.00	1	0.60	0	1	795 ACSS
339	TL5221 Crystal City	Carrizo Springs (operating at 69kV)	69.00	138.00	1	12.58	0	1	795 ACSS
340	TL5222 HARLINGEN SS	RAYMONDVILLE #2	69.00	138.00	1	23.47	0	1	959.6 ACSS
341	TL5225 BEEVILLE	SINTON 138KV LINE	69.00	138.00	1	0.10	0	1	959.5 ACSS
342	TL5225 BEEVILLE	SINTON 138KV LINE	69.00	138.00	1	0.50	0	1	795 ACSS
343	TL5226 JOSLIN POI (IPP)	SINTON 138KV LINE	138.00	138.00	1	0.03	0	1	795ACSR
344	TL5227 MELON CREEK 138kV TA	SINTON 138KV LINE	138.00	138.00	1	1.82	0	1	795 ACSS/AW
345	TL5229 JOURDANTON	PLEASANTON	69.00	138.00	1	4.70	0	1	795 ACSS
346	TL5230 ROCKPORT	FULTON #1	69.00	138.00	1	7.66	0	1	795 ACSS
347	TL5231 BISHOP	STRATTON	69.00	138.00	1	4.80	0	1	795 ACSS/AW
348	TL5231 BISHOP	STRATTON	69.00	138.00	2	0.03	0	1	795 ACSS/AW

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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)
349	TL5232 ALICE	NORTH ELLA 138kV Line (operating at 69kV)	69.00	138.00	1	14.11	0	1	795 ACSS
350	TL5233 PREMONT	FALFURRIAS	69.00	138.00	1	12.43	0	1	795 ACSS
351	TL5233 PREMONT	FALFURRIAS	69.00	138.00	2	0.13	0	1	795 ACSS
352	TL5234 LA PRYOR	TURTLE CREEK	69.00	138.00	1	14.48	0	1	795 ACSS
353	TL5235 LA PRYOR	UVALDE	69.00	138.00	2	17.27	0	1	795ACSS
354	TL5236 REFUGIO	TATTON	138.00	138.00	1	21.94	0	1	795 ACSS/AW
355	TL5237 BANQUETE	STADIUM	69.00	138.00	1	17.64	0	1	795 ACSS
356	TL5238 CALALLEN STEC	BANQUETE	138.00	138.00	1	12.63	0	1	795 ACSS
357	TL5239 KNIPPA	SABINAL	69.00	138.00	1	2.51	0	1	795 ACSS
358	TL5240 UVALDE	KNIPPA	69.00	138.00	1	4.59	0	1	795 ACSS
359	TL5241 PALACIOS	BLESSING	69.00	138.00	1	9.90	0	1	795 ACSS/AW
360	TL5242 CARANCAHUA	PALACIOS	69.00	138.00	2	0.08	0	1	795 ACSS/AW
361	TL5242 CARANCAHUA	PALACIOS	69.00	138.00	1	13.40	0	1	795 ACSR/AW
362	TL5243 POINT COMFORT	CARANCAHUA	69.00	138.00	1	9.82	0	1	795 ACSS/AW
363	TL5247 COY CITY TAP	PLEASANTON	69.00	138.00	1	17.27	0	1	795 ACSS
364	TL5248 COY CITY	THREE RIVERS	69.00	138.00	1	22.97	0	1	795 ACSS
365	TL5249 SEAWALL	PORT ARANSAS	69.00	138.00	1	8.02	0	1	795 ACSS/AW
366	TL5249 SEAWALL	PORT ARANSAS	69.00	138.00	2	0.10	0	1	795 ACSS/AW
367	TL5249 SEAWALL	PORT ARANSAS	69.00	138.00	4	0.50	0	1	2-5000 CU XLPE
368	TL5250 Aransas Pass	Seawall (operating at 69kV)	69.00	138.00	1	3.10	0	1	795 ACSS
369	TL5251 GOLIAD	FANNIN	69.00	138.00	1	5.10	0	1	795 ACSS/AW
370	TL5253 HEARD TAP	REFUGIO	69.00	138.00	1	3.05	0	1	795 ACSS
371	TL5254 WOODSBORO	HEARD TAP	69.00	138.00	1	3.73	0	1	795 ACSS/AW
372	TL5255 BONNIEVIEW	WOODSBORO	69.00	138.00	1	5.80	0	1	795 ACSS/AW
373	TL5256 BONNIEVIEW	RINCON	69.00	138.00	1	12.60	0	1	795 ACSS/AW
374	TL5257 NORTH ELLA	PREMONT	138.00	138.00	1	10.49	0	1	795 ACSS
375	TL5258 PHARR STATCOM BUS TI	PREMONT	138.00	138.00	1	0.11	0	1	795 ACSS
376	TL5259 PHARR STATCOM BUS TI	PREMONT	138.00	138.00	1	0.18	0	1	795 ACSS
377	TL5260 RINCON	GREGORY	69.00	138.00	1	7.47	0	1	795 ACSS/AW
378	TL5261 BRACKETTVILLE	ESCONDIDO	138.00	138.00	1	45.40	0	1	795 ACSS
379	TL5262 CAMPWOOD	UVALDE	69.00	138.00	1	19.27	0	1	795 ACSS
380	TL5263 GREENLAKE	CARBIDE	69.00	138.00	1	2.22	0	1	795 ACSS/AW
381	TL5264 LA PALMA SVC BUS TIE	CARBIDE	138.00	138.00	1	0.11	0	1	795 ACSS
382	TL5265 LA PALMA SVC BUS TIE	CARBIDE	138.00	138.00	1	0.12	0	1	795 ACSS
383	TL5266 AIRLINE	NAVAL BASE TIE LINE	138.00	138.00	1	0.10	0	1	1590 ACSS
384	TL5267 Airline	Lunana	138.00	138.00	1	0.03	0	1	1590 ACSS
385	TL5268 Nelson Sharpe 345kV	Lunana	345.00	345.00	1	0.06	0	1	2X954 ACSR
386	TL5269 GOLIAD	BAEZ	69.00	138.00	1	24.90	0	1	795 ACSS
387	TL5270 NAVAL BASE	NORTH PADRE TAP	69.00	138.00	2	5.15	0	1	795 ACSS
388	TL5272 BUNSEN	TEXSTAR 138KV LINE	138.00	138.00	1	0.82	0	1	795 ACSS

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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)
389	TL5276 GIBBS SUBSTATION	GCGV #1 TIE LINE	138.00	138.00	2	0.04	0	1	795 AAC
390	TL5277 GIBBS SUBSTATION	GCGV #2 TIE LINE	138.00	138.00	2	0.04	0	1	795 AAC
391	TL5278 GIBBS SUBSTATION	GCGV #3 TIE LINE	138.00	138.00	2	0.02	0	1	795 AAC
392	TL5279 GIBBS SUBSTATION	GCGV #4 TIE LINE	138.00	138.00	2	0.02	0	1	795 AAC
393	TL5280 GODDARD	JARVIK (KARANKAWA I) TIE LI	345.00	345.00	1	0.02	0	1	2X954 ACSR/AW
394	TL5285 GIBBS EXTENSION	JARVIK (KARANKAWA I) TIE LI	138.00	138.00	1	0.92	0	2	2X795ACSS/AW
395	TL5286 PAVLOV EXTENSION	JARVIK (KARANKAWA I) TIE LI	138.00	138.00	1	0.65	0	2	795 ACSS
396	TL5287 Dupont SS	RUPLEY	138.00	138.00	1	0.04	0	1	795 ACSS
397	TL5289 VICTORIA	LEOPOLD	138.00	138.00	1	0.04	0	1	795 ACSS
398	TL5290 GODDARD	WELDER (KARANKAWA II) TIE L	345.00	345.00	1	0.02	0	1	2X954 ACSR/AW
399	TL5291 Charlotte	Jourdanton	69.00	138.00	1	10.30	0	1	795 ACSS
400	TL5292 KELVIN	CHALUPA 138KV TIE LINE	138.00	138.00	1	0.04	0	1	795 ACSS
401	TL5297 EDROY	MATHIS	69.00	138.00	1	13.87	0	1	795 ACSS
402	TL5298 Dilley	Charlotte	69.00	138.00	1	34.50	0	1	795 ACSS
403	TL5299 Asherton	McLean	138.00	138.00	1	0.04	0	1	795 ACSS
404	TL5304 GARZA	CONTINENTAL	69.00	138.00	1	0.06	0	1	795 ACSS
405	TL5305 Luna	Rayos Del Sol	138.00	138.00	1	0.10	0	1	795 ACSS
406	TL5306 Luna Extension	Rayos Del Sol	138.00	138.00	1	0.46	0	2	795 ACSS
407	TL5307 Esperanza Extension	Rayos Del Sol	138.00	138.00	1	0.60	0	2	795 ACSS
408	TL5313 Stewart Road 345kV	138kV Auto Trans Bus Tie No. 1	138.00	138.00	1	0.15	0	1	2-795 ACSS
409	TL5314 Stewart Road 345kV	138kV Auto Trans Bus Tie No. 2	138.00	138.00	1	0.15	0	1	2-795 ACSS
410	TL5316 Raymondsville #2	La Sara (STEC)	138.00	138.00	—	0.05	0	1	795 ACSR
411	TL5324 BAEZ	CHASE FIELD	69.00	138.00	1	0.40	0	1	795 ACSS
412	TL5331 LA PALMA	STEWART ROAD	69.00	138.00	1	0.20	0	1	795 ACSS
413	TL5342 Blessing	Clemville Sw. (STEC)	69.00	138.00	1	10.78	0	1	795 ACSS
414	TL5344 WEAVER ROAD	GREEN LAKE 138KV LINE	69.00	138.00	1	0.30	0	1	4/0 ACSR
415	TL5346 ODEM	SINTON 138KV LINE	69.00	138.00	1	0.05	0	1	ACSS/AW
416	TL5363 CHARTER	BRIGHTSIDE	138.00	138.00	1	0.74	0	1	795 ACSS
417	TL5364 LUNA	Vancourt 138kV Tie Line	138.00	138.00	1	0.10	0	1	795 ACSS
418	TL5366 JOSLIN	TRES BAHIAS	138.00	138.00	1	0.05	0	1	795 ACSS
419	TL5368 ROMA TAP	STARR	138.00	138.00	1	0.05	0	1	795 ACSS
420	TL5385 CLARKWOOD	CARINA BESS	138.00	138.00	1	0.02	0	1	795 ACSR
421	TL5412 FRONTERA SW	Frontera Energy Center #1	138.00	138.00	1	0.04	0	1	1272 ACSR
422	TL5413 FRONTERA SW	Frontera Energy Center #2	138.00	138.00	1	0.03	0	1	1272 ACSR
423	TL5414 FRONTERA SW	Frontera Energy Center #3	138.00	138.00	1	0.05	0	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)
424	TL7001 LAREDO	MILO ROAD	138.00	138.00	1	2.35	0	1	795.0 ACSR
425	TL7001 LAREDO	MILO ROAD	138.00	138.00	1	0.48	0	1	1020 ACCC
426	TL7001 LAREDO	MILO ROAD	138.00	138.00	1	0.43	0	1	2x795.0 ACSR
427	TL7003 CONOCO TAP	CONOCO	138.00	138.00	2	4.80	0	1	4/0 ACSR
428	TL7005 GANSO	EAGLE PASS	138.00	138.00	1	0.41	0	1	795 ACSS
429	TL7005A EAGLE PASS	ESCONDIDO CKT#2	138.00	138.00	2	1.14	0	1	336.0 ACSR
430	TL7005B ESCONDIDO	HAMILTON ROAD	138.00	138.00	2	10.13	0	1	336.0 ACSR
431	TL7006 EAGLE PASS HYDRO	GANSO	138.00	138.00	1	0.64	0	1	795 ACSS
432	TL7006 EAGLE PASS HYDRO	GANSO	138.00	138.00	2	0.04	0	1	336.0 ACSR
433	TL7007 MAVERICK	GANSO	138.00	138.00	2	1.87	0	1	336.0 ACSR
434	TL7007 MAVERICK	GANSO	138.00	138.00	1	0.46	0	1	795 ACSS
435	TL7008 HAMILTON ROAD PST	SONORA	138.00	138.00	2	66.52	0	1	477.0 ACSR
436	TL7008 HAMILTON ROAD PST	SONORA	138.00	138.00	1	0.35	0	1	795 ACSS
437	TL7008 HAMILTON ROAD PST	SONORA	138.00	138.00	1	0.30	0	1	959.6 ACSS/TW
438	TL7009 ASHERTON	WEST BATESVILLE	138.00	138.00	2	36.09	0	1	336.0 ACSR
439	TL7010 PLEASANTON	CPSB LEON CREEK	138.00	138.00	2	15.40	0	1	1020.0 ACCC/TW
440	TL7011 PLEASANTON	BIGFOOT	138.00	138.00	2	29.83	0	1	336.4 ACSR
441	TL 7012 MOORE	UVALDE	138.00	138.00	1	0.04	0	1	795 ACSS
442	TL 7012 MOORE	UVALDE	138.00	138.00	1	0.15	0	1	336 ACSR
443	TL7012A MOORE	MEC DOWNIE	138.00	138.00	2	41.03	0	1	336.4 ACSR
444	TL7012B UVALDE	MEC DOWNIE	138.00	138.00	2	9.34	0	1	336.4 ACSR
445	TL7016 FALFURRIAS	LOBO	138.00	138.00	1	26.96	0	1	2x795.0 ACSS
446	TL7016 FALFURRIAS	LOBO	138.00	138.00			0		795.0 ACSR
447	TL7017 BRUNI	CRESTONIO	138.00	138.00	1	14.80	0	1	795.0 ACSR
448	TL7018 LAREDO PLANT	DEL MAR	138.00	138.00	1	2.67	0	1	795.0 ACSR/AW
449	TL7019 ZAPATA	RANDADO	138.00	138.00	2	22.20	0	1	4/0 ACSR
450	TL7020A FALCON SWITCHING	FALCON DAM (US) CKT#2	138.00	138.00	2	4.50	0	1	4/0 ACSR
451	TL7020B FALCON SWITCHING	ZAPATA	138.00	138.00	1	25.86	4	1	795.0 ACSR
452	TL7021C LAREDO POWER PLANT	LAREDO VFT SOUTH	138.00	138.00	2	0.24	0	1	795.0 ACSR
453	TL7025 HEIGHTS	LAREDO CKT #1	138.00	138.00	1	4.40	0	1	795.0 AAAC
454	TL7025B HEIGHTS	LAREDO CKT #2	138.00	138.00	1	5.19	0	1	795.0 AAAC
455	TL7026 FREER	LOBO	69.00	138.00	1	1.09	0	1	2x795.0 ACSS
456	TL7026 FREER	LOBO	69.00	138.00	2	48.38	0		4/0 ACSR
457	TL7030 ENCINAL	COTULLA	138.00	138.00	1	29.05	0	1	795.0 ACSR
458	TL7030 ENCINAL	COTULLA	138.00	138.00	1	0.05	0	1	795 ACSS
459	TL7046 ASHERTON	DILLEY SS	138.00	138.00	2	15.98	0	1	795.0 ACSR
460	TL7047 ASHERTON	DILLEY SS	138.00	138.00	2	21.80	0	1	795.0 ACSR
461	TL7048 COTULLA	DILLEY SS	138.00	138.00	1	16.15	1	1	795.0 ACSR
462	TL7065 HAMILTON ROAD	PICACHO CKT#1 138KV LINE	138.00	138.00	1	8.81	0	1	795 ACSS
463	TL7066 PICACHO	AMISTAD HYDRO	138.00	138.00	2	6.40	0	1	4/0 ACSR

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464	TL7067 HAMILTON ROAD	PICACHO CKT#2	138.00	138.00	1	1.45	0	1	4/0 ACSR
465	TL7067 HAMILTON ROAD	PICACHO CKT#2	138.00	138.00	2	1.07	0		
466	TL7068 HAMILTON ROAD	PICACHO CKT#2	138.00	138.00	1	1.29	0	1	4/0 ACSR
467	TL7068 HAMILTON ROAD	PICACHO CKT#2	138.00	138.00	2	1.53	0		
468	TL7069 HAMILTON ROAD	PICACHO CKT#2	138.00	138.00	1	0.44	0	1	4/0 ACSR
469	TL7069 HAMILTON ROAD	PICACHO CKT#2	138.00	138.00	2	2.65	0		
470	TL7079 BIGFOOT	MOORE	138.00	138.00	1	6.08	0	1	795 ACSS
471	TL7081 EAGLE PASS	CFE PIEDRAS NEGRAS	138.00	138.00	1	1.33	0	1	477.0 ACSR
472	TL7082 ESCONDIDO	HAMILTON ROAD	138.00	138.00	2	41.21	0	1	336.0 ACSR
473	TL7086 UVALDE	WEST BATESVILLE	138.00	138.00	2	20.61	0	1	336.0 ACSR
474	TL7087 WEST BATESVILLE	MEC BATESVILLE	138.00	138.00	2	9.36	0	1	795.0 ACSR
475	TL7088 DILLEY SS	STEC SAN MIGUEL	138.00	138.00	1	47.54	0	1	795.0 ACSR
476	TL7088 DILLEY SS	STEC SAN MIGUEL	138.00	138.00	2		0		
477	TL7091 PICACHO	AMISTAD HYDRO	138.00	138.00	1	1.91	0	1	336.0 ACSR
478	TL7092B EAGLE PASS	ESCONDIDO CKT#1	138.00	138.00	1	0.32	0	1	4/0 ACSR
479	TL7092B EAGLE PASS	ESCONDIDO CKT#1	138.00	138.00	2	1.13	0		795.0 ACSR
480	TL7101 SANTO NINO	WORMSER Switching Station	138.00	138.00	1	0.30	0	1	795 ACSS
481	TL7102 RIO BRAVO	ZAPATA	138.00	138.00	1	27.48	3	1	795 ACSR
482	TL7102 RIO BRAVO	ZAPATA	138.00	138.00	1	0.23	0	1	4/0 ACSR
483	TL7105 WORMSER	RIO BRAVO	138.00	138.00	1	0.46	0	1	795.0 ACSR
484	TL7111 UNIVERSITY	WORMSER	138.00	138.00	1	1.74	0	1	795 ACSR
485	TL7111 UNIVERSITY	WORMSER	138.00	138.00	1	2.68	0	2	795 ACSR
486	TL7114 ENCINAL	WORMSER	138.00	138.00	1	40.77	0	1	795 ACSR
487	TL7114 ENCINAL	WORMSER	138.00	138.00	1	8.43	0	2	795 ACSR
488	TL7114 ENCINAL	WORMSER	138.00	138.00	1	0.27	0	1	795 ACSR/AW
489	TL7115B UNIVERSITY	WORMSER	138.00	138.00	1	9.99	0	1	795.0 ACSR
490	TL7117 ASHERTON	NORTH LAREDO	138.00	138.00	1	6.95	0	1	366.4 ACSR
491	TL7117 ASHERTON	NORTH LAREDO	138.00	138.00	2	56.69	0		795.0 ACSR
492	TL7123 SIERRA VISTA	WORMSER	138.00	138.00	1	1.11	0	1	795.0 ACSR
493	TL7123 SIERRA VISTA	WORMSER	138.00	138.00	1	1.76	0	2	795.0 ACSR
494	TL7124 EL GATO	GOOLIE/SOUIX RD	138.00	138.00	1	5.30	0	1	795.0 ACSS
495	TL7125 SOUTH MCALLEN	STEWART ROAD	138.00	138.00	1	3.70	0	1	1590 ACSS
496	TL7125 SOUTH MCALLEN	STEWART ROAD	138.00	138.00	1	2.14	0	2	795.0 ACSS
497	TL7125 SOUTH MCALLEN	STEWART ROAD	138.00	138.00	1	5.96	0	1	795.0 ACSS
498	TL7138 PILONCILLO	PRANCH #1	138.00	138.00	1	0.06	0	1	795 ACSR
499	TL7141 BRACKETVILLE	BUS TIE #1	138.00	138.00	1	0.11	0	1	795 ACSS
500	TL7144 ASHERTON	CARRIZO SPRINGS	69.00	138.00	1	8.36	0	1	959.6ACSS/TW

