

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)

Entergy Arkansas, LLC

Year/Period of Report
End of: 2025/ Q4

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

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- one million megawatt hours of total annual sales,
- 100 megawatt hours of annual sales for resale,
- 500 megawatt hours of annual power exchanges delivered, or
- 500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

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

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

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

<u>Schedules</u>	<u>Pages</u>
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

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.

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-fags-efilingferc-online>.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;

"project" means, a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit

When to Submit

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

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

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

Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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.

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

"Sec. 4. The Commission is hereby authorized and empowered

"To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies".10

"Sec. 309.

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 filed..."

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 Entergy Arkansas, LLC		02 Year/ Period of Report End of: 2025/ 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) 425 West Capital Avenue, Little Rock, AR 72201		
05 Name of Contact Person Gina G. Bellott		06 Title of Contact Person Sr. Staff Accountant
07 Address of Contact Person (Street, City, State, Zip Code) 639 Loyola Avenue, New Orleans, Louisiana 70113		
08 Telephone of Contact Person, Including Area Code (504) 858-3276	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/03/2026

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 Reginald T. Jackson	03 Signature Reginald T. Jackson	04 Date Signed (Mo, Da, Yr) 04/03/2026
02 Title Sr VP & Chief Accounting Officer		

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: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)
	<u>Identification</u>	1	
	<u>List of Schedules</u>	2	
1	<u>General Information</u>	101	
2	<u>Control Over Respondent</u>	102	
3	<u>Corporations Controlled by Respondent</u>	103	
4	<u>Officers</u>	104	
5	<u>Directors</u>	105	
6	<u>Information on Formula Rates</u>	106	
7	<u>Important Changes During the Year</u>	108	
8	<u>Comparative Balance Sheet</u>	110	
9	<u>Statement of Income for the Year</u>	114	
10	<u>Statement of Retained Earnings for the Year</u>	118	
12	<u>Statement of Cash Flows</u>	120	
12	<u>Notes to Financial Statements</u>	122	
13	<u>Statement of Accum Other Comp Income, Comp Income, and Hedging Activities</u>	122a	N/A
14	<u>Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep</u>	200	
15	<u>Nuclear Fuel Materials</u>	202	
16	<u>Electric Plant in Service</u>	204	
17	<u>Electric Plant Leased to Others</u>	213	N/A
18	<u>Electric Plant Held for Future Use</u>	214	
19	<u>Construction Work in Progress-Electric</u>	216	
20	<u>Accumulated Provision for Depreciation of Electric Utility Plant</u>	219	
21	<u>Investment of Subsidiary Companies</u>	224	
22	<u>Materials and Supplies</u>	227	
23	<u>Allowances and Environmental Credits</u>	228	
24	<u>Extraordinary Property Losses</u>	230a	N/A
25	<u>Unrecovered Plant and Regulatory Study Costs</u>	230b	
26	<u>Transmission Service and Generation Interconnection Study Costs</u>	231	N/A
27	<u>Other Regulatory Assets</u>	232	
28	<u>Miscellaneous Deferred Debits</u>	233	

29	<u>Accumulated Deferred Income Taxes</u>	234	
30	<u>Capital Stock</u>	250	N/A
31	<u>Other Paid-in Capital</u>	253	
32	<u>Capital Stock Expense</u>	254b	N/A
33	<u>Long-Term Debt</u>	256	
34	<u>Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax</u>	261	
35	<u>Taxes Accrued, Prepaid and Charged During the Year</u>	262	
36	<u>Accumulated Deferred Investment Tax Credits</u>	266	
37	<u>Other Deferred Credits</u>	269	
38	<u>Accumulated Deferred Income Taxes-Accelerated Amortization Property</u>	272	N/A
39	<u>Accumulated Deferred Income Taxes-Other Property</u>	274	
40	<u>Accumulated Deferred Income Taxes-Other</u>	276	
41	<u>Other Regulatory Liabilities</u>	278	
42	<u>Electric Operating Revenues</u>	300	
43	<u>Regional Transmission Service Revenues (Account 457.1)</u>	302	
44	<u>Sales of Electricity by Rate Schedules</u>	304	
45	<u>Sales for Resale</u>	310	
46	<u>Electric Operation and Maintenance Expenses</u>	320	
47	<u>Purchased Power</u>	326	
48	<u>Transmission of Electricity for Others</u>	328	
49	<u>Transmission of Electricity by ISO/RTOs</u>	331	N/A
50	<u>Transmission of Electricity by Others</u>	332	
51	<u>Miscellaneous General Expenses-Electric</u>	335	
52	<u>Depreciation and Amortization of Electric Plant (Account 403, 404, 405)</u>	336	
53	<u>Regulatory Commission Expenses</u>	350	
54	<u>Research, Development and Demonstration Activities</u>	352	
55	<u>Distribution of Salaries and Wages</u>	354	
56	<u>Common Utility Plant and Expenses</u>	356	N/A
57	<u>Amounts included in ISO/RTO Settlement Statements</u>	397	
58	<u>Purchase and Sale of Ancillary Services</u>	398	
59	<u>Monthly Transmission System Peak Load</u>	400	
60	<u>Monthly ISO/RTO Transmission System Peak Load</u>	400a	N/A
61	<u>Electric Energy Account</u>	401a	
62	<u>Monthly Peaks and Output</u>	401b	
63	<u>Steam Electric Generating Plant Statistics</u>	402	
63.1	<u>Renewable Generating Plant Statistics</u>	404	

64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	N/A
66.1	Energy Storage Operations (Large Plants)	414	N/A
66.2	Energy Storage Operations (Small Plants)	419	N/A
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	N/A
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: <input type="checkbox"/> Two copies will be submitted <input checked="" type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ 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. Reginald T. Jackson Senior Vice President and Chief Accounting Officer 639 Loyola Avenue, New Orleans, LA 70113			
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: TX Date of Incorporation: 2018-09-13 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. N/A (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. Arkansas, Missouri, and Tennessee - Electric Utility Service			
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) <input type="checkbox"/> Yes (2) <input checked="" type="checkbox"/> No			

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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.

As of December 31, 2025, all of the common membership interests in Entergy Arkansas are held by Entergy Utility