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501	TL5224 BRACKETVILLE	BUS TIE #2	138.00	138.00	1	0.13	0	1	795 ACSS
502	TL5185 KENEDY SWITCHING STA	TULETA	138.00	138.00	1	19.33	0	2	959 ACSR/TW
503	TL5180 KENEDY SWITCHING STA	PETTUS	138.00	138.00	1	19.33	0	2	959 ACSR/TW
504	TL5261 BRACKETTVILLE	ESCONDIDO	138.00	138.00			0		
505	TL5209 BONILLA	LADEKIDDE	345.00	345.00			0		
506	TL5264 LA PALMA SVC	138KV BUS TIE #1	138.00	138.00			0		
507	TL5265 LA PALMA SVC	138KV BUS TIE #2	138.00	138.00			0		
508	69 KV for AEPTC	69 KV for AEPTC	69.00	69.00	—	768.95	0		
509	AEP TEXAS NORTH	AEP TEXAS NORTH							
510	TL125A ABILENE MULBERRY	BLUFF CREEK SS	345.00	345.00	2	26.50	0	1	2x795.0 ACSR
511	TL125B BLUFF CREEK SS	SAN ANGELO RED CREEK	345.00	345.00	2	49.56	0	1	2x795.0 ACSR
512	TL126 Mulberry Creek	Oklaunion	345.00	345.00	1	0.22	0	1	2-795 ACSR
513	TL126 Mulberry Creek	Oklaunion	345.00	345.00	2	115.65	0	1	2x795 ACSR
514	TL131 OKLAUNION	TU FISHER ROAD	345.00	345.00	2	28.81	0	1	2x795.0 ACSR
515	TL131 OKLAUNION	TU FISHER ROAD	345.00	345.00	1	1.60	0	1	2x795.0 ACSR
516	TL324 OKLAUNION DC TIE	DC TERMINAL NORTH (SPP)	345.00	345.00	1	0.02	0	1	1926.9KCM ACSR
517	TL325 OKLAUNION DC TIE	DC TERMINAL SOUTH (ERC)	345.00	345.00	1	0.02	0	1	1926.9KCM ACSR
518	TL407 SOLSTICE	BAKERSFIELD	345.00	345.00	3	35.50	0	1	2-1590 ACSS
519	TL423 SOLSTICE	SAND LAKE (ONCOR)	345.00	345.00	3	22.60	0	2	2-1590 ACSS
520	TL467 Perigee	Apogee	345.00	345.00	1	0.04	0	1	2-795 ACSR
521	TL001 Leon	Eskota	138.00	138.00	2	3.13	0	1	4/0 ACSR
522	TL001 Leon	Eskota	138.00	138.00	2	32.16	0	1	477.0 ACSR
523	TL028 ABILENE NORTHWEST	ANSON	69.00	138.00	1	1.63	0	1	795 ACSS/AW
524	TL031 SANTA ANNA	BROWNWOOD	138.00	138.00	1	7.29	0	1	795.0 ACSR
525	TL033 EDEN	YELLOWJACKET	69.00	138.00	1	0.11	0	1	795 ACSS
526	TL038 San Angelo	Sterling City (Interconnect TESCo) - Tmgren 69KV Line	69.00	138.00	1	0.15	0	1	795 ACSS
527	TL048 MCCAMEY - MCELROY	CRANE GULF 1&2	69.00	138.00	1	0.32	0	1	795 ACSS
528	TL050 RIO PECOS	FORT STOCKTON	138.00	138.00	2	35.39	0	1	477.0 ACSR
529	TL050 RIO PECOS	FORT STOCKTON	138.00	138.00	1	0.13	0	1	795.0 ACSS
530	TL051 EAST MUNDAY	PADUCAH CLARE STREET	138.00	138.00	1	3.20	0	1	477.0 ACSR
531	TL051 EAST MUNDAY	PADUCAH CLARE STREET	138.00	138.00	2	59.08	0		
532	TL051 EAST MUNDAY	PADUCAH CLARE STREET	138.00	138.00	1	0.40	0	1	T2-795.0 ACSR
533	TL064A EAST MUNDAY	LAKE PAULINE	138.00	138.00	2	56.97	0	1	2x4/0 ACSR
534	TL064B EAST MUNDAY	PAINT CREEK WEST#1	138.00	138.00	2	25.96	0	1	397.0 ACSR

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535	TL066A FORT PHANTOM	PAINT CREEK	138.00	138.00	2	38.73	0	1	1272.0 AAC
536	TL066A FORT PHANTOM	PAINT CREEK	138.00	138.00	3	0.48	0		477.0 ACSR
537	TL066B CALIFORNIA CREEK TAP	CALIFORNIA CREEK	138.00	138.00	2	0.02	0	1	4/0 ACSR
538	TL070 ABILENE NORTHWEST	OAK CREEK 138KV LINE	138.00	138.00	2	47.01	0	1	397.0 ACSR
539	TL070 ABILENE NORTHWEST	OAK CREEK 138KV LINE	138.00	138.00	2	5.21	0	1	795.0 ACSR
540	TL072 ABILENE NORTHWEST	PAINT CREEK	138.00	138.00	2	43.94	0	1	477.0 ACSR
541	TL072 ABILENE NORTHWEST	PAINT CREEK	138.00	138.00	1	0.28	0	1	477.0 ACSR
542	TL077 BALLINGER	OAK CREEK	138.00	138.00	1	0.28	0	1	795 ACSS
543	TL077 BALLINGER	OAK CREEK	138.00	138.00	2	30.85	0	1	397.0 ACSR
544	TL077 BALLINGER	OAK CREEK	138.00	138.00	—		0		477.0 ACSR
545	TL079A OAK CREEK	SAN ANGELO RED CREEK	138.00	138.00	1	3.21	0	2	2x795.0 ACSS
546	TL079A OAK CREEK	SAN ANGELO RED CREEK	138.00	138.00	2	33.71	0		397.0 ACSR
547	TL079A OAK CREEK	SAN ANGELO RED CREEK	138.00	138.00	1	0.06	0	1	795 ACSS
548	TL079B NORTH SAN ANGELO	SAN ANGELO RED CREEK	138.00	138.00	1	0.64	0	1	795.0 ACSR
549	TL079B NORTH SAN ANGELO	SAN ANGELO RED CREEK	138.00	138.00	2	8.96	0		
550	TL079C SAN ANGELO CONCHO	SAN ANGELO RED CREEK	138.00	138.00	1	2.07	0	1	795.0 ACSR
551	TL079C SAN ANGELO CONCHO	SAN ANGELO RED CREEK	138.00	138.00	2	7.66	0		
552	TL080 ALPINE	FORT STOCKTON	69.00	138.00	1	0.15	0	1	477ACSR
553	TL082 ABILENE SOUTH	BLUFF CREEK	138.00	138.00	2	17.60	0	1	1020.0 ACCC/TW
554	TL082 ABILENE SOUTH	BLUFF CREEK	138.00	138.00	1	2.20	0	2	2x795.0 ACSS
555	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	4.67	0	1	795.0 ACSR
556	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	4.70	0	1	795 ACSR
557	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	0.55	0	1	795.0 ACSR
558	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	2.44	0	1	795 ACSR
559	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	0.14	0	1	795 ACSS
560	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	3	0.50	0	1	1272.0 AAC
561	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	3	0.50	0	1	1272.0 ACSR
562	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	0.10	0	1	1272.0 AAC
563	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	5.50	0	1	1272 AAC
564	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	8.50	0	1	2x795 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)
565	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	3	0.53	0	1	1272 AAC
566	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	3	0.53	0	1	1272 ACSR
567	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	0.54	0	1	1272 ACSS
568	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	8.65	0	1	2x477 ACSR
569	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	2.10	0	1	795 ACSR
570	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	3	0.21	0	1	2x477 ACSR
571	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	2.78	0	1	795 ACSR
572	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	3.81	0	2	795 ACSR
573	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	5.67	0	1	1272 ACSR
574	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	0.16	0	1	1272.0 ACSR
575	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	3.30	0	1	(2) 795.0 ACSR
576	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	3.30	0	1	477 ACSR
577	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	0.11	0		795 ACSS
578	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	3.60	0	1	795.0 ACSR
579	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	1.00	0	1	795 ACSR
580	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	2	4.80	0	1	795 ACSR
581	TL083 ABILENE 138KV LOOP	TAYLOR	138.00	138.00	1	0.95	0		795.0 ACSR
582	TL084A SAN ANGELO CONCHO	SAN ANGELO POWER STATION	138.00	138.00	2	5.93	0	1	477.0 ACSR
583	TL084A SAN ANGELO CONCHO	SAN ANGELO POWER STATION	138.00	138.00	3	0.16	0		
584	TL084A SAN ANGELO CONCHO	SAN ANGELO POWER STATION	138.00	138.00	1	0.12	0		1590 ACSR
585	TL084B SOUTH ANGELO TAP	SOUTH ANGELO	138.00	138.00	3	1.00	0	1	4/0 ACSR
586	TL085 SAN ANGELO	BIG LAKE	138.00	138.00	2	54.90	0	1	477.0 ACSR
587	TL085 SAN ANGELO	BIG LAKE	138.00	138.00	1	0.02	0	1	795.0 ACSR
588	TL086 BIG LAKE	N MCCAMEY	138.00	138.00	2	35.95	0	1	477.0 ACSR
589	TL086 BIG LAKE	N MCCAMEY	138.00	138.00	2	10.30	0	1	956.6 ACSS
590	TL086 BIG LAKE	N MCCAMEY	138.00	138.00	1	0.73	0	1	795 ACSS
591	TL086 BIG LAKE	N MCCAMEY	138.00	138.00	2	0.09	0	1	795.0 ACSS
592	TL087 LAKE PAULINE	VERNON CKT #2	138.00	138.00	2	23.44	0	1	477.0 ACSR
593	TL088A SAN ANGELO POWER	SAN ANGELO RED CREEK	138.00	138.00	1	1.29	0	1	477.0 ACSR
594	TL088A SAN ANGELO POWER	SAN ANGELO RED CREEK	138.00	138.00	2	17.33	0	1	477.0 ACSR
595	TL088B BALLINGER	SAN ANGELO RED CREEK	138.00	138.00	1	1.29	0	1	477.0 ACSR

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596	TL088B BALLINGER	SAN ANGELO RED CREEK	138.00	138.00	2	30.31	0	1	477.0 ACSR
597	TL089 SAN ANGELO	VAL VERDE	138.00	138.00	2	21.23	0	1	477.0 ACSR
598	TL089 SAN ANGELO	VAL VERDE	138.00	138.00	1	0.22	0	1	795 ACSS
599	TL089 SAN ANGELO	VAL VERDE	138.00	138.00	1	0.55	0	1	477.0 ACSR
600	TL089A ELDORADO LIVE OAK	SAN ANGELO POWER STATION	138.00	138.00	2	38.23	0	1	477.0 ACSR
601	TL089B ELDORADO LIVE OAK	SONORA CKT#2	138.00	138.00	2	22.07	0	1	477.0 ACSR
602	TL090 ASPERMONT	PAINT CREEK	138.00	138.00	2	39.74	0	1	477.0 ACSR
603	TL092 RIO PECOS	CRANE	138.00	138.00	2	22.29	0	1	636.0 ACSR
604	TL092 RIO PECOS	CRANE	138.00	138.00	1	0.81	0	1	2x795.0 ACSR
605	TL092 RIO PECOS	CRANE	138.00	138.00	1	0.21	0		636 ACSR
606	TL092B TEXAS NEW MEXICO TAP	CRANE TAP #2	69.00	138.00	1	0.10	0	1	4/0 ACSR
607	TL093 SAN ANGELO	MENARD	138.00	138.00	3	0.36	0	2	477 ACSR
608	TL093 SAN ANGELO	MENARD	138.00	138.00	2	54.77	0	1	477 ACSR
609	TL093 SAN ANGELO	MENARD	138.00	138.00	3	0.15	0	1	336 ACSR
610	TL093 SAN ANGELO	MENARD	138.00	138.00	1	0.36	0	1	795.0 ACSS
611	TL094 PUTNAM	LEON CKT #2	138.00	138.00	2	21.93	0	1	4/0 ACSR
612	TL094 PUTNAM	LEON CKT #2	138.00	138.00	—		0		477.0 ACSR
613	TL095 SAN ANGELO COLLEGE	SAN ANGELO POWER STATION	138.00	138.00	2	2.75	0	1	795.0 ACSR
614	HILLS	SAN ANGELO POWER STATION	138.00	138.00	—		0		0
615	TL097 EAST MUNDAY	PAINT CREEK EAST#2	138.00	138.00	2	25.37	0	1	477.0 ACSR
616	TL100 BARRILLA JUNCTION	FORT STOCKTON PLANT	138.00	138.00	1	25.56	0	1	477.0 ACSR
617	TL111 ASPERMONT	SPUR	138.00	138.00	1	10.19	0	1	477.0 ACSR
618	TL111 ASPERMONT	SPUR	138.00	138.00	2	35.36	0		
619	TL113 ALAMITO CREEK	BARRILLA JUNCTION	138.00	138.00	1	0.32	0	1	477.0 ACSR
620	TL113 ALAMITO CREEK	BARRILLA JUNCTION	138.00	138.00	2	66.89	0		477 ACSR
621	TL113 ALAMITO CREEK	BARRILLA JUNCTION	138.00	138.00	1	0.10	0		795 ACSS
622	TL117 NORTH SAN ANGELO	SAN ANGELO COLLEGE HILLS	138.00	138.00	1	2.10	0	1	795.0 ACSR
623	TL117 NORTH SAN ANGELO	SAN ANGELO COLLEGE HILLS	138.00	138.00	2	6.48	0		
624	TL120A CEDAR HILL	OAK CREEK	138.00	138.00	2	26.26	0	1	4/0 ACSR
625	TL120A CEDAR HILL	OAK CREEK	138.00	138.00	1	0.09	0	1	959.6 ACSS
626	TL120B FORT CHADBOURNE TAP	FORT CHADBOURNE	138.00	138.00	2	0.02	0	1	4/0 ACSR
627	TL122 ABILENE MULBERRY	ABILENE NORTHWEST	138.00	138.00	2	2.59	0	1	1272.0 AAC
628	TL122 ABILENE MULBERRY	ABILENE NORTHWEST	138.00	138.00	—		0		1272.0 ACSR
629	TL123 MENARD	FORT MASON (LCRA)	138.00	138.00	1	1.05	0	1	477.0 ACSR
630	TL123 MENARD	FORT MASON (LCRA)	138.00	138.00	2	37.27	0		795 ACSS
631	TL124 FORT MASON (LCRA)	GILLESPIE COUNTY LINE	138.00	138.00	2	22.87	0	1	477.0 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)
632	TL124 FORT MASON (LCRA)	GILLESPIE COUNTY LINE	138.00	138.00	1	0.05	0	1	795 ACSS
633	TL127A BALLINGER	SANTA ANNA CKT #1	138.00	138.00	1	0.56	0	1	477.0 ACSR
634	TL127A BALLINGER	SANTA ANNA CKT #1	138.00	138.00	2	37.82	0		
635	TL127B EAST COLEMAN TAP	EAST COLEMAN	138.00	138.00	2	2.98	0	1	477.0 ACSR
636	TL128 OKLAUNION	VERNON	138.00	138.00	1	2.59	0	1	795.0 ACSR
637	TL128 OKLAUNION	VERNON	138.00	138.00	2	6.72	0		
638	TL129 ABILENE ELM CREEK	ABILENE MULBERRY CREEK	138.00	138.00	1	0.52	0	1	1272.0 AAC
639	TL129 ABILENE ELM CREEK	ABILENE MULBERRY CREEK	138.00	138.00	2	5.19	0		
640	TL133 OKLAUNION	SOUTHWEST VERNON	138.00	138.00	2	6.98	0	1	795.0 ACSR
641	TL133 OKLAUNION	SOUTHWEST VERNON	138.00	138.00	1	0.48	0	1	795.0 ACSR
642	TL136 SPUR	SUN	138.00	138.00	1	0.31	0	1	795.0 ACSR
643	TL136 SPUR	SUN	138.00	138.00	2	17.48	0		
644	TL138 PADUCAH CLARE STREET	WEST CHILDRESS	138.00	138.00	1	1.87	0	1	477.0 ACSR
645	TL138 PADUCAH CLARE STREET	WEST CHILDRESS	138.00	138.00	2	29.55	0		
646	TL140 SOLSTICE	YUCCA DRIVE (ONCOR)	138.00	138.00	1	0.05	0	1	477 ACSR
647	TL140 SOLSTICE	YUCCA DRIVE (ONCOR)	138.00	138.00	1	35.57	0	1	2x795 ACSS
648	TL141 FRIEND RANCH	CARVER	138.00	138.00	1	32.85	0	1	477.0 ACSR
649	TL204 STERLING-SUN JAMESON	ROBERT LEE - STERLING	69.00	138.00	1	0.08	0	1	959.6ACSS/TW
650	TL242 BIG LAKE	FRIEND RANCH	138.00	138.00	1	39.63	0	1	477.0 ACSR
651	TL242 BIG LAKE	FRIEND RANCH	138.00	138.00	1	0.40	0	2	959 ACSR/TW
652	TL243 LCRA NORTH MCCAMEY	NORTH MCCAMEY	138.00	138.00	1	0.19	0	1	795.0 ACSR
653	TL310 BLUFF CREEK	BUFFALO GAP	138.00	138.00	1	2.04	0	1	2x795.0 ACSS
654	TL311 BLUFF CREEK	EXTENSION	345.00	345.00	1	0.45	0	2	2x795.0 ACSR
655	TL319 GONZALES	ACACIA	69.00	138.00	1	2.40	0	1	795.0 ACSR
656	TL321 ESMERALDA	YUCCA	138.00	138.00	3	14.80	0	1	4/0ACSR
657	TL322 SAN ANGELO	RUSTHILL #1	69.00	138.00	1	0.02	0	1	1590 ACSR
658	TL323 SAN ANGELO CONCHO	RUSTHILL #2	138.00	138.00	1	0.17	0	1	1590 ACSR
659	TL327 SANTA RITA	EXTENSION	69.00	138.00	1	0.17	0	1	2/0 ACSR
660	TL353 DINNY	WEST YATES	69.00	138.00	1	3.19	0	1	959 ACSS/TW
661	TL329 BARRILLA JUNCTION	SOLSTICE	138.00	138.00	1	0.20	0	1	2x956.6 ACSS
662	TL330 SOLSTICE	CLOVIS	138.00	138.00	1	4.50	0	1	795.0 ACSS
663	TL331 N BRADY	BRADY CITY	69.00	138.00	1	0.90	0	2	959 ACSR/TW
664	TL332 HEARTLAND 138KV EXTEN	BRADY CITY	69.00	138.00	1	0.73	0	1	ACSR/TW
665	TL333 ABILENE NORTHWEST	ELY	69.00	138.00	1	8.25	0	1	477ACSR
666	TL334 ALAMITO CREEK	MARFA	69.00	138.00	1	0.58	0	1	959 ACSS/TW
667	TL335 MUNDAY	POINTER	69.00	138.00	1	5.75	0	1	959 ACSR/TW

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)
668	TL336 HEARTLAND	YELLOWJACKET 138KV LINE	69.00	138.00	1	18.80	0	1	959 ACSR
669	TL337 CASSAVA	YUCCA	138.00	138.00	1	11.90	0	1	397ACSR/T2
670	TL338 SOLSTICE	HOVEY	138.00	138.00	1	0.14	0	1	477 ACSR
671	TL338 SOLSTICE	HOVEY	138.00	138.00	1	0.10	0	1	477 ACSR
672	TL339 HENDRICK 138KV	HAIRPIN	138.00	138.00	1	0.68	0	2	795ACSS
673	TL340 ALBANY FOUNDRY	HULLTOWN	69.00	138.00	1	9.50	0	1	795 ACSS/AW
674	TL341 HULLTOWN	PUTNAM	69.00	138.00	1	13.30	0	1	795 ACSS
675	TL342 LOTEBUSH	ENSTOR HACBERRY DRAW	138.00	138.00	1	0.04	0	1	477 ACSR
676	TL343 BISON	POWELL FIELD 138KV TAP	69.00	138.00	1	6.80	0	1	4/0ACSR
677	TL344 BISON	OZONA	69.00	138.00	1	0.06	0	1	795.0 ACSS
678	TL345 ALBANY	FORT GRIFFIN	69.00	138.00	1	0.86	0	1	795 ACSS/AW
679	TL346 BIG LAKE	SAN ANGELO MATHIS FIELD	69.00	138.00	1	16.50	0	1	795 ACSS
680	TL348 CROWELL	MUNDAY	69.00	138.00	1	3.80	0	1	4/0 ACSR
681	TL348 CROWELL	MUNDAY	69.00	138.00	1	25.50	0	1	2x477 ACSR
682	TL349 JAYTAN	ROTAN	69.00	138.00	1	20.82	0	1	795 ACSS/TW
683	TL349 JAYTAN	ROTAN	69.00	138.00	1	20.99	0	1	477.0 ACSR
684	TL350 ALPINE	BARRILLA JUNCTION	69.00	138.00	1	49.34	0	1	795 ACSS
685	TL351 ABILENE SOUTH	SAWGRASS	69.00	138.00	1	1.95	0	1	795 ACSS
686	TL352 CACTUS	FORT LANCASTER	69.00	138.00	1	9.20	0	1	956.6 ACSS
687	TL354 QUAINT 138kV	EXTENSION	69.00	138.00	1	0.27	0	2	795 ACSS/AW
688	TL356 BRONCO 138KV	EXTENSION	69.00	138.00	1	0.29	0	1	795 ACSS
689	TL358 FORT GRIFFIN	RAINEY CREEK	69.00	138.00	1	0.37	0	1	795 ACSS/AW
690	TL359 ALBANY FOUNDRY	FORT GRIFFIN	69.00	138.00	1	4.71	0	1	795 ACSS
691	TL360 SAGE	OLLIN	69.00	138.00	1	2.80	0	1	795.0 ACSS
692	TL361 KINNISON	CRANE	69.00	138.00	1	1.10	0	1	795.0 ACSS
693	TL362 CRANE	MCELROY	69.00	138.00	1	2.30	0	1	795.0 ACSS
694	TL363 ABILENE NORTHWEST	ANSON 138KV LINE	69.00	138.00	1	19.39	0	1	795 ACSS
695	TL363 ABILENE NORTHWEST	ANSON	69.00	138.00	1	1.74	0	1	795 ACSS/AW
696	TL363 ABILENE NORTHWEST	ANSON	69.00	138.00	1	0.10	0	1	4/0 ACSR
697	TL364 MASON	FORT MASON	138.00	138.00	1	0.15	0	1	795.0 ACSS
698	TL365 ABILENE NORTHWEST	ELM CREEK (EAST)	69.00	138.00	1	3.10	0	1	795 ACSS
699	TL366 HENDRICK POI (OCI)	ELM CREEK (EAST)	138.00	138.00	1	0.03	0	1	477ACSR
700	TL367 BENJAMIN	TARDIS	138.00	138.00	1	7.69	0	1	T2-795 ACSR
701	TL368 Benjamin	Gyp	138.00	138.00	1	9.53	0	1	795 ACSR
702	TL369 Sonora	Carver	69.00	138.00	1	0.40	0	1	795 ACSS
703	TL370 LYNX	RIO PECOS	138.00	138.00	1	2.05	0	1	2x795 ACSS
704	TL371 Woodward #2 Tap	RIO PECOS	138.00	138.00	1	0.05	0	1	795 ACSS

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)
705	TL372 WOODWARD #1 138KV TAP	RIO PECOS	138.00	138.00	1	0.33	0	1	795.0 ACSS
706	TL373 DERRICK	OWLS	69.00	138.00	1	4.24	0	1	795 ACSS
707	TL374 ELY TAP	ESKOTA 138KV LINE	69.00	138.00	1	42.35	0	1	T2-477 ACSR
708	TL375 BISON	POWELL FIELD 138KV TAP	69.00	138.00	1	7.26	0	1	795.0 ACSS
709	TL377 BIG LAKE	BISON	69.00	138.00	1	10.43	0	1	795.0 ACSS
710	TL378 HASKELL TAP	PAINT CREEK	69.00	138.00	1	0.11	1	1	477.0 ACSR
711	TL379 ANSON	PAINT CREEK	69.00	138.00	1	39.40	0	1	T2-477 ACSR
712	TL380 COLLEGE HILLS WEST	BURMA	69.00	138.00	1	10.38	0	1	795.0 ACSS
713	TL382 ONYX TAP	BELKNAP 138KV LINE	69.00	138.00	1	8.01	0	1	T2-477 ACSR
714	TL383 RAINEY CREEK	BELKNAP 138KV LINE	69.00	138.00	1	8.66	0	1	T2-477 ACSR
715	TL385 Pecos Valley	FORT STOCKTON SW	138.00	138.00	1	19.35	0	1	795.0 ACSS
716	TL386 BALLINGER	CONCHO 138KV LINE	69.00	138.00	1	16.04	0	1	795 ACSS
717	TL387 PECOS VALLEY	RIO PECOS	138.00	138.00	1	26.14	0	1	795 ACSS
718	TL388 MILES	BRONTE ATLANTIC	69.00	138.00	1	17.70	0	1	795 ACSS
719	TL389 BRONTE	BRONTE ATLANTIC	69.00	138.00	1	3.70	0	1	795.0 ACSS
720	TL390 ROBERT LEE	BRONTE	69.00	138.00	1	8.60	0	1	795.0 ACSS
721	TL392 KIRKLAND	CHILRESS 138KV LINE	69.00	138.00	1	5.61	0	1	T2-477 ACSR
722	TL393 QUANAH	KIRKLAND GODDLETT 138KV LIN	69.00	138.00	1	17.35	0	1	477.0 ACSR
723	TL394 SANTA ANNA	CROSS PLAINS	69.00	138.00	1	28.58	0	1	795.0 ACSS
724	TL395 SAN ANGELO CONCHO	ELDORADO LIVE OAK	69.00	138.00	1	35.61	0	1	795.0 ACSS
725	TL395 SAN ANGELO CONCHO	ELDORADO LIVE OAK	69.00	138.00	1	8.01	0	2	795.0 ACSS
726	TL396 LAKE PAULINE	CHILLICOTHE	69.00	138.00	1	9.97	0	1	T2 477.0 ACSR
727	TL396 LAKE PAULINE	CHILLICOTHE	69.00	138.00	1	2.00	0	2	T2 477.0 ACSR
728	TL397 CHILLICOTHE	VERNON	69.00	138.00	1	14.24	0	1	T2 477.0 ACSR
729	TL398 Yellowjacket	Junction	69.00	138.00	1	27.58	0	1	795 ACSS
730	TL399 BALLINGER	EDEN 138KV LINE	69.00	138.00	1	34.87	0	1	795 ACSS
731	TL400 CEDAR HILL ROBERT LEE	ROBERT LEE CEDAR HILL	69.00	138.00	1	21.58	0	1	795 ACSS
732	TL401 FRIEND RANCH	SONORA #2	69.00	138.00	1	28.01	0	1	795.0 ACSS
733	TL401 FRIEND RANCH	SONORA #2	69.00	138.00	1	0.33	0	2	795.0 ACSS
734	TL402 BRONCO	LASSO	69.00	138.00	1	0.10	0	1	795 ACSS
735	TL403 Wolfgang	Mozart Wind Farm	69.00	138.00	1	0.07	0	1	795.0 ACSS
736	TL404 TREADWELL	CACTUS FLATS	138.00	138.00	1	0.14	0	1	795.0 ACSR
737	TL406 Rio Pecos	Horse Crossing (LCRA)	138.00	138.00	1	0.11	0	1	795 ACSR
738	TL408 SONORA	ELDORADO LIVE OAK	69.00	138.00	1	2.40	0	1	795 ACSS
739	TL410 CHERRY CREEK 138KV EX	Horse Crossing (LCRA)	69.00	138.00	1	0.87	0	1	795.0 ACSS
740	TL410 CHERRY CREEK 138KV EX	Horse Crossing (LCRA)	69.00	138.00	1	0.17	0	1	2/0 ACSR
741	TL411 SARAGOSA	SOLSTICE (SOUTH)	138.00	138.00	1	18.70	0	1	795.0 ACSS
742	TL412 LOTEBUSH	BROZOS MIDSTREAM	138.00	138.00	1	0.04	0	1	959.6 ACSS/TW
743	TL413 LOTEBUSH	ARROWHEAD	138.00	138.00	1	0.04	0	1	1926.9 ACSR/TW
744	TL414 LOTEBUSH	NW COYANOSA	138.00	138.00	1	0.06	0	2	959.6 ACSS/TW

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)
745	TL416 CRYO	SARGOSA	138.00	138.00	1	4.70	0	1	795 ACSS
746	TL417 Solstice	Ft Stockton SW 138kV Line	138.00	138.00	1	16.50	0	1	795 ACSS
747	TL418 CRYO	DIAMOND (APACHE) EXTENSION	138.00	138.00	1	0.08	0	1	795 ACSS
748	TL419 BIG LAKE	CASSAVA 138KV LINE	69.00	138.00	1	17.70	0	1	795 ACSS
749	TL420 MERTZON	MATHIS FIELD	69.00	138.00	1	23.52	0	1	795 ACSS
750	TL420 MERTZON	MATHIS FIELD	69.00	138.00	1	0.08	0	1	1026 ACCC
751	TL422 CROSSOVER 138KV TAP	MATHIS FIELD	138.00	138.00	1	0.09	0	1	795.0 ACSS
752	TL424 PIG CREEK	Tarbush (TNMP)	138.00	138.00	1	0.04	0	1	795 ACSS
753	TL428 PIG CREEK	TAYGETE 138KV TIE LINE	138.00	138.00	1	0.04	0	1	795 ACSS
754	TL429 San Angelo Concho	Mathis Field	69.00	138.00	1	0.01	0	1	795 ACSS
755	TL430 LYNX	SOAPTREE (TNMP) 138KV TIE L	138.00	138.00	1	0.04	0	1	2-795 ACSS
756	TL431 LYNX	16TH STREET (TNMP) 138KV TI	138.00	138.00	1	0.04	0	1	2-795 ACSS
757	TL435 MCELROY	SAGE	69.00	138.00	1	1.79	0	1	795 ACSS/AW
758	TL436 HEARTLAND 138KV EXTEN	16TH STREET (TNMP) 138KV TI	69.00	138.00	1	0.70	0	1	959 ACSR/TW
759	TL438 BURMA	STERLING CITY	69.00	138.00	1	1.36	0	1	795 ACSS
760	TL441 Pig Creek	Flat Top (TNMP)	138.00	138.00	1	0.05	0	1	795 ACSS
761	TL442 Bond Road Extension (operating at 69kV)	Flat Top (TNMP)	69.00	138.00	1	0.05	0	1	959.6 ACSS
762	TL443 Hubbard Booster #1	Salt Prong	69.00	138.00	1	0.06	0	1	795 ACSR
763	TL447 BELKNAP 138KV EXTENSI	Flat Top (TNMP)	69.00	138.00	1	0.12	0	1	T2-477 ACSR
764	TL450 Pig Creek	Taygete II 138V Tie Line	138.00	138.00	1	0.05	0	1	795 ACSS
765	TL454 ESKOTA	ROBY 138KV LINE	69.00	138.00	1	2.85	0	1	T2-477 ACSR
766	TL460 SARAGOSA	SOLSTICE (NORTH)	138.00	138.00	1	0.05	0	1	795 ACSS
767	TL461 Tinsley Extension		138.00	138.00	1	0.01	0	1	795 ACSS
768	TL466 IBIS	SALT PRONG	69.00	138.00	1	0.06	0	1	795 ACSR
769	TL468 THROCKMORTON	MUNDAY	69.00	138.00	1	36.17	0	1	795 ACSS
770	TL470 RULE	ASPERMONT	69.00	138.00	1	0.12	0	1	336.0 ACSR
771	TL471 RULE	POINTER	69.00	138.00	1	0.06	0	1	336 ACSR
772	TL473 Rio Pecos	Soaptree (TNMP)	138.00	138.00	1	0.04	0	1	2-795 ACSS
773	TL474 Cross Plains	Putnam 138kV Line (operating at 69kV)	69.00	138.00	1	0.10	0	1	795 ACSS
774	TL479 ANSON	RADIUM	69.00	138.00	1	8.30	0	1	T2-477 ACSR
775	TL481 Maddux	Ratliff	138.00	138.00	1	0.06	0	1	795 ACSS
776	TL482 Aspermont	Hamlin 138kV Line (operating at 69kV)	69.00	138.00	1	0.17	0	1	2/0 ACSR
777	TL483 Jayton	Aspermont 138kV Line (operating at 69kV)	69.00	138.00	1	0.16	0	1	336.4 ACSR
778	TL484 Aspermont	Aspermont (BEPC) 138kV Line (operating at 69kV)	69.00	138.00	1	0.04	0	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)
779	TL490 Avenger	Atwell (TEC) 69kV Extension	69.00	138.00	1	0.02	0	1	795 ACSS
780	TL492 Creosote	Coyanosa (TNMP) Ext. North	138.00	138.00	1	0.04	0	1	2-795 ACSS
781	TL493 Creosote	Coyanosa (TNMP) Ext. South	138.00	138.00	1	0.05	0	1	2-795 ACSS
782	TL495 Fort Stockton Switch	Fort Stockton Switch (LCRA)	138.00	138.00	2	0.04	0	1	795 ACSS
783	TL500 Palouse	Appaloosa Run	138.00	138.00	1	0.02	0	1	795 ACSS
784	TL512 BRONCO	HOUSE MOUNTAIN	69.00	138.00	1	0.10	0	1	795 ACSS
785	TL519 ABILENE NORTHWEST	LANCIUM	138.00	138.00	1	0.02	0	1	795 ACSR
786	TL519 ABILENE NORTHWEST	LANCIUM	138.00	138.00	4	0.05	0	1	2500 XLPE
787	TL526 Bluff Creek	Horse Hollow	138.00	138.00	1	0.28	0	1	954 ACSR
788	TL5301 Asherton	Escondido (LCRA)	138.00	138.00	1	0.02	0	1	795 ACSR
789	TL5311 REVILLA	VENADO TIE LINE	138.00	138.00	1	0.13	0	1	795 ACSS
790	69kV for AEPTN		69.00	69.00	—	1,464.97	0		VARIOUS
791	Line costs and expense are	not available by individual							
792	transmission line.	Totals shown in col j-p							
36	TOTAL					8,493	50	798	

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			
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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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792	246,581,399	3,267,721,102	3,514,302,501	342,886	13,457,682		13,800,568
36	246,581,399	3,267,721,102	3,514,302,501	342,886	13,457,682	0	13,800,568

Name of Respondent: AEP Texas	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	TL520 SALVARE	IRIS	0.03	1	1	1	1	795	ACSR		345.00
2	TL5189 CHAMPLIN	VALERO EAST	1.42	1	1	1	1	795	ACSS		69.00
3	TL5214 POESTA	THREE RIVERS	28.83	1	1	1	1	795	ACSS		138.00
4	TL5219 POESTA EXTENSION		0.60	1	1	1	1	795	ACSS		69.00
5	TL5261 BRACKETTVILLE	ESCONDIDO	45.40	1	1	1	1	795	ACSS		69.00
6	TL5270 NAVAL BASE	NORTH PADRE TAP	5.15	1	1	1	1	795	ACSS		69.00
7	TL5297 EDROY	MATHIS	13.87	1	1	1	1	795	ACSS		69.00
8	TL5363 CHARTER	BRIGHTSIDE	0.74	1	1	1	1	795	ACSS		138.00
9	TL5368 ROMA TAP	STARR	0.05	1	1	1	1	795	ACSS		138.00
10	TL5385 CLARKWOOD	CARINA BESS	0.02	1	1	1	1	795	ACSS		138.00
11	TL5412 FRONTERA SW	Frontera Energy Center #1	0.04	1	1	1	1	1272	ACSR		138.00
12	TL5413 FRONTERA SW	Frontera Energy Center #2	0.03	1	1	1	1	1272	ACSR		138.00
13	TL5414 FRONTERA SW	Frontera Energy Center #3	0.05	1	1	1	1	1272	ACSR		138.00
14	TL7101 SANTO NINO	WORMSER Switching Station	0	1	1	1	1	795	ACSS		138.00
15	TL408 SONORA	ELDORADO LIVE OAK	2.40	1	1	1	1	795	ACSS		69.00
16	TL438 BURMA	STERLING CITY	1.36	1	1	1	1	795	ACSS		69.00
17	TL468 THROCKMORTON	MUNDAY	36	1	1	1	1	795	ACSS		69.00
18	TL471 RULE	POINTER	0	1	1	1	1	336	ACSS		69.00
19	TL512 BRONCO	HOUSE MOUNTAIN	0	1	1	1	1	795	ACSS		69.00
20	TL519 ABILENE NORTHWEST	LANCIUM	0	1	1	1	1	795	ACSS		138.00
21	TL519 ABILENE NORTHWEST	LANCIUM	0	4	1	1	1	2500	XLPE		138.00
44	TOTAL		137		21	21	21				

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		1,211,043			1,211,043	
2	626,345	4,075,140	468,944		5,170,429	
3	5,860,377	26,656,437	6,256,014		38,772,828	
4		2,017,517	349,950		2,367,467	
5	19,774,543	41,743,190	1,993,393		63,511,126	
6		20,546,456	2,214,366		22,760,822	
7		11,796,627	3,222,488		15,019,115	
8	5,891	210,195	235,192		451,278	
9		166,916	79,283		246,199	
10		307,487	118,129		425,616	
11		503			503	
12		503			503	
13		503			503	
14	20,443	816,206	543,620		1,380,269	
15		4,698,760	654,004		5,352,764	
16		1,986,869	388,561		2,375,430	
17	2,077,426	14,630,942	5,102,943		21,811,311	
18		332,224	120,583		452,807	
19		600,772	92,869		693,641	
20						
21		1,243	3,286		4,529	
44	28,365,025	131,799,533	21,843,625		182,008,183	

Name of Respondent: AEP Texas	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	AIRLINE(CP) - TX	Distribution		138.00	0.00	0.00	0.00	0	0
2	AIRLINE(CP) - TX	Distribution		69.00	0.00	0.00	0.00	0	0
3	AIRLINE(CP) - TX	Distribution		69.00	0.00	0.00	0.00	0	0
4	ALAZAN - TX	Distribution		138.00	24.90	0.00	10.50	1	0
5	ALAZAN - TX	Transmission		26.00	12.47	0.00	9.25	1	0
6	ALICE - TX	Transmission		138.00	69.00	12.00	93.00	1	0
7	ALICE - TX	Transmission		69.00	12.47	0.00	28.00	1	0
8	AMISTAD - TX	Transmission		138.00	12.47	0.00	5.60	1	0
9	ANNA STREET - TX	Distribution		138.00	12.47	0.00	80.00	2	0
10	ARANSAS PASS - TX	Distribution		69.00	0.00	0.00	0.00	0	0
11	ARANSAS PASS - TX	Distribution		138.00	69.00	12.00	224.00	1	0
12	ARANSAS PASS - TX	Distribution		69.00	0.00	0.00	0.00	0	0
13	ARCADIA - TX	Distribution		12.00	0.00	0.00	0.00	0	0
14	ARCADIA - TX	Distribution		138.00	12.47	0.00	89.60	2	0
15	ARMSTRONG - TX	Distribution		138.00	12.47	0.00	5.60	1	0
16	ASHERTON - TX	Distribution		69.00	0.00	0.00	0.00	0	0
17	ASHERTON - TX	Distribution		138.00	69.00	13.09	130.00	1	0
18	ASHERTON - TX	Distribution		138.00	0.00	0.00	0.00	0	0
19	B&B GRAVEL - TX	Distribution		69.00	12.47	0.00	4.80	3	0
20	BANQUETE - TX	Distribution		69.00	12.47	0.00	9.40	1	0
21	BAY CITY - TX	Distribution		138.00	12.47	0.00	89.60	2	0
22	BAY CITY - TX	Distribution		138.00	0.00	0.00	0.00	0	0
23	BEEVILLE - TX	Distribution		69.00	12.00	0.00	28.00	1	0
24	BEEVILLE - TX	Distribution		69.00	0.00	0.00	0.00	0	0
25	BEEVILLE - TX	Distribution		69.00	12.47	0.00	28.00	1	0
26	BERCLAIR - TX	Distribution		69.00	7.50	0.00	3.00	3	0
27	BESSEL - TX	Distribution		138.00	0.00	0.00	0.00	0	0
28	BIG FOOT SW - TX	Distribution		69.00	0.00	0.00	0.00	0	0
29	BIG FOOT SW - TX	Distribution		138.00	0.00	0.00	0.00	0	0
30	BIG FOOT SW - TX	Transmission		138.00	70.50	12.47	54.00	1	0
31	BIG OAK - TX	Transmission		23.00	12.00	0.00	1.00	1	0
32	BIG OAK - TX	Transmission		69.00	13.09	0.00	25.00	1	0
33	BIG WELLS - TX	Transmission		138.00	12.47	0.00	10.50	1	0
34	BISHOP - TX	Transmission		69.00	12.47	0.00	9.40	1	0
35	BLACK BAYOU - TX	Transmission		138.00	12.47	0.00	10.50	1	0
36	BLESSING - TX	Distribution		69.00	12.00	0.00	4.50	3	0
37	BLESSING - TX	Distribution		138.00	69.00	12.47	83.00	1	0
38	BLESSING - TX	Distribution		345.00	138.00	12.47	600.00	1	0
39	BONNIE VIEW - TX	Transmission		69.00	13.09	0.00	9.38	1	0
40	BRACKETTVILLE - TX	Transmission		138.00	13.09	0.00	10.00	1	0
41	BROOKHOLLOW - TX	Transmission		138.00	69.00	13.20	41.67	1	0
42	BROOKHOLLOW - TX	Transmission		69.00	13.09	0.00	25.00	1	0
43	BROOKHOLLOW - TX	Transmission		69.00	12.47	0.00	10.50	1	0
44	BROWNSVILLE (CP) - TX	Transmission		69.00	12.47	0.00	21.00	2	0
45	BRUNI - TX	Transmission		138.00	13.09	0.00	12.50	1	0
46	BUENA VISTA - TX	Distribution		138.00	12.47	0.00	28.00	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)
47	CABANISS - TX	Distribution		138.00	12.00	0.00	30.00	1	0
48	CAMPWOOD - TX	Distribution		69.00	7.20	0.00	5.01	3	0
49	CAMPWOOD - TX	Distribution		69.00	0.00	0.00	0.00	0	0
50	CAMPWOOD - TX	Distribution		26.00	12.47	7.20	3.00	1	0
51	CAMPWOOD - TX	Distribution		26.00	12.47	0.00	3.00	1	0
52	CARANCAHUA - TX	Transmission		69.00	12.00	0.00	10.50	1	0
53	CARBIDE - TX	Transmission		138.00	69.00	12.47	280.00	2	0
54	CASA BLANCA - TX	Transmission		69.00	13.09	0.00	9.40	1	0
55	CATARINA - TX	Transmission		138.00	12.00	0.00	25.00	1	0
56	CHARLOTTE - TX	Distribution		69.00	13.09	0.00	9.38	1	0
57	CHASE FIELD - TX	Distribution		69.00	13.09	0.00	7.50	1	0
58	CHASE FIELD - TX	Transmission		69.00	12.47	0.00	9.40	1	0
59	CHOKE CANYON - TX	Transmission		138.00	13.09	0.00	15.00	1	0
60	CITRUS CITY - TX	Transmission		138.00	13.09	0.00	50.00	2	0
61	CLARKWOOD - TX	Distribution		12.00	0.00	0.00	0.00	0	0
62	CLARKWOOD - TX	Distribution		138.00	12.47	0.00	56.00	2	0
63	COFFEE PORT - TX	Transmission		138.00	0.00	0.00	0.00	0	0
64	COFFEE PORT - TX	Transmission		138.00	12.47	0.00	10.50	1	0
65	COLETO CREEK - TX	Distribution		345.00	138.00	13.80	600.00	1	0
66	COLETO CREEK - TX	Distribution		345.00	138.00	12.47	600.00	1	0
67	COLETO CREEK - TX	Distribution		13.80	0.00	0.00	0.00	0	0
68	COMSTOCK - TX	Transmission		138.00	13.00	0.00	7.50	1	0
69	CONOCO - TX	Transmission		138.00	12.47	0.00	6.25	1	0
70	CONTINENTAL(CP) - TX	Transmission		69.00	69.00	13.00	25.00	1	0
71	COTULLA - TX	Distribution		138.00	12.00	0.00	50.00	2	0
72	CRESTONIO - TX	Distribution		138.00	12.47	0.00	19.90	2	0
73	DEL MAR - TX	Distribution		138.00	12.00	0.00	40.00	1	0
74	DEL MAR - TX	Distribution		138.00	0.00	0.00	0.00	0	0
75	DEL MAR - TX	Distribution		138.00	0.00	0.00	0.00	0	0
76	DEL RIO - TX	Distribution		138.00	12.47	0.00	33.60	2	0
77	DEVINE - TX	Distribution		69.00	13.09	0.00	19.40	2	0
78	DEVINE - TX	Distribution		69.00	12.47	0.00	18.75	3	0
79	DEVINE - TX	Distribution		69.00	12.00	0.00	19.40	2	0
80	DILLEY - TX	Distribution		69.00	13.09	0.00	18.75	2	0
81	DILLEY SW - TX	Distribution		138.00	69.00	12.47	37.00	1	0
82	DILLEY SW - TX	Transmission		138.00	0.00	0.00	0.00	0	0
83	DILLEY SW - TX	Transmission		69.00	0.00	0.00	0.00	0	0
84	DILLEY SW - TX	Transmission		69.00	0.00	0.00	0.00	0	0
85	DIMMIT - TX	Distribution		138.00	13.09	0.00	25.00	1	0
86	DUSTDEVIL - TX	Distribution		138.00	12.00	13.80	70.00	2	0
87	DUSTDEVIL - TX	Distribution		138.00	35.40	13.80	70.00	2	0
88	DUSTDEVIL - TX	Distribution		138.00	12.00	0.00	70.00	2	0
89	DUSTDEVIL - TX	Distribution		138.00	35.40	0.00	70.00	2	0
90	EAGLE LAKE - TX	Transmission		12.00	0.00	0.00	0.00	0	0
91	EAGLE LAKE - TX	Transmission		69.00	12.47	0.00	19.90	2	0
92	EAGLE PASS - TX	Transmission		138.00	0.00	0.00	0.00	0	0

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93	EAGLE PASS - TX	Transmission		138.00	0.00	0.00	0.00	0	0
94	EAGLE PASS - TX	Distribution		138.00	12.47	0.00	28.00	1	0
95	EAST HARRISON - TX	Distribution		69.00	12.47	0.00	100.80	3	0
96	EDNA - TX	Distribution		138.00	12.47	0.00	18.80	2	0
97	EDROY - TX	Distribution		69.00	0.00	0.00	0.00	0	0
98	EL CAMPO - TX	Distribution		138.00	69.00	12.47	93.00	1	0
99	EL CAMPO - TX	Distribution		69.00	12.47	0.00	28.00	1	0
100	EL CAMPO - TX	Distribution		12.00	0.00	0.00	0.00	0	0
101	EL CAMPO - TX	Distribution		138.00	12.47	0.00	28.00	1	0
102	EL GATO - TX	Distribution		138.00	13.09	0.00	40.00	1	0
103	ELSA - TX	Distribution		138.00	12.47	0.00	56.00	2	0
104	ELSA - TX	Distribution		12.00	0.00	0.00	0.00	0	0
105	ENCINAL - TX	Distribution		138.00	12.47	0.00	5.00	1	0
106	ESCONDIDO - TX	Transmission		138.00	0.00	0.00	0.00	0	0
107	ESCONDIDO - TX	Distribution		138.00	12.47	0.00	25.00	1	0
108	ESPERANZA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
109	ESPERANZA - TX	Transmission		138.00	0.00	0.00	0.00	0	0
110	EULER 138KV - TX	Distribution		138.00	25.00	0.00	25.00	1	0
111	FALCON SW - TX	Distribution		138.00	0.00	0.00	0.00	0	0
112	FALFURRIAS - TX	Distribution		138.00	69.00	13.09	54.00	1	0
113	FALFURRIAS - TX	Distribution		138.00	12.00	0.00	50.00	1	0
114	FOSTER FIELD - TX	Transmission		69.00	12.47	0.00	9.40	1	0
115	FREER - TX	Distribution		69.00	13.09	0.00	9.38	1	0
116	FREER - TX	Transmission		69.00	12.47	0.00	9.40	1	0
117	FRONTERA SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
118	FRONTERA SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
119	FRONTERA SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
120	FULTON (CP) - TX	Distribution		69.00	12.47	0.00	16.80	1	0
121	GANADO - TX	Distribution		138.00	12.47	0.00	9.40	1	0
122	GARCENO - TX	Transmission		138.00	12.47	0.00	25.00	1	0
123	GARWOOD CITY - TX	Transmission		69.00	12.47	0.00	4.50	3	0
124	GARWOOD IDEAL - TX	Transmission		69.00	4.16	0.00	3.00	3	0
125	GARWOOD RELIFT - TX	Distribution		69.00	2.30	0.00	90.00	3	0
126	GARZA - TX	Distribution		69.00	0.00	0.00	0.00	0	0
127	GARZA - TX	Distribution		138.00	70.50	13.09	90.00	1	0
128	GATEWAY (CP) - TX	Distribution		138.00	12.47	0.00	40.80	2	0
129	GEORGE WEST - TX	Distribution		138.00	12.47	0.00	9.40	1	0
130	GOHLKE - TX	Distribution		138.00	12.47	0.00	6.25	1	0
131	GOLIAD - TX	Distribution		69.00	12.47	0.00	9.38	1	0
132	GOODWIN - TX	Distribution		138.00	13.09	0.00	25.00	1	0
133	GOODWIN - TX	Distribution		138.00	12.47	0.00	25.00	1	0
134	GOVERNMENT WELLS - TX	Distribution		24.94	0.00	0.00	0.00	0	0
135	GOVERNMENT WELLS - TX	Distribution		69.00	24.90	0.00	10.50	1	0
136	GOVERNMENT WELLS - TX	Transmission		26.00	12.47	0.00	5.00	1	0
137	GOVERNMENT WELLS - TX	Transmission		69.00	12.47	0.00	10.50	1	0
138	GOVERNMENT WELLS - TX	Transmission		12.00	0.00	0.00	0.00	0	0

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139	GREENLAKE - TX	Transmission		69.00	13.09	0.00	9.38	1	0
140	GREENLAKE - TX	Distribution		69.00	7.20	0.00	3.34	2	0
141	GREENLAKE - TX	Distribution		69.00	12.47	0.00	1.67	1	0
142	GREGORY - TX	Distribution		69.00	13.09	0.00	50.00	2	0
143	GRETA - TX	Distribution		69.00	12.47	0.00	10.50	1	0
144	HAINE DRIVE - TX	Distribution		138.00	12.47	0.00	56.00	2	0
145	HALL ACRES ROAD - TX	Distribution		138.00	12.47	0.00	44.80	1	0
146	HALL ACRES ROAD - TX	Transmission		138.00	12.47	0.00	46.70	1	0
147	HARLINGEN NO. 1 - TX	Transmission		69.00	12.47	0.00	56.00	2	0
148	HARLINGEN SW ST - TX	Transmission		138.00	69.00	13.09	130.00	1	0
149	HARLINGEN SW ST - TX	Distribution		69.00	13.09	0.00	50.00	2	0
150	HEARD - TX	Distribution		69.00	2.40	0.00	4.50	3	0
151	HEARN ROAD - TX	Distribution		69.00	7.20	0.00	18.75	3	0
152	HEARN ROAD - TX	Distribution		69.00	12.47	0.00	28.00	1	0
153	HIGHWAY 9 - TX	Distribution		69.00	12.47	0.00	100.80	3	0
154	HIGHWAY 9 - TX	Transmission		138.00	70.50	12.47	200.00	1	0
155	HOCHHEIM - TX	Transmission		69.00	2.40	0.00	2.49	3	0
156	HOLLY - TX	Transmission		138.00	12.47	0.00	44.80	1	0
157	HOMEPORT - TX	Transmission		138.00	12.47	0.00	28.00	1	0
158	INDUSTRIAL - TX	Distribution		69.00	12.47	0.00	28.00	1	0
159	INGLESIDE CITY - TX	Distribution		138.00	12.47	0.00	56.00	2	0
160	JOURDANTON - TX	Distribution		12.00	0.00	0.00	0.00	0	0
161	JOURDANTON - TX	Distribution		69.00	0.00	0.00	0.00	0	0
162	KARNES CITY - TX	Transmission		138.00	13.09	0.00	25.00	1	0
163	KENEDY - TX	Transmission		69.00	12.47	0.00	10.50	1	0
164	KENEDY SWITCH - TX	Transmission		138.00	69.00	12.00	130.00	1	0
165	KINGSVILLE - TX	Transmission		138.00	12.47	0.00	56.00	2	0
166	KLEBERG - TX	Transmission		138.00	12.47	0.00	56.00	2	0
167	KLEBERG - TX	Transmission		138.00	0.00	0.00	0.00	0	0
168	KNIPPA - TX	Distribution		69.00	7.20	0.00	5.00	3	0
169	KOCH UP RIVER - TX	Distribution		138.00	69.00	12.47	93.00	1	0
170	LA PALMA 138KV - TX	Distribution		138.00	0.00	0.00	0.00	0	0
171	LA PALMA 138KV - TX	Transmission		138.00	0.00	0.00	0.00	0	0
172	LA PALMA 138KV - TX	Distribution		138.00	0.00	0.00	0.00	0	0
173	LA PALMA 345KV - TX	Distribution		345.00	138.00	13.80	672.00	1	0
174	LA PALMA 69 KV - TX	Distribution		138.00	69.00	12.00	297.00	2	0
175	LA PALMA STATCOM - TX	Distribution		23.00	0.00	0.00	0.00	0	0
176	LAKESIDE (CP) - TX	Distribution		69.00	2.30	0.00	4.50	3	0
177	LANE CITY - TX	Distribution		138.00	0.00	0.00	0.00	0	0
178	LANE CITY PUMP - TX	Distribution		138.00	4.16	0.00	5.00	1	0
179	LAREDO HEIGHTS - TX	Transmission		138.00	12.47	0.00	80.00	2	0
180	LAREDO PLANT - TX	Transmission		138.00	12.47	0.00	28.00	1	0
181	LAREDO PLANT - TX	Distribution		138.00	70.50	13.09	54.00	1	0
182	LAREDO PLANT - TX	Distribution		138.00	69.00	13.09	54.00	1	0
183	LAREDO STATCOM - TX	Distribution		34.50	14.04	0.00	226.80	6	0
184	LEARY LANE - TX	Distribution		69.00	12.47	0.00	89.60	2	0

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185	LIVE OAK - TX	Distribution		69.00	12.47	0.00	28.00	1	0
186	LOLITA - TX	Distribution		138.00	12.47	0.00	10.50	1	0
187	LON HILL - TX	Distribution		138.00	70.50	12.47	200.00	1	0
188	LON HILL - TX	Distribution		7.62	0.00	0.00	0.00	0	0
189	LON HILL - TX	Distribution		138.00	69.00	12.47	1600.00	8	0
190	LON HILL - TX	Distribution		345.00	138.00	12.00	1350.00	2	0
191	LON HILL - TX	Distribution		138.00	0.00	0.00	0.00	0	0
192	LON HILL - TX	Distribution		13.80	0.00	0.00	0.00	0	0
193	LONE STAR - TX	Distribution		69.00	12.47	0.00	2.49	3	0
194	LONE TREE - TX	Distribution		69.00	12.47	0.00	1.00	1	0
195	LONE TREE - TX	Distribution		69.00	0.00	0.00	0.00	0	0
196	LOS FRESNOS - TX	Distribution		138.00	12.47	0.00	50.00	2	0
197	LYTLE - TX	Distribution		69.00	7.20	0.00	4.50	3	0
198	MAGILL 138KV - TX	Distribution		138.00	0.00	0.00	0.00	0	0
199	MAGNOLIA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
200	MAGNOLIA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
201	MAGNOLIA - TX	Distribution		138.00	13.09	0.00	12.50	1	0
202	MAGRUDER - TX	Transmission		69.00	12.47	0.00	56.00	2	0
203	MALONE - TX	Transmission		69.00	12.47	0.00	4.50	3	0
204	MALONE - TX	Transmission		12.00	0.00	0.00	0.00	0	0
205	MARKHAM - TX	Distribution		69.00	12.47	0.00	6.00	1	0
206	MATHIS - TX	Distribution		69.00	12.47	0.00	19.90	2	0
207	MATHIS - TX	Distribution		12.00	0.00	0.00	0.00	0	0
208	MATTHEWS - TX	Distribution		69.00	12.47	0.00	5.01	3	0
209	MAVERICK - TX	Transmission		138.00	12.47	0.00	5.00	1	0
210	MAYBERRY - TX	Transmission		138.00	13.09	0.00	40.00	1	0
211	MAYBERRY - TX	Distribution		138.00	13.09	0.00	24.00	1	0
212	MAYO - TX	Distribution		138.00	13.09	0.00	25.00	1	0
213	MCCOLL ROAD - TX	Distribution		138.00	12.47	0.00	40.00	1	0
214	MCKENZIE ROAD - TX	Distribution		138.00	12.47	0.00	28.00	1	0
215	MEDIO CREEK - TX	Distribution		138.00	12.47	0.00	10.50	1	0
216	MESQUITE - TX	Distribution		12.47	24.90	2.51	5.00	1	0
217	MILITARY HIGHWAY - TX	Distribution		34.50	14.04	0.00	151.27	4	0
218	MILITARY HIGHWAY - TX	Distribution		138.00	0.00	0.00	0.00	0	0
219	MILITARY HIGHWAY - TX	Distribution		138.00	0.00	0.00	0.00	0	0
220	MILO - TX	Distribution		138.00	12.47	0.00	28.00	1	0
221	MINES ROAD - TX	Distribution		138.00	138.00	13.80	30.00	2	0
222	MINES ROAD - TX	Distribution		138.00	12.47	0.00	28.00	1	0
223	MINES ROAD - TX	Distribution		138.00	13.09	13.80	30.00	2	0
224	MOCKINGBIRD - TX	Transmission		138.00	13.09	0.00	25.00	1	0
225	MOLINA - TX	Transmission		138.00	0.00	0.00	0.00	0	0
226	MOLINA - TX	Transmission		138.00	0.00	0.00	0.00	0	0
227	MOORE FIELD - TX	Transmission		23.00	12.47	2.40	10.50	1	0
228	MOORE FIELD - TX	Transmission		26.00	12.47	0.00	10.50	1	0
229	MOORE FIELD - TX	Distribution		138.00	12.47	0.00	25.00	2	0
230	MORRIS STREET - TX	Transmission		138.00	0.00	0.00	0.00	0	0

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		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
231	MORRIS STREET - TX	Distribution		138.00	12.47	0.00	134.40	3	0
232	MUSTANG ISLAND - TX	Distribution		69.00	13.09	0.00	9.38	1	0
233	NAVAL BASE - TX	Transmission		138.00	70.50	12.47	120.00	1	0
234	NELSON SHARPE III - TX	Transmission		345.00	138.00	13.80	675.00	1	0
235	NELSON SHARPE III - TX	Transmission		138.00	0.00	0.00	0.00	0	0
236	NELSON SHARPE III - TX	Distribution		138.00	138.00	0.00	150.00	1	0
237	NIXON - TX	Distribution		138.00	13.09	0.00	45.00	4	0
238	NORDHEIM - TX	Transmission		138.00	13.09	0.00	12.50	1	0
239	NORMANNA CST - TX	Transmission		69.00	12.47	0.00	2.49	3	0
240	NORTH ALAMO - TX	Transmission		138.00	13.09	0.00	25.00	1	0
241	NORTH ALAMO - TX	Transmission		138.00	12.47	0.00	22.40	1	0
242	NORTH EDINBURG - TX	Transmission		138.00	69.00	12.00	83.00	1	0
243	NORTH EDINBURG - TX	Transmission		345.00	138.00	12.00	1200.00	2	0
244	NORTH EDINBURG - TX	Distribution		138.00	69.00	13.20	72.80	1	0
245	NORTH EDINBURG - TX	Distribution		138.00	0.00	0.00	0.00	0	0
246	NORTH EDINBURG - TX	Distribution		69.00	13.09	0.00	25.00	1	0
247	NORTH EDINBURG - TX	Distribution		138.00	0.00	0.00	0.00	0	0
248	NORTH EDINBURG - TX	Distribution		69.00	12.47	0.00	28.00	1	0
249	NORTH EDINBURG - TX	Distribution		345.00	0.00	0.00	0.00	0	0
250	NORTH EDINBURG - TX	Distribution		345.00	0.00	0.00	0.00	0	0
251	NORTH EDINBURG - TX	Distribution		13.20	0.00	0.00	0.00	0	0
252	NORTH ELLA - TX	Distribution		69.00	2.30	0.00	3.00	3	0
253	NORTH MCALLEN - TX	Distribution		138.00	12.47	0.00	124.80	3	0
254	NORTH MERCEDES - TX	Distribution		12.00	0.00	0.00	0.00	0	0
255	NORTH MERCEDES - TX	Distribution		138.00	13.09	0.00	50.00	2	0
256	NORTH PADRE ISLE. 69 - TX	Distribution		138.00	0.00	0.00	0.00	0	0
257	NORTH PADRE ISLE. 69 - TX	Distribution		69.00	13.00	0.00	28.00	1	0
258	NORTH PADRE ISLE. 69 - TX	Distribution		69.00	12.47	0.00	28.00	1	0
259	NORTH VICTORIA - TX	Transmission		69.00	12.47	0.00	89.60	2	0
260	NORTH WESLACO - TX	Transmission		12.00	0.00	0.00	0.00	0	0
261	OCONNER - TX	Distribution		69.00	12.47	0.00	2.50	1	0
262	ODEM - TX	Distribution		69.00	12.47	0.00	10.50	1	0
263	ODEM - TX	Distribution		69.00	12.00	0.00	10.50	1	0
264	OLEANDER - TX	Distribution		138.00	70.50	12.47	130.00	1	0
265	OLMITO - TX	Transmission		138.00	12.47	0.00	25.00	1	0
266	PALACIOS - TX	Transmission		69.00	12.47	0.00	10.50	1	0
267	PALMHURST - TX	Transmission		138.00	12.47	0.00	86.50	2	0
268	PALMHURST - TX	Distribution		12.00	0.00	0.00	0.00	0	0
269	PALMVIEW - TX	Distribution		138.00	12.47	0.00	68.00	2	0
270	PARKER - TX	Distribution		69.00	12.47	0.00	4.50	3	0
271	PEARSALL - TX	Distribution		69.00	12.47	0.00	18.80	2	0
272	PETTUS - TX	Distribution		69.00	13.09	0.00	12.50	1	0
273	PETTUS - TX	Distribution		69.00	24.90	0.00	10.50	1	0
274	PHARAOH - TX	Distribution		138.00	12.47	0.00	15.00	1	0
275	PHARR - TX	Distribution		138.00	12.47	0.00	37.30	1	0
276	PHARR STATCOM - TX	Distribution		23.00	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)
277	PICACHO - TX	Distribution		138.00	0.00	0.00	0.00	0	0
278	PLACEDO - TX	Distribution		69.00	12.47	0.00	6.00	1	0
279	PLEASANTON - TX	Distribution		138.00	70.50	13.09	54.00	1	0
280	PLEASANTON - TX	Transmission		138.00	12.47	0.00	56.00	2	0
281	POESTA - TX	Transmission		138.00	70.50	13.09	78.00	1	0
282	POINT COMFORT - TX	Transmission		69.00	12.47	0.00	3.00	2	0
283	POINT COMFORT - TX	Transmission		69.00	12.00	0.00	1.50	1	0
284	POLK AVENUE - TX	Distribution		138.00	12.47	0.00	91.50	2	0
285	POLK AVENUE - TX	Distribution		12.00	0.00	0.00	0.00	0	0
286	PORT ARANSAS - TX	Distribution		69.00	12.47	0.00	56.00	2	0
287	PORT ISABEL SWITCH - TX	Distribution		12.00	0.00	0.00	0.00	0	0
288	PORT ISABEL SWITCH - TX	Distribution		138.00	13.09	0.00	25.00	1	0
289	PORT ISABEL SWITCH - TX	Transmission		138.00	12.47	0.00	9.40	1	0
290	PORT LAVACA - TX	Transmission		69.00	0.00	0.00	0.00	0	0
291	PORTLAND (CP) - TX	Transmission		138.00	12.47	0.00	28.00	1	0
292	PRAIRIE PUMP - TX	Transmission		69.00	12.47	0.00	4.50	3	0
293	PREMONT - TX	Transmission		69.00	12.47	0.00	21.10	2	0
294	PREMONT - TX	Transmission		13.20	0.00	0.00	0.00	0	0
295	PRIMERA - TX	Transmission		138.00	138.00	138.00	320.00	12	0
296	PRIMERA - TX	Transmission		138.00	13.09	138.00	160.00	6	0
297	PUEBLO - TX	Transmission		138.00	12.47	0.00	30.00	1	0
298	RACHAL - TX	Distribution		138.00	12.47	0.00	12.50	1	0
299	RANDADO - TX	Distribution		138.00	12.47	0.00	12.50	1	0
300	RANGERVILLE - TX	Distribution		69.00	0.00	0.00	0.00	0	0
301	RANGERVILLE - TX	Distribution		69.00	12.47	0.00	8.40	1	0
302	RANGERVILLE - TX	Distribution		69.00	13.09	0.00	9.38	1	0
303	RANGERVILLE - TX	Distribution		23.00	12.47	0.00	7.84	1	0
304	REFUGIO - TX	Distribution		69.00	12.47	0.00	21.00	2	0
305	REFUGIO - TX	Distribution		138.00	70.50	13.09	54.00	1	0
306	REFUGIO - TX	Distribution		12.00	0.00	0.00	0.00	0	0
307	RESACA - TX	Distribution		69.00	0.00	0.00	0.00	0	0
308	RINCON - TX	Distribution		138.00	69.00	13.80	50.40	1	0
309	RIO BRAVO - TX	Distribution		26.00	12.47	0.00	7.00	1	0
310	RIO BRAVO - TX	Distribution		138.00	24.94	0.00	12.50	1	0
311	RIO BRAVO - TX	Distribution		26.00	12.47	0.00	7.00	1	0
312	RIO BRAVO - TX	Transmission		138.00	0.00	0.00	0.00	0	0
313	RIO BRAVO - TX	Distribution		138.00	24.90	0.00	10.50	1	0
314	RIO GRANDE CITY - TX	Distribution		138.00	0.00	0.00	0.00	0	0
315	RIO GRANDE CITY - TX	Distribution		69.00	12.47	0.00	28.00	1	0
316	RIO GRANDE CITY - TX	Distribution		138.00	70.50	12.47	90.00	1	0
317	RIO HONDO SW STA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
318	RIO HONDO SW STA - TX	Distribution		345.00	138.00	13.80	675.00	1	0
319	RIO HONDO SW STA - TX	Distribution		345.00	138.00	13.00	600.00	1	0
320	RIO HONDO SW STA - TX	Distribution		345.00	0.00	0.00	0.00	0	0
321	RIO RICO - TX	Distribution		69.00	12.47	0.00	18.00	2	0
322	RIO RICO - TX	Distribution		69.00	0.00	0.00	0.00	0	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)			
323	RIO RICO - TX	Distribution		12.00	0.00	0.00	0.00	0	0
324	RIVERSIDE (CP) - TX	Transmission		69.00	2.30	0.00	4.50	3	0
325	ROCKPORT (CP) - TX	Distribution		138.00	69.00	13.09	108.00	2	0
326	ROCKSPRINGS ATL - TX	Distribution		69.00	12.47	0.00	2.70	3	0
327	RODD FIELD - TX	Transmission		138.00	12.47	0.00	91.50	2	0
328	ROMA - TX	Transmission		138.00	12.47	0.00	25.00	2	0
329	RUNGE - TX	Distribution		138.00	13.09	0.00	50.00	4	0
330	RUNGE - TX	Distribution		138.00	13.09	0.00	50.00	4	0
331	SABINAL - TX	Distribution		69.00	7.20	0.00	4.67	3	0
332	SAN BENITO - TX	Distribution		69.00	12.00	0.00	50.00	2	0
333	SAN BENITO - TX	Distribution		69.00	13.09	0.00	50.00	2	0
334	SAN BENITO - TX	Transmission		69.00	12.47	0.00	25.00	1	0
335	SAN BENITO - TX	Transmission		69.00	12.00	0.00	50.00	2	0
336	SAN BENITO - TX	Transmission		69.00	13.09	0.00	50.00	2	0
337	SAN DIEGO - TX	Distribution		69.00	13.09	0.00	12.50	1	0
338	SAN DIEGO - TX	Distribution		69.00	12.47	0.00	9.40	1	0
339	SAN YGNACIO - TX	Distribution		138.00	12.47	0.00	6.25	1	0
340	SANTO NINO - TX	Distribution		138.00	0.00	0.00	0.00	0	0
341	SANTO NINO - TX	Distribution		138.00	0.00	0.00	0.00	0	0
342	SEAWALL - TX	Distribution		69.00	12.47	0.00	9.40	1	0
343	SEAWALL - TX	Distribution		69.00	13.09	0.00	12.50	1	0
344	SHARYLAND - TX	Distribution		138.00	12.47	0.00	87.30	2	0
345	SIERRA VISTA - TX	Distribution		138.00	13.09	0.00	25.00	1	0
346	SINTON - TX	Distribution		69.00	12.47	0.00	19.90	2	0
347	SKIDMORE - TX	Distribution		69.00	13.09	0.00	5.75	1	0
348	SMITH - TX	Distribution		69.00	2.30	0.00	4.50	3	0
349	SOUTH MCALLEN - TX	Distribution		138.00	0.00	0.00	0.00	0	0
350	SOUTH MCALLEN - TX	Distribution		138.00	12.47	0.00	50.00	2	0
351	SOUTH MISSION - TX	Distribution		138.00	12.47	0.00	50.00	2	0
352	SOUTH PADRE ISLAND - TX	Distribution		138.00	12.47	0.00	56.00	2	0
353	SOUTH SANTA ROSA - TX	Distribution		138.00	12.47	0.00	50.00	2	0
354	SOUTH SANTA ROSA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
355	SOUTHEAST EDINBURG - TX	Distribution		12.00	0.00	0.00	0.00	0	0
356	SOUTHEAST EDINBURG - TX	Transmission		138.00	12.47	0.00	56.00	2	0
357	SOUTHSIDE - TX	Transmission		138.00	12.47	0.00	84.00	3	0
358	STADIUM - TX	Transmission		69.00	0.00	0.00	0.00	0	0
359	STAFFORD HILL - TX	Transmission		138.00	13.09	0.00	65.00	6	0
360	STAFFORD HILL - TX	Distribution		138.00	12.00	0.00	32.50	3	0
361	STEVENS - TX	Distribution		69.00	4.16	0.00	21.00	2	0
362	STEWART ROAD - TX	Distribution		345.00	138.00	34.50	1350.00	2	0
363	STEWART ROAD - TX	Transmission		138.00	69.00	12.00	33.00	1	0
364	STEWART ROAD - TX	Distribution		138.00	0.00	0.00	0.00	0	0
365	STRATTON (CP) - TX	Distribution		138.00	69.00	12.00	83.30	1	0
366	SUNCHASE - TX	Distribution		138.00	12.47	0.00	28.00	1	0
367	TAFT - TX	Distribution		69.00	12.47	0.00	10.50	1	0
368	TAFT - TX	Distribution		69.00	7.20	0.00	5.01	3	0

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369	TATTON - TX	Distribution		138.00	12.00	0.00	12.50	1	0
370	THREE RIVERS (COR) - TX	Distribution		138.00	70.50	13.09	78.00	1	0
371	THREE RIVERS (COR) - TX	Distribution		69.00	12.47	0.00	18.80	2	0
372	THREE RIVERS (COR) - TX	Distribution		138.00	0.00	0.00	0.00	0	0
373	TYNAN - TX	Transmission		69.00	13.09	0.00	25.00	1	0
374	UNIVERSITY - TX	Transmission		138.00	13.09	0.00	25.00	1	0
375	UNIVERSITY - TX	Transmission		138.00	12.47	0.00	28.00	1	0
376	UVALDE - TX	Distribution		69.00	0.00	0.00	0.00	0	0
377	UVALDE - TX	Distribution		138.00	0.00	0.00	0.00	0	0
378	UVALDE - TX	Distribution		138.00	69.00	13.09	54.00	1	0
379	UVALDE - TX	Distribution		138.00	0.00	0.00	0.00	0	0
380	UVALDE - TX	Transmission		138.00	12.47	0.00	56.00	2	0
381	VALERO EAST - TX	Distribution		138.00	70.50	12.47	120.00	1	0
382	VICTORIA PLANT - TX	Distribution		138.00	69.00	12.47	374.00	2	0
383	VICTORIA PLANT - TX	Transmission		69.00	12.47	0.00	47.88	3	0
384	VICTORIA PLANT - TX	Transmission		69.00	0.00	0.00	0.00	0	0
385	VICTORIA PLANT - TX	Distribution		69.00	12.00	0.00	9.38	1	0
386	VICTORIA PLANT - TX	Distribution		69.00	0.00	0.00	0.00	0	0
387	VILLA CAVAZOS - TX	Distribution		138.00	12.47	0.00	25.00	1	0
388	WADSWORTH - TX	Distribution		138.00	12.47	0.00	10.50	1	0
389	WASHINGTON STREET - TX	Distribution		69.00	12.47	0.00	44.80	1	0
390	WASHINGTON STREET - TX	Distribution		69.00	12.47	0.00	33.60	2	0
391	WEAVER ROAD - TX	Distribution		69.00	12.47	0.00	9.38	1	0
392	WEIL TRACT - TX	Distribution		138.00	12.47	0.00	44.80	1	0
393	WEIL TRACT - TX	Distribution		138.00	0.00	0.00	0.00	0	0
394	WESLACO SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
395	WESLACO SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
396	WESLACO SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
397	WESLACO SWITCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
398	WESLACO UNIT - TX	Distribution		138.00	0.00	0.00	0.00	0	0
399	WESLACO UNIT - TX	Distribution		138.00	12.47	0.00	89.60	2	0
400	WESLACO UNIT - TX	Distribution		138.00	0.00	0.00	0.00	0	0
401	WESLACO UNIT - TX	Distribution		138.00	0.00	0.00	0.00	0	0
402	WESMER - TX	Distribution		138.00	12.47	0.00	56.00	2	0
403	WEST HARLINGEN - TX	Distribution		69.00	12.47	0.00	56.00	2	0
404	WEST MCALLEN - TX	Transmission		138.00	12.47	0.00	89.60	2	0
405	WEST OSO - TX	Transmission		138.00	12.47	0.00	28.00	1	0
406	WESTSIDE SW - TX	Transmission		138.00	0.00	0.00	0.00	0	0
407	WHITEPOINT - TX	Distribution		138.00	69.00	12.00	92.90	1	0
408	WHITEPOINT - TX	Distribution		345.00	138.00	13.80	288.00	1	0
409	WHITEPOINT - TX	Distribution		138.00	0.00	0.00	0.00	0	0
410	WOODSBORO - TX	Distribution		69.00	12.47	0.00	8.40	1	0
411	WOOLDRIDGE - TX	Distribution		138.00	12.47	0.00	28.00	1	0
412	WORMSER ROAD SW - TX	Distribution		138.00	0.00	0.00	0.00	0	0
413	WORMSER ROAD SW - TX	Distribution		138.00	0.00	0.00	0.00	0	0
414	WORMSER ROAD SW - TX	Distribution		138.00	0.00	0.00	0.00	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
415	YORKTOWN - TX	Transmission		138.00	13.09	0.00	25.00	2	0
416	ZACATE CREEK - TX	Transmission		138.00	12.47	0.00	40.00	1	0
417	ZAPATA - TX	Transmission		138.00	13.09	0.00	25.00	2	0
418	ZAPATA - TX	Distribution		138.00	12.47	0.00	25.00	1	0
419	ABILENE AILEEN - TX	Distribution		138.00	13.09	0.50	15.00	1	0
420	ABILENE COUNTRY CLUB - TX	Distribution		138.00	13.09	0.00	20.00	1	0
421	ABILENE EAST - TX	Transmission		138.00	69.00	7.67	84.00	1	0
422	ABILENE EAST - TX	Transmission		138.00	69.30	13.20	62.50	1	0
423	ABILENE EAST - TX	Transmission		138.00	13.09	0.00	28.00	1	0
424	ABILENE INDUSTRIAL PARK - TX	Transmission		138.00	13.09	7.56	56.00	2	0
425	ABILENE NORTHWEST - TX	Distribution		138.00	69.50	36.20	90.00	1	0
426	ABILENE NORTHWEST - TX	Distribution		138.00	0.00	0.00	0.00	0	0
427	ABILENE NORTHWEST - TX	Distribution		138.00	69.00	11.20	91.60	1	0
428	ABILENE OIL MILL - TX	Transmission		69.00	13.00	0.00	25.00	1	0
429	ABILENE ONYX REA - TX	Transmission		69.00	13.00	2.40	12.00	3	0
430	ABILENE POWER PLANT - TX	Transmission		69.00	13.09	0.00	25.00	1	0
431	ABILENE POWER PLANT - TX	Transmission		69.00	7.56	2.40	20.01	3	0
432	ABILENE SOUTH - TX	Transmission		138.00	0.00	0.00	0.00	0	0
433	ABILENE SOUTH - TX	Transmission		138.00	70.50	13.09	318.00	5	0
434	ABILENE SOUTH - TX	Transmission		138.00	69.00	13.09	228.00	4	0
435	AFTON (WT) - TX	Transmission		69.00	7.20	0.00	3.00	3	0
436	ALBANY (WT) - TX	Transmission		69.00	13.00	0.00	10.00	1	0
437	ALBANY FOUNDRY - TX	Distribution		69.00	13.00	0.00	25.00	1	0
438	ALBANY HUBBARD BOOSTER #1 WCT - TX	Distribution		69.00	2.52	0.00	3.75	3	0
439	ALBANY HUBBARD BOOSTER #2 WCT - TX	Distribution		2.40	0.48	0.00	0.13	2	0
440	ALBANY HUBBARD BOOSTER #2 WCT - TX	Distribution		2.40	0.48	0.00	0.05	1	0
441	ALBANY HUBBARD BOOSTER #2 WCT - TX	Distribution		69.00	2.52	0.00	3.75	3	0
442	ALPINE - TX	Distribution		69.00	13.00	0.00	40.00	4	0
443	ANSON - TX	Distribution		69.00	12.00	0.00	18.75	2	0
444	ANSON - TX	Distribution		69.00	12.00	0.00	18.75	2	0
445	ANSON - TX	Transmission		69.00	13.09	0.00	18.75	2	0
446	ANSON - TX	Transmission		69.00	13.09	0.00	18.75	2	0
447	ANSON REA - TX	Transmission		69.00	13.00	0.00	5.00	1	0
448	ARROTT - TX	Distribution		69.00	12.50	0.00	2.50	3	0
449	ASPERMONT - TX	Distribution		138.00	70.50	36.20	78.00	1	0
450	ASPERMONT - TX	Distribution		69.00	13.00	0.00	9.40	1	0
451	ASPERMONT CONTINENTAL OIL CO. - TX	Distribution		69.00	13.00	0.00	3.75	1	0
452	BAIRD CITY - TX	Distribution		69.00	13.00	0.00	5.00	1	0
453	BALLINGER - TX	Distribution		69.00	0.00	0.00	0.00	0	0
454	BALLINGER - TX	Distribution		138.00	66.00	13.80	62.50	1	0
455	BALLINGER - TX	Distribution		138.00	13.09	0.00	25.00	1	0
456	BARNHART - TX	Distribution		69.00	0.00	0.00	0.00	0	0
457	BARNHART - TX	Transmission		69.00	13.09	0.00	9.38	1	0
458	BARRILLA JUNCTION - TX	Transmission		138.00	69.00	6.57	62.50	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)
459	BARRILLA JUNCTION - TX	Transmission		69.00	12.40	0.00	0.33	1	0
460	BIG LAKE - TX	Transmission		138.00	69.00	5.39	50.00	1	0
461	BIG LAKE - TX	Distribution		12.00	4.10	0.00	2.50	3	0
462	BIG LAKE - TX	Distribution		138.00	69.00	2.40	50.00	1	0
463	BIG LAKE - TX	Transmission		69.00	13.00	0.00	10.00	3	0
464	BIG LAKE - PHILLIPS PUMP - TX	Distribution		69.00	12.50	0.00	2.00	3	0
465	BLUFF CREEK - TX	Distribution		34.50	0.00	0.00	0.00	0	0
466	BLUFF CREEK - TX	Distribution		345.00	138.00	34.50	1350.00	2	0
467	BLUFF CREEK - TX	Distribution		138.00	0.00	0.00	0.00	0	0
468	BLUFF CREEK - TX	Distribution		138.00	0.00	0.00	0.00	0	0
469	BLUFFS - TX	Distribution		138.00	12.47	0.00	25.00	1	0
470	BOBCAT HILLS - TX	Transmission		69.00	12.47	0.00	5.00	1	0
471	BOND ROAD - TX	Transmission		69.00	0.00	0.00	0.00	0	0
472	BOND ROAD - TX	Transmission		69.00	13.09	0.00	9.38	1	0
473	BRADY CITY (MUNICIPAL INTERCON - TX	Distribution		0.00	0.00	0.00	0.00	0	0
474	BRADY CITY (MUNICIPAL INTERCON - TX	Transmission		69.00	13.00	7.62	10.50	1	0
475	BRONTE - TX	Transmission		69.00	0.00	0.00	0.00	0	0
476	BRONTE - TX	Transmission		69.00	12.47	0.00	6.25	1	0
477	BRONTE (AMBASSADOR) - TX	Distribution		69.00	13.00	0.00	1.50	3	0
478	BRONTE ATLANTIC - TX	Distribution		69.00	12.50	0.00	1.50	1	0
479	BRYANT RANCH - TX	Transmission		69.00	12.47	0.00	1.00	3	0
480	BUSH KNOB (THROCKMORTON) - TX	Transmission		69.00	7.56	0.00	7.50	3	0
481	CANYON ROCK - TX	Transmission		138.00	13.09	0.00	26.00	2	0
482	CANYON ROCK - TX	Transmission		138.00	13.09	0.00	26.00	2	0
483	CANYON ROCK - TX	Transmission		138.00	12.00	0.00	26.00	2	0
484	CANYON ROCK - TX	Distribution		138.00	12.00	0.00	26.00	2	0
485	CARVER - TX	Distribution		138.00	70.50	70.50	180.00	2	0
486	CARVER - TX	Distribution		138.00	13.09	70.50	180.00	2	0
487	CARVER - TX	Distribution		138.00	70.50	13.09	180.00	2	0
488	CARVER - TX	Distribution		138.00	13.09	13.09	180.00	2	0
489	CARVER - TX	Distribution		138.00	0.00	0.00	0.00	0	0
490	CASSAVA - TX	Distribution		138.00	70.50	13.09	720.00	8	0
491	CEDAR GAP - TX	Distribution		69.00	13.09	2.40	60.00	4	0
492	CEDAR HILL - TX	Distribution		69.00	0.00	0.00	0.00	0	0
493	CEDAR HILL - TX	Distribution		138.00	70.50	13.09	90.00	1	0
494	CHERRY CREEK (WT) - TX	Distribution		69.00	13.09	69.00	15.00	1	0
495	CHILDRESS (69) - TX	Distribution		69.00	12.47	0.00	12.00	1	0
496	CHILDRESS 20TH ST SUB CHILDRES - TX	Distribution		69.00	13.00	0.00	16.00	1	0
497	CHILDRESS WEST - TX	Transmission		138.00	70.50	13.09	432.00	8	0
498	CHILLICOTHE - TX	Transmission		69.00	13.09	0.00	11.19	3	0
499	CHINATI - TX	Distribution		138.00	0.00	0.00	0.00	0	0
500	CHRISTOVAL - TX	Distribution		69.00	13.00	0.00	6.00	1	0
501	CISCO - TX	Distribution		138.00	13.09	0.00	24.00	2	0
502	CLAIRMONT SUN OIL CO. - TX	Transmission		69.00	7.56	0.00	5.00	4	0

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503	CLYDE - TX	Transmission		69.00	0.00	0.00	0.00	0	0
504	CLYDE - TX	Transmission		69.00	13.00	0.00	25.00	1	0
505	CLYDE MAGNOLIA PUMP PIPELINE - TX	Distribution		69.00	2.50	0.00	6.25	1	0
506	COLEMAN EAST - TX	Distribution		138.00	13.09	0.00	16.80	1	0
507	CONAN - TX	Transmission		69.00	0.00	0.00	0.00	0	0
508	CRANE (TESCO INTER) - TX	Transmission		138.00	0.00	0.00	0.00	0	0
509	CRANE (TESCO INTER) - TX	Transmission		138.00	70.50	13.09	130.00	1	0
510	CRANE COUNTY AIRPORT - TX	Transmission		69.00	4.10	0.00	10.50	1	0
511	CROCKETT HEIGHTS (OZONA) - TX	Transmission		69.00	12.00	0.00	2.00	3	0
512	CROSS PLAINS - TX	Transmission		69.00	13.09	0.00	7.50	1	0
513	CROWELL - TX	Distribution		69.00	13.00	0.00	6.20	1	0
514	CRYO - TX	Distribution		138.00	0.00	0.00	0.00	0	0
515	DISCOVERY CANYON - TX	Distribution		69.00	12.50	0.00	5.00	3	0
516	DISCOVERY CANYON - TX	Distribution		69.00	7.20	0.00	1.60	0	1
517	DUNE FIELD - TX	Distribution		69.00	13.00	0.00	10.00	3	0
518	DYESS AFB #1 - TX	Distribution		69.00	7.56	2.40	5.63	2	0
519	DYESS AFB #1 - TX	Distribution		69.00	13.00	2.40	3.13	1	0
520	DYESS AFB #2 - TX	Distribution		69.00	13.00	0.00	16.00	1	0
521	DYESS AFB #3 - TX	Distribution		69.00	7.56	2.40	18.75	3	0
522	EDEN - TX	Distribution		69.00	13.00	0.00	5.00	3	0
523	EDITH HUMBLE - TX	Distribution		69.00	13.09	0.00	3.13	1	0
524	ELDORADO CITIES SERVICE CO. - TX	Transmission		69.00	12.50	0.00	0.67	1	0
525	ELDORADO CITIES SERVICE CO. - TX	Distribution		69.00	12.00	0.00	1.33	2	0
526	ELDORADO LIVE OAK SUB. - TX	Distribution		138.00	69.00	7.00	50.00	1	0
527	ELDORADO LIVE OAK SUB. - TX	Distribution		138.00	69.00	6.60	62.50	1	0
528	ELDORADO LIVE OAK SUB. - TX	Transmission		0.00	0.00	0.00	0.00	0	0
529	ELDORADO SHELL BAILEY - TX	Transmission		69.00	4.36	0.00	7.50	1	0
530	ELM CREEK - TX	Transmission		138.00	13.09	0.00	20.00	1	0
531	ELM CREEK - TX	Transmission		138.00	13.09	0.00	25.00	1	0
532	ELM CREEK - TX	Transmission		138.00	69.00	8.55	91.70	1	0
533	ELMDALE - TX	Transmission		69.00	13.00	0.00	9.40	1	0
534	EOLA - TX	Distribution		69.00	13.00	0.00	3.75	3	0
535	ESPY WELLS - TX	Transmission		69.00	7.20	0.00	0.20	1	0
536	FLOMOT - TX	Transmission		69.00	13.00	0.00	2.49	3	0
537	FORT DAVIS - TX	Distribution		69.00	0.00	0.00	0.00	0	0
538	FORT DAVIS - TX	Distribution		69.00	12.40	0.00	7.50	3	0
539	FORT GRIFFIN - TX	Transmission		69.00	0.00	0.00	0.00	0	0
540	FORT LANCASTER - TX	Distribution		138.00	69.00	12.47	50.00	1	0
541	FORT MCKAVITT - TX	Transmission		69.00	2.40	0.00	1.50	3	0
542	FORT STOCKTON PLANT - TX	Distribution		138.00	69.00	8.88	62.50	1	0
543	FREDERICKSBURG PHILLIPS - TX	Distribution		69.00	2.40	0.00	1.00	3	0
544	FRIEND RANCH - TX	Distribution		138.00	69.00	13.20	62.50	1	0
545	FRIEND RANCH - TX	Distribution		2.40	0.00	0.00	0.00	0	0
546	FRIEND RANCH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
547	FRIESS RANCH - TX	Distribution		69.00	12.50	0.00	2.50	3	0

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548	FT CHADBOURNE - TX	Distribution		138.00	13.09	0.00	10.50	1	0
549	FT PHANTOM CLEAR FORK PUM - TX	Transmission		69.00	2.40	0.00	12.60	3	0
550	FT PHANTOM EAST PUMP STA - TX	Transmission		69.00	4.30	0.00	2499.00	3	0
551	FT PHANTOM PLANT - TX	Distribution		138.00	0.00	0.00	0.00	0	0
552	GILLESPIE (KNOX CITY REA - TX	Distribution		69.00	12.47	0.00	3.00	3	0
553	GIRARD - TX	Distribution		69.00	2.40	0.00	1.00	3	0
554	GRAYBACK - TX	Transmission		69.00	13.09	0.00	5.01	3	0
555	GRIMES FILTRATION PLAN - TX	Transmission		12.00	4.10	0.00	4.98	3	0
556	HAMLIN - TX	Distribution		69.00	13.00	0.00	5.00	2	0
557	HAMLIN - TX	Distribution		69.00	13.00	0.00	3.33	1	0
558	HAMLIN PLASTERCO CELOTEX THR - TX	Distribution		69.00	13.00	0.00	5.00	1	0
559	HAMLIN REA - TX	Distribution		69.00	12.47	0.00	0.83	1	0
560	HAMLIN REA - TX	Distribution		69.00	12.40	0.00	1.67	2	0
561	HAMLIN SHELL PUMP - TX	Distribution		69.00	7.20	0.00	1.00	3	0
562	HAMLIN SHELL PUMP - TX	Transmission		12.00	2.40	0.00	0.60	3	0
563	HAMLIN TEXAS PIPE LINE - TX	Distribution		69.00	12.40	0.00	11.06	3	0
564	HAMLIN TEXAS PIPE LINE - TX	Distribution		69.00	13.09	0.00	0.83	1	0
565	HARROLD OIL FIELD - TX	Distribution		69.00	13.00	0.00	3.75	1	0
566	HARTFORD STREET - TX	Distribution		69.00	13.00	0.00	28.00	1	0
567	HASKELL - TX	Transmission		69.00	7.56	0.00	10.00	3	0
568	HASKELL TEXAS PIPE LINE - TX	Transmission		69.00	4.10	0.00	7.00	1	0
569	HATCHELL REA - TX	Transmission		69.00	12.47	0.00	0.83	1	0
570	HATCHELL REA - TX	Distribution		69.00	13.00	0.00	1.67	2	0
571	HAWLEY HUMBLE - EXXON - TX	Transmission		69.00	13.20	0.00	5.60	1	0
572	HORNET 69KV - TX	Transmission		69.00	13.09	0.00	7.50	1	0
573	HUMBLE KEMPER EXXON - TX	Distribution		69.00	2.40	0.00	5.00	6	0
574	INDIAN MESA - TX	Distribution		138.00	13.09	0.00	3.33	2	0
575	IRAAN - TX	Distribution		69.00	13.00	0.00	10.00	3	0
576	IRAAN - TX	Distribution		69.00	0.00	0.00	0.00	0	0
577	IRAAN AIR PRODUCTS - TX	Distribution		0.00	0.00	0.00	0.00	0	0
578	IRAAN AIR PRODUCTS - TX	Distribution		69.00	2.40	0.00	15.00	3	0
579	JAYTON - TX	Transmission		69.00	4.10	0.00	2.49	3	0
580	KENNEDY PONDER TAP - TX	Transmission		69.00	12.50	0.00	0.15	1	0
581	KIRKLAND - TX	Distribution		69.00	2.40	0.00	0.75	3	0
582	KNOX CITY - TX	Transmission		69.00	13.09	0.00	2.50	1	0
583	KNOX CITY - TX	Transmission		69.00	13.00	0.00	6.60	2	0
584	LAKE PAULINE (TNC) - TX	Distribution		138.00	70.50	13.09	78.00	1	0
585	LCRA WEST YATES SW STA. - TX	Transmission		138.00	69.00	13.03	50.00	1	0
586	LONGWORTH - TX	Transmission		69.00	12.47	0.00	6.25	1	0
587	LOTEBUSH - TX	Distribution		138.00	0.00	0.00	0.00	0	0
588	LOTEBUSH - TX	Distribution		20.78	0.00	0.00	0.00	0	0
589	MAPLE STREET - TX	Distribution		138.00	13.09	13.20	25.00	1	0
590	MARATHON YATES - TX	Distribution		69.00	4.00	0.00	5.00	1	0
591	MARFA - TX	Transmission		69.00	7.20	0.00	1.67	1	0
592	MARFA - TX	Distribution		69.00	13.00	0.00	3.33	2	0

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593	MARFA ALAMITO CREEK - TX	Distribution		138.00	69.00	5.01	46.70	1	0
594	MARFA ALAMITO CREEK - TX	Distribution		138.00	69.00	13.80	46.70	1	0
595	MARFA ALAMITO CREEK - TX	Distribution		69.00	0.00	0.00	0.00	0	0
596	MASON - TX	Distribution		138.00	70.50	13.09	78.00	1	0
597	MASON PHILLIPS - TX	Distribution		69.00	2.40	0.00	1.50	3	0
598	MCCAMEY - TX	Distribution		12.00	4.10	0.00	2.49	3	0
599	MCCAMEY - TX	Distribution		138.00	12.47	0.00	9.38	1	0
600	MCCAMEY SHELL - TX	Distribution		69.00	4.10	0.00	7.50	1	0
601	MCCAMEY SHELL PUMP - TX	Distribution		12.00	4.10	0.00	0.50	1	0
602	MCCAMEY SHELL PUMP - TX	Distribution		12.00	4.16	0.00	1.00	3	0
603	MCCAMEY SHELL PUMP - TX	Distribution		12.00	2.40	0.00	1.00	2	0
604	MCELROY - TX	Distribution		12.00	0.00	0.00	0.00	0	0
605	MCELROY - TX	Distribution		69.00	13.09	0.00	20.00	1	0
606	MCELROY - TX	Distribution		69.00	0.00	0.00	0.00	0	0
607	MCELROY - TX	Distribution		69.00	7.56	0.00	5.00	1	0
608	MCELROY - TX	Distribution		69.00	7.50	0.00	10.00	2	0
609	MCMURRY - TX	Distribution		69.00	13.00	0.00	45.00	2	0
610	MELVIN - TX	Distribution		69.00	13.09	0.00	9.38	1	0
611	MERKEL - TX	Distribution		69.00	13.00	0.00	8.40	1	0
612	MERKEL - TX	Distribution		69.00	0.00	0.00	0.00	0	0
613	MERTZON - TX	Distribution		69.00	13.09	0.00	5.00	1	0
614	MESA VIEW - TX	Distribution		138.00	13.09	0.00	50.00	1	0
615	MIDWAY LANE - TX	Distribution		69.00	12.50	0.00	10.00	3	0
616	MORAN - TX	Distribution		69.00	13.10	0.00	3.00	3	0
617	MULBERRY CREEK - TX	Distribution		138.00	0.00	0.00	0.00	0	0
618	MULBERRY CREEK - TX	Distribution		345.00	138.00	13.20	530.00	2	0
619	MULBERRY CREEK - TX	Transmission		12.00	0.00	0.00	0.00	0	0
620	MUNDAY (EAST-KNOX) - TX	Distribution		138.00	0.00	0.00	0.00	0	0
621	MUNDAY (EAST-KNOX) - TX	Distribution		138.00	69.00	13.09	54.00	1	0
622	MUNDAY (KNOX) - TX	Distribution		69.00	13.09	0.00	9.40	1	0
623	NORTH BRADY - TX	Distribution		69.00	0.00	0.00	10.00	2	0
624	NORTH BRADY - TX	Distribution		69.00	2.20	0.00	10.00	2	0
625	NORTH MCCAMEY - TX	Distribution		138.00	13.09	0.00	28.00	1	0
626	OKLAUNION 345-TNC - TX	Transmission		138.00	13.09	0.00	8.40	1	0
627	OKLAUNION HVDC INTER - TX	Transmission		345.00	26.40	26.40	270.20	0	1
628	OKLAUNION HVDC INTER - TX	Distribution		345.00	26.40	26.40	540.40	2	0
629	OKLAUNION HVDC INTER - TX	Distribution		345.00	0.00	0.00	0.00	0	0
630	OVER STREET - TX	Transmission		69.00	13.09	4.16	25.00	1	0
631	OWLS - TX	Transmission		138.00	69.00	13.09	90.00	1	0
632	OZONA - TX	Transmission		69.00	13.09	0.00	12.50	1	0
633	PADUCAH - TX	Transmission		69.00	12.50	0.00	3.75	3	0
634	PAINT CREEK PLANT - TX	Transmission		138.00	70.50	36.20	90.00	1	0
635	PAINT ROCK - TX	Transmission		69.00	4.10	0.00	333.67	3	0
636	PAISANO - TX	Distribution		69.00	12.50	0.00	0.50	1	0
637	PAN AMERICAN - TX	Distribution		69.00	2.40	0.00	0.15	1	0
638	PANDALE 69KV SUB - TX	Transmission		69.00	13.09	0.00	12.00	1	0

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639	PEACOCK (WT) - TX	Transmission		69.00	2.40	0.00	0.60	3	0
640	PECAN BAYOU - TX	Transmission		138.00	12.47	0.00	28.00	1	0
641	PERKINS-PROTHO - TX	Distribution		69.00	12.50	0.00	1.00	3	0
642	POWELL FIELD - TX	Distribution		69.00	0.00	0.00	0.00	0	0
643	POWELL FIELD - TX	Distribution		69.00	13.09	0.00	15.00	1	0
644	POWELL SHELL - TX	Distribution		69.00	4.00	0.00	5.00	3	0
645	PUNCHER 69KV - TX	Distribution		69.00	0.00	0.00	0.00	0	0
646	PUNCHER 69KV - TX	Distribution		69.00	13.09	0.00	7.50	1	0
647	PUTNAM - TX	Distribution		138.00	138.00	0.00	150.00	1	0
648	PUTNAM - TX	Distribution		138.00	70.50	12.47	90.00	1	0
649	PUTNAM - TX	Distribution		138.00	0.00	0.00	0.00	0	0
650	PUTNAM 69KV - TX	Distribution		69.00	12.50	0.00	3.75	1	0
651	QUANAH - TX	Distribution		69.00	12.00	0.00	15.00	3	0
652	RADIUM - TX	Distribution		138.00	69.00	7.83	62.50	1	0
653	RAINEY CREEK - TX	Distribution		138.00	13.09	13.80	28.00	1	0
654	RANKIN - TX	Distribution		69.00	13.09	0.00	10.00	1	0
655	REBECCA LANE - TX	Distribution		138.00	13.09	5.67	25.00	1	0
656	RIO PECOS PLANT (GIRVIN) - TX	Distribution		138.00	0.00	0.00	0.00	0	0
657	RIO PECOS PLANT (GIRVIN) - TX	Transmission		138.00	69.00	13.80	62.50	1	0
658	RIO PECOS PLANT (GIRVIN) - TX	Distribution		138.00	0.00	0.00	0.00	0	0
659	RIO PECOS PLANT (GIRVIN) - TX	Transmission		138.00	70.50	13.09	54.00	1	0
660	RISING STAR - TX	Transmission		69.00	13.00	0.00	3.75	1	0
661	ROARING SPRINGS - TX	Transmission		69.00	12.47	0.00	6.25	1	0
662	ROBERT LEE - TX	Transmission		69.00	13.00	0.00	10.50	1	0
663	ROBERTSON PRISON - TX	Transmission		69.00	7.50	0.00	9.30	3	0
664	ROBY - TX	Transmission		69.00	13.00	0.00	6.20	1	0
665	ROCHESTER - TX	Transmission		69.00	12.47	0.00	5.00	1	0
666	ROTAN - TX	Transmission		69.00	7.56	0.00	9.20	2	0
667	ROTAN - TX	Transmission		69.00	13.00	0.00	3.33	1	0
668	ROTAN GYP MILL EAST - TX	Distribution		12.00	0.48	0.00	3.00	6	0
669	ROUND TOP - TX	Distribution		69.00	13.00	0.00	12.50	1	0
670	ROWENA - TX	Distribution		69.00	13.00	0.00	4.69	1	0
671	RUSSEK STREET - TX	Distribution		138.00	0.00	0.00	0.00	0	0
672	RUSSEK STREET - TX	Transmission		138.00	13.09	0.00	50.00	2	0
673	RUSTHILL - TX	Distribution		138.00	70.50	13.09	78.00	1	0
674	S.A. AVENUE N. - TX	Distribution		69.00	13.00	0.00	22.40	1	0
675	S.A. BEN FICKLIN - TX	Distribution		138.00	13.09	0.00	28.00	1	0
676	S.A. COKE ST - TX	Distribution		138.00	13.09	0.00	28.00	1	0
677	S.A. COLLEGE HILLS WEST - TX	Distribution		138.00	13.09	0.00	22.40	1	0
678	S.A. COLLEGE HILLS WEST - TX	Distribution		69.00	0.00	0.00	0.00	0	0
679	S.A. COLLEGE HILLS WEST - TX	Distribution		138.00	13.09	0.00	28.00	1	0
680	S.A. CONCHO PLANT - TX	Distribution		138.00	12.47	0.00	28.00	1	0
681	S.A. EMERSON ST. - TX	Distribution		69.00	13.00	0.00	28.00	1	0
682	S.A. GRAPE CREEK - TX	Distribution		69.00	13.09	0.00	10.00	3	0
683	S.A. HIGHLAND - TX	Distribution		138.00	13.09	0.00	28.00	1	0
684	S.A. JACKSON ST. - TX	Distribution		69.00	13.00	0.00	56.00	2	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)
685	S.A. LAKE DRIVE - TX	Distribution		138.00	13.09	0.00	28.00	1	0
686	S.A. MATHIS AIR FIELD - TX	Transmission		69.00	4.36	0.00	9.40	1	0
687	S.A. NORTH - TX	Transmission		69.00	13.00	0.00	28.00	1	0
688	S.A. NORTH - TX	Transmission		0.00	0.00	0.00	0.00	0	0
689	S.A. NORTH - TX	Distribution		138.00	69.00	6.57	62.50	1	0
690	S.A. PAULANN - TX	Distribution		138.00	12.47	0.00	25.00	1	0
691	S.A. RED CREEK - TX	Transmission		345.00	138.00	13.80	900.00	2	0
692	S.A. RED CREEK - TX	Distribution		0.00	0.00	0.00	0.00	0	0
693	S.A. RED CREEK - TX	Distribution		345.00	345.00	345.00	0.00	0	0
694	S.A. SOUTH - TX	Distribution		0.00	0.00	0.00	0.00	0	0
695	S.A. SOUTH - TX	Transmission		69.00	12.47	0.00	28.00	1	0
696	S.A. SOUTHLAND HILLS - TX	Transmission		138.00	13.09	0.00	28.00	1	0
697	Sage - TX	Transmission		69.00	12.50	0.00	25.00	1	0
698	SAN ANGELO POWER - TX	Transmission		138.00	69.00	13.09	416.00	4	0
699	SAN ANGELO POWER - TX	Distribution		138.00	70.50	13.09	416.00	4	0
700	SANTA ANNA - TX	Distribution		138.00	69.00	14.40	33.60	1	0
701	SANTA ANNA - TX	Distribution		69.00	13.09	0.00	6.25	1	0
702	SANTA RITA - TX	Distribution		69.00	13.09	0.00	30.00	2	0
703	SARAGOSA - TX	Transmission		138.00	70.50	13.09	54.00	1	0
704	SARAGOSA - TX	Distribution		69.00	0.00	0.00	0.00	0	0
705	SARAGOSA - TX	Distribution		138.00	69.00	13.09	15.00	1	0
706	SHAFTER MINE - TX	Distribution		69.00	12.00	0.00	22.50	3	0
707	SHEFFIELD (WT) - TX	Distribution		69.00	7.56	0.00	10012.00	12	0
708	SHELTON STREET - TX	Distribution		69.00	13.00	0.00	25.00	1	0
709	SHELTON STREET - TX	Distribution		69.00	13.09	2.40	15.00	1	0
710	SILVER - TX	Transmission		69.00	0.00	0.00	0.00	0	0
711	SILVER - TX	Transmission		69.00	0.00	0.00	0.00	0	0
712	SILVER - TX	Transmission		69.00	12.47	0.00	25.00	1	0
713	SOLSTICE - TX	Distribution		345.00	138.00	34.50	405.00	1	0
714	SOLSTICE - TX	Distribution		138.00	0.00	0.00	0.00	0	0
715	SOLSTICE - TX	Distribution		138.00	138.00	138.00	150.00	1	0
716	SOLSTICE - TX	Transmission		345.00	138.00	13.80	675.00	1	0
717	SOLSTICE - TX	Transmission		138.00	0.00	0.00	0.00	0	0
718	SONORA - TX	Transmission		69.00	13.00	0.00	10.00	3	0
719	SONORA - TX	Transmission		138.00	0.00	0.00	0.00	0	0
720	SONORA ATLANTIC - TX	Transmission		69.00	12.00	0.00	1.50	3	0
721	SONORA ATLANTIC - TX	Distribution		69.00	13.09	0.00	5.00	1	0
722	SONORA CITY - TX	Distribution		69.00	13.00	0.00	12.50	1	0
723	SONORA CITY - TX	Distribution		69.00	0.00	0.00	0.00	0	0
724	SOUTH CROSS - TX	Distribution		69.00	0.00	0.00	0.00	0	0
725	SOUTH CROSS - TX	Distribution		69.00	4.10	0.00	7.50	3	0
726	SOUTHWEST VERNON - TX	Distribution		138.00	69.00	13.09	130.00	1	0
727	SPUDDER FLAT - TX	Transmission		138.00	12.47	0.00	9.38	1	0
728	SPUR - TX	Transmission		138.00	69.00	5.10	56.00	1	0
729	SPUR - TX	Transmission		69.00	0.00	0.00	0.00	0	0
730	SPUR - TX	Distribution		69.00	7.56	0.00	2.50	3	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
731	SPUR - TX	Transmission		69.00	2.52	0.00	2.00	2	0
732	SPUR - TX	Transmission		69.00	4.10	0.00	1.00	1	0
733	STAMFORD - TX	Transmission		69.00	13.00	0.00	28.00	1	0
734	STAMFORD PUMP - TX	Transmission		69.00	13.10	0.00	1.00	1	0
735	STAMFORD PUMP - TX	Distribution		69.00	12.50	0.00	0.83	1	0
736	STAMFORD PUMP - TX	Distribution		69.00	13.09	0.00	0.83	1	0
737	SWENSON - TX	Distribution		69.00	12.50	0.00	0.65	3	0
738	TALPA ATLANTIC - TX	Distribution		69.00	13.00	0.00	1.00	2	0
739	TALPA ATLANTIC - TX	Distribution		69.00	13.00	0.00	500.50	2	0
740	TALPA ATLANTIC - TX	Transmission		69.00	13.10	0.00	500.50	2	0
741	TALPA ATLANTIC - TX	Transmission		69.00	7.20	0.00	1.00	3	0
742	TANKERSLEY - TX	Transmission		69.00	13.00	0.00	4.69	1	0
743	TEXAS-NEW MEXICO - TX	Transmission		69.00	13.09	0.00	20.00	1	0
744	TEXAS-NEW MEXICO - TX	Distribution		69.00	4.00	0.00	2.50	3	0
745	THROCKMORTON - TX	Distribution		69.00	13.00	0.00	4.68	1	0
746	THROCKMORTON WOODSON OIL CO - TX	Distribution		69.00	7.20	0.00	1.00	3	0
747	TRENT (WT) - TX	Distribution		69.00	7.20	0.00	3.00	3	0
748	TRUSCOTT CITY - TX	Distribution		69.00	12.47	0.00	0.33	1	0
749	TRUSCOTT CITY - TX	Distribution		69.00	7.20	0.00	0.67	2	0
750	TRUSCOTT HUMBLE - TX	Distribution		34.50	2.30	0.00	0.90	3	0
751	TURKEY - TX	Distribution		69.00	13.00	0.00	4.20	1	0
752	TUSCOLA - TX	Distribution		69.00	0.00	0.00	0.00	0	0
753	TUSCOLA - TX	Transmission		69.00	13.00	0.00	9.38	1	0
754	TUSCOLA - TX	Transmission		69.00	12.47	0.00	9.38	1	0
755	TWILIGHT TRAILS - TX	Transmission		138.00	13.09	0.00	20.00	1	0
756	VALENTINE TAP - TX	Transmission		69.00	7.20	0.00	1.00	2	0
757	VALENTINE TAP - TX	Distribution		69.00	13.00	0.00	0.50	1	0
758	VALERA - TX	Distribution		69.00	12.47	0.00	0.50	3	0
759	VERNON MAIN ST. SUB. - TX	Transmission		138.00	0.00	0.00	0.00	0	0
760	VERNON MAIN ST. SUB. - TX	Transmission		69.00	13.00	0.00	10.00	1	0
761	VERNON MAIN ST. SUB. - TX	Distribution		138.00	69.00	0.00	62.50	1	0
762	VERNON PLANT SUB - TX	Distribution		69.00	12.47	0	14	1	0
763	VOGEL STREET - TX	Transmission		69.00	13.00	0	25	1	0
764	WAGGONER REFINERY - TX	Distribution		69.00	7.00	0	1	1	0
765	WAGGONER REFINERY - TX	Distribution		69.00	7.20	0	2	2	0
766	WALNUT STREET - TX	Distribution		69.00	13.00	0	20	1	0
767	WEINERT - TX	Distribution		69.00	13.09	0	3	1	0
768	WINTERS - TX	Distribution		69.00	12.47	0	11	1	0
769	WOLFBERRY - TX	Distribution		138.00	0.00	0	0	0	0
770	WYLIE CHAMPION - TX	Distribution		138.00	13.09	6	25	1	0
771	TotalDistributionSubstationMember								
772	TotalTransmissionSubstationMember								
773	Total								

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	STATCAP	1	57.60
2	Air Core Reactor	6	0.00
3	STATCAP	3	26.30
4		0	0.00
5		0	0.00
6		0	0.00
7		0	0.00
8		0	0.00
9		0	0.00
10	STATCAP	1	0.00
11		0	0.00
12	XSLR - 0.4mH / 480A	3	0.00
13	STATCAP	2	4.80
14		0	0.00
15		0	0.00
16	STATCAP	1	14.40
17		0	0.00
18	STATCAP	1	14.40
19		0	0.00
20		0	0.00
21		0	0.00
22	STATCAP	1	14.40
23		0	0.00
24	STATCAP	3	45.60
25		0	0.00
26		0	0.00
27	STATCAP	1	0.00
28	STATCAP	1	7.20
29	STATCAP	1	14.40
30		0	0.00
31		0	0.00
32		0	0.00
33		0	0.00
34		0	0.00
35		0	0.00
36		0	0.00
37		0	0.00
38		0	0.00
39		0	0.00
40		0	0.00
41		0	0.00
42		0	0.00
43		0	0.00
44		0	0.00
45		0	0.00
46		0	0.00
47		0	0.00
48		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
49	STATCAP	2	7.20
50		0	0.00
51		0	0.00
52		0	0.00
53		0	0.00
54		0	0.00
55		0	0.00
56		0	0.00
57		0	0.00
58		0	0.00
59		0	0.00
60		0	0.00
61	STATCAP	1	2.40
62		0	0.00
63	STATCAP	1	28.80
64		0	0.00
65		0	0.00
66		0	0.00
67	Air Core Reactor	12	127.36
68		0	0.00
69		0	0.00
70		0	0.00
71		0	0.00
72		0	0.00
73		0	0.00
74	XSLR - 0.6mH / 480A	3	0.11
75	STATCAP	1	23.00
76		0	0.00
77		0	0.00
78		0	0.00
79		0	0.00
80		0	0.00
81		0	0.00
82	STATCAP	2	113.40
83	Air Core Reactor	6	0.00
84	STATCAP	3	26.30
85		0	0.00
86		0	0.00
87		0	0.00
88		0	0.00
89		0	0.00
90	STATCAP	2	4.80
91		0	0.00
92	STATCAP	2	31.20
93	Air Core Reactor	3	0.00
94		0	0.00
95		0	0.00
96		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
97	2000A Air-Core Reactor	3	0.00
98		0	0.00
99		0	0.00
100	STATCAP	2	4.80
101		0	0.00
102		0	0.00
103		0	0.00
104	STATCAP	2	4.80
105		0	0.00
106	STATCAP	1	14.40
107		0	0.00
108	REACTIVE SPECIAL	6	0.00
109	STATCAP	2	0.00
110		0	0.00
111	STATCAP	1	14.40
112		0	0.00
113		0	0.00
114		0	0.00
115		0	0.00
116		0	0.00
117	XSLR - 0.6mH / 480A	3	0.00
118	STATCAP	2	115.20
119	STATCAP	1	0.00
120		0	0.00
121		0	0.00
122		0	0.00
123		0	0.00
124		0	0.00
125		0	0.00
126	STATCAP	1	10.80
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		0	0.00
134	STATCAP	2	4.80
135		0	0.00
136		0	0.00
137		0	0.00
138	STATCAP	2	4.80
139		0	0.00
140		0	0.00
141		0	0.00
142		0	0.00
143		0	0.00
144		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
145		0	0.00
146		0	0.00
147		0	0.00
148		0	0.00
149		0	0.00
150		0	0.00
151		0	0.00
152		0	0.00
153		0	0.00
154		0	0.00
155		0	0.00
156		0	0.00
157		0	0.00
158		0	0.00
159		0	0.00
160	STATCAP	1	2.40
161	STATCAP	2	43.20
162		0	0.00
163		0	0.00
164		0	0.00
165		0	0.00
166		0	0.00
167	STATCAP	1	28.80
168		0	0.00
169		0	0.00
170	STATCAP	2	0.00
171	Air Core Reactor	3	0.00
172	XSLR - 0.6mH / 480A	6	0.00
173		0	0.00
174		0	0.00
175	Air Core Reactor	6	0.00
176		0	0.00
177	STATCAP	1	28.80
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		0	0.00
188	Air Core Reactor	2	28,200.00
189		0	0.00
190		0	0.00
191	STATCAP	2	0.00
192	Air Core Reactor	1	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
193		0	0.00
194		0	0.00
195	STATCAP	1	14.40
196		0	0.00
197		0	0.00
198	STATCAP	1	28.80
199	XSLR - 0.6mH / 480A	3	0.00
200	STATCAP	1	24.00
201		0	0.00
202		0	0.00
203		0	0.00
204	STATCAP	1	2.40
205		0	0.00
206		0	0.00
207	STATCAP	2	2.40
208		0	0.00
209		0	0.00
210		0	0.00
211		0	0.00
212		0	0.00
213		0	0.00
214		0	0.00
215		0	0.00
216		0	0.00
217		0	0.00
218	STATCAP	2	0.00
219	XSLR - 0.6mH / 480A	6	0.00
220		0	0.00
221		0	0.00
222		0	0.00
223		0	0.00
224		0	0.00
225	STATCAP	1	15.40
226	XSLR - 0.6mH / 480A	3	0.00
227		0	0.00
228		0	0.00
229		0	0.00
230	STATCAP	1	0.00
231		0	0.00
232		0	0.00
233		0	0.00
234		0	0.00
235	STATCAP	2	86.40
236		0	0.00
237		0	0.00
238		0	0.00
239		0	0.00
240		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
241		0	0.00
242		0	0.00
243		0	0.00
244		0	0.00
245	3000A Air-Core Reactor	6	0.00
246		0	0.00
247	STATCAP	1	50.00
248		0	0.00
249	Air Core Reactor	3	0.00
250	STATCAP	1	933.00
251	REACTOR	1	14.80
252		0	0.00
253		0	0.00
254	STATCAP	1	2.40
255		0	0.00
256	STATCAP	1	14.40
257		0	0.00
258		0	0.00
259		0	0.00
260	STATCAP	1	2.40
261		0	0.00
262		0	0.00
263		0	0.00
264		0	0.00
265		0	0.00
266		0	0.00
267		0	0.00
268	STATCAP	2	7.20
269		0	0.00
270		0	0.00
271		0	0.00
272		0	0.00
273		0	0.00
274		0	0.00
275		0	0.00
276	Air Core Reactor	6	0.00
277	STATCAP	1	28.80
278		0	0.00
279		0	0.00
280		0	0.00
281		0	0.00
282		0	0.00
283		0	0.00
284		0	0.00
285	STATCAP	5	19.20
286		0	0.00
287	STATCAP	2	4.80
288		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
289		0	0.00
290	STATCAP	1	7.20
291		0	0.00
292		0	0.00
293		0	0.00
294	REACTIVE SPECIAL	1	0.00
295		0	0.00
296		0	0.00
297		0	0.00
298		0	0.00
299		0	0.00
300	STATCAP	1	7.20
301		0	0.00
302		0	0.00
303		0	0.00
304		0	0.00
305		0	0.00
306	STATCAP	4	9.60
307	STATCAP	1	18.00
308		0	0.00
309		0	0.00
310		0	0.00
311		0	0.00
312	STATCAP	1	0.00
313		0	0.00
314	STATCAP	1	28.80
315		0	0.00
316		0	0.00
317	STATCAP	2	104.64
318		0	0.00
319		0	0.00
320	Air Core Reactor	3	0.00
321		0	0.00
322	STATCAP	1	10.80
323	STATCAP	1	2.40
324		0	0.00
325		0	0.00
326		0	0.00
327		0	0.00
328		0	0.00
329		0	0.00
330		0	0.00
331		0	0.00
332		0	0.00
333		0	0.00
334		0	0.00
335		0	0.00
336		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
337		0	0.00
338		0	0.00
339		0	0.00
340	XSLR - 0.6mH / 480A	3	0.00
341	STATCAP	1	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		0	0.00
349	STATCAP	1	50.40
350		0	0.00
351		0	0.00
352		0	0.00
353		0	0.00
354	STATCAP	1	28.80
355	STATCAP	1	2.40
356		0	0.00
357		0	0.00
358	STATCAP	1	0.00
359		0	0.00
360		0	0.00
361		0	0.00
362		0	0.00
363		0	0.00
364	STATCAP	2	57.60
365		0	0.00
366		0	0.00
367		0	0.00
368		0	0.00
369		0	0.00
370		0	0.00
371		0	0.00
372	STATCAP	2	0.00
373		0	0.00
374		0	0.00
375		0	0.00
376	STATCAP	1	14.40
377	Air Core Reactor	3	0.00
378		0	0.00
379	STATCAP	1	14.40
380		0	0.00
381		0	0.00
382		0	0.00
383		0	0.00
384	XSLR - 0.4mH / 480A	3	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
385		0	0.00
386	STATCAP	1	28.70
387		0	0.00
388		0	0.00
389		0	0.00
390		0	0.00
391		0	0.00
392		0	0.00
393	STATCAP	2	57.60
394	STATCAP	2	115.20
395	XSLR - 0.6mH / 480A	3	0.00
396	Reactor	3	0.00
397	STATCAP	1	72.00
398	STATCAP	1	28.80
399		0	0.00
400	XSLR - 0.6mH / 480A	3	0.00
401	STATCAP	1	18.00
402		0	0.00
403		0	0.00
404		0	0.00
405		0	0.00
406	STATCAP	2	57.60
407		0	0.00
408		0	0.00
409	K06766-E100 138kV 2000A 19 Ohm Air-Core Reactor	8	0.00
410		0	0.00
411		0	0.00
412	XSLR - 0.6mH / 480A	3	0.00
413	STATCAP	1	0.00
414	STATCAP	1	14.40
415		0	0.00
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
425		0	0.00
426	STATCAP	1	28.80
427		0	0.00
428		0	0.00
429		0	0.00
430		0	0.00
431		0	0.00
432	STATCAP	2	57.60

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
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		0	0.00
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		0	0.00
451		0	0.00
452		0	0.00
453	STATCAP	1	7.20
454		0	0.00
455		0	0.00
456	STATCAP	1	3.60
457		0	0.00
458		0	0.00
459		0	0.00
460		0	0.00
461		0	0.00
462		0	0.00
463		0	0.00
464		0	0.00
465	Air Core Reactor	1	0.00
466		0	0.00
467	STATCAP	1	57.60
468	Air Core Reactor	12	0.00
469		0	0.00
470		0	0.00
471	STATCAP	2	14.40
472		0	0.00
473	STATCAP	1	6.00
474		0	0.00
475	STATCAP	2	14.40
476		0	0.00
477		0	0.00
478		0	0.00
479		0	0.00
480		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
481		0	0.00
482		0	0.00
483		0	0.00
484		0	0.00
485		0	0.00
486		0	0.00
487		0	0.00
488		0	0.00
489	STATCAP	2	28.80
490		0	0.00
491		0	0.00
492	STATCAP	1	12.00
493		0	0.00
494		0	0.00
495		0	0.00
496		0	0.00
497		0	0.00
498		0	0.00
499	STATCAP	1	0.45
500		0	0.00
501		0	0.00
502		0	0.00
503	STATCAP	1	12.00
504		0	0.00
505		0	0.00
506		0	0.00
507	STATCAP	1	200.00
508	STATCAP	1	56.70
509		0	0.00
510		0	0.00
511		0	0.00
512		0	0.00
513		0	0.00
514	STATCAP	2	28.80
515		0	0.00
516		0	0.00
517		0	0.00
518		0	0.00
519		0	0.00
520		0	0.00
521		0	0.00
522		0	0.00
523		0	0.00
524		0	0.00
525		0	0.00
526		0	0.00
527		0	0.00
528	STATCAP	1	12.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
529		0	0.00
530		0	0.00
531		0	0.00
532		0	0.00
533		0	0.00
534		0	0.00
535		0	0.00
536		0	0.00
537	STATCAP	1	3.60
538		0	0.00
539	STATCAP	1	7.20
540		0	0.00
541		0	0.00
542		0	0.00
543		0	0.00
544		0	0.00
545	DRCS	1	10.00
546	STATCAP	2	57.60
547		0	0.00
548		0	0.00
549		0	0.00
550		0	0.00
551	STATCAP	1	28.80
552		0	0.00
553		0	0.00
554		0	0.00
555		0	0.00
556		0	0.00
557		0	0.00
558		0	0.00
559		0	0.00
560		0	0.00
561		0	0.00
562		0	0.00
563		0	0.00
564		0	0.00
565		0	0.00
566		0	0.00
567		0	0.00
568		0	0.00
569		0	0.00
570		0	0.00
571		0	0.00
572		0	0.00
573		0	0.00
574		0	0.00
575		0	0.00
576	STATCAP	1	9.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
577	STATCAP	1	6.00
578		0	0.00
579		0	0.00
580		0	0.00
581		0	0.00
582		0	0.00
583		0	0.00
584		0	0.00
585		0	0.00
586		0	0.00
587	STATCAP	2	57.60
588	REACTIVE SPECIAL	1	64.20
589		0	0.00
590		0	0.00
591		0	0.00
592		0	0.00
593		0	0.00
594		0	0.00
595	STATCAP	1	7.20
596		0	0.00
597		0	0.00
598		0	0.00
599		0	0.00
600		0	0.00
601		0	0.00
602		0	0.00
603		0	0.00
604	STATCAP	1	1.80
605		0	0.00
606	STATCAP	1	7.20
607		0	0.00
608		0	0.00
609		0	0.00
610		0	0.00
611		0	0.00
612	STATCAP	1	12.00
613		0	0.00
614		0	0.00
615		0	0.00
616		0	0.00
617	1200A Air-Core Reactor	3	0.00
618		0	0.00
619	REACTIVE SPECIAL	1	0.00
620	STATCAP	1	28.80
621		0	0.00
622		0	0.00
623		0	0.00
624		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
625		0	0.00
626		0	0.00
627		0	0.00
628		0	0.00
629	REACTIVE SPECIAL	8	0.00
630		0	0.00
631		0	0.00
632		0	0.00
633		0	0.00
634		0	0.00
635		0	0.00
636		0	0.00
637		0	0.00
638		0	0.00
639		0	0.00
640		0	0.00
641		0	0.00
642	STATCAP	2	9.00
643		0	0.00
644		0	0.00
645	STATCAP	1	7.20
646		0	0.00
647		0	0.00
648		0	0.00
649	STATCAP	1	28.80
650		0	0.00
651		0	0.00
652		0	0.00
653		0	0.00
654		0	0.00
655		0	0.00
656	Air Core Reactor	7	140.00
657		0	0.00
658	STATCAP	1	28.80
659		0	0.00
660		0	0.00
661		0	0.00
662		0	0.00
663		0	0.00
664		0	0.00
665		0	0.00
666		0	0.00
667		0	0.00
668		0	0.00
669		0	0.00
670		0	0.00
671	STATCAP	3	46.80
672		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
673		0	0.00
674		0	0.00
675		0	0.00
676		0	0.00
677		0	0.00
678	STATCAP	1	21.60
679		0	0.00
680		0	0.00
681		0	0.00
682		0	0.00
683		0	0.00
684		0	0.00
685		0	0.00
686		0	0.00
687		0	0.00
688	STATCAP	1	21.60
689		0	0.00
690		0	0.00
691		0	0.00
692	STATCAP	2	50.40
693	REACTOR	1	0.00
694	STATCAP	1	2.40
695		0	0.00
696		0	0.00
697		0	0.00
698		0	0.00
699		0	0.00
700		0	0.00
701		0	0.00
702		0	0.00
703		0	0.00
704	STATCAP	1	150.00
705		0	0.00
706		0	0.00
707		0	0.00
708		0	0.00
709		0	0.00
710	STATCAP	1	7.20
711	STATCAP	1	7.20
712		0	0.00
713		0	0.00
714	STATCAP	2	14.40
715		0	0.00
716		0	0.00
717	REACTIVE SPECIAL	6	0.00
718		0	0.00
719	STATCAP	2	57.60
720		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
721		0	0.00
722		0	0.00
723	STATCAP	1	12.00
724	STATCAP	1	3.60
725		0	0.00
726		0	0.00
727		0	0.00
728		0	0.00
729	STATCAP	1	12.00
730		0	0.00
731		0	0.00
732		0	0.00
733		0	0.00
734		0	0.00
735		0	0.00
736		0	0.00
737		0	0.00
738		0	0.00
739		0	0.00
740		0	0.00
741		0	0.00
742		0	0.00
743		0	0.00
744		0	0.00
745		0	0.00
746		0	0.00
747		0	0.00
748		0	0.00
749		0	0.00
750		0	0.00
751		0	0.00
752	STATCAP	1	14.40
753		0	0.00
754		0	0.00
755		0	0.00
756		0	0.00
757		0	0.00
758		0	0.00
759	STATCAP	2	28.80
760		0	0.00
761		0	0.00
762		0	0
763		0	0
764		0	0
765		0	0
766		0	0
767		0	0
768		0	0

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
769	STATCAP	2	29
770		0	0
771			31,642
772			933
773			32,575

Name of Respondent: AEP Texas	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	A. Ray King Transmission Training Facility	[(a)] OPCo	921	257,657
3	Information Technology	AEPSC	920, 923	8,489,933
4	Administrative and General Expenses - Maintenance	AEPSC	935	4,886,800
5	Infrastructure Ops & Support	AEPSC	920, 923	1,296,575
6	Administrative and General Expenses - Operation	AEPSC	920, 921, 922, 923, 925, 926, 928, 930.1, 930.2, 931	1,501,361
7	Legal GC/Administration	AEPSC	920, 923	3,676,103
8	Audit Services	AEPSC	920, 923	1,014,733
9	Materials and Supplies	APCo	107, 935	760,076
10	Central Machine Shop	APCo	107, 108, 592	289,201
11	Materials and Supplies	OHTCo	107, 570	522,327
12	Civil & Political Activities and Other Svcs	AEPSC	426.1, 426.3, 426.4, 426.5	529,080
13	Materials and Supplies	OPCo	107, 184, 570, 592, 930	1,660,230
14	Construction Services	AEPSC	107, 108	138,441,481
15	Materials and Supplies	PSO	107, 108, 186, 592	1,586,634
16	Construction Services	SWEPCo	107, 108	926,577
17	Materials and Supplies	SWEPCo	107, 184, 570, 930	487,929
18	Corp Safety & Health	AEPSC	920, 923	1,346,843
19	Physical & Cyber Security	AEPSC	920, 923	743,318
20	Corporate Accounting	AEPSC	920, 923	2,067,991
21	Research and Other Services	AEPSC	183, 186, 188	1,038,369
22	Corporate Planning & Budgeting	AEPSC	920, 923	1,083,466
23	Steam Power Generation - Operation	AEPSC	500, 501, 506, 508	372,139
24	Customer Accounts Expenses	AEPSC	901, 902, 903, 904, 905	6,462,549
25	Supply Chain & Fleet and Property Management	AEPSC	920, 923	2,523,248
26	Distribution Expenses - Maintenance	AEPSC	590, 591, 592, 593, 594, 595, 597, 598	331,089
27	Tax Services	AEPSC	920, 923	1,038,269
28	Distribution Expenses - Maintenance	SWEPCo	593, 594, 595, 596	326,448
29	Transmission Expenses - Maintenance	AEPSC	568, 569, 569.1, 569.2, 570, 571, 572, 573	2,149,386
30	Distribution Expenses - Operation	AEPSC	580, 581, 582, 583, 584, 586, 587, 588	6,139,985
31	Transmission Expenses - Operation	AEPSC	560, 561.2, 561.3, 561.4, 561.5, 562, 563, 566, 920, 923	26,455,318
32	Federal Affairs	AEPSC	920, 923	685,598
33	Treasury & Risk	AEPSC	920, 923	4,181,603
34	Fuel & Storeroom Services	AEPSC	152, 163, 163.1	6,307,159
35	Human Resources	AEPSC	920, 923	4,993,921
19				
20	**Non-power Goods or Services Provided for Affiliated**			

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)
21	Non-power Goods or Services Provided for Affiliate			
22	Building and Property Leases	AEPSC	454	4,860,487
23	Construction Services	ETT	106, 107, 108	5,177,273
24	Construction Services	PSO	107, 108	280,119
25	Construction Services	SWEPCo	107, 108	2,655,066
26	Distribution Expenses - Maintenance	PSO	592, 593, 594, 595	385,468
27	Distribution Expenses - Maintenance	SWEPCo	592, 593, 594, 595, 597	1,312,863
28	HVDC North Tie	PSO	560, 562, 566, 570, 922, 925, 926	1,524,714
29	Materials and Supplies	ETT	154	2,936,500
30	Materials and Supplies	OKTCo	154	842,591
31	Materials and Supplies	OPCo	154	423,620
32	Materials and Supplies	PSO	154	384,626
33	Materials and Supplies	SWEPCo	154	1,240,775
34	Transmission Expenses - Maintenance	ETT	568, 569, 570, 571, 573	1,813,155
35	Transmission Expenses - Maintenance	SWEPCo	570, 571	366,085
36	Transmission Expenses - Operation	ETT	560, 562, 563, 566	2,647,829
42				
Page 429				

Name of Respondent: AEP Texas	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):

AEPSC - American Electric Power Service Corporation
ETT - Electric Transmission TX, LLC
OPCo - Ohio Power Company
APCo - Appalachian Power Company
PSO - Public Service Company of Oklahoma
SWEPCo - Southwestern Electric Power Company
OKTCo - AEP Oklahoma Transmission Company, Inc
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.

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.

Various Account Listings As Provided in Column (c)	FERC Accounts: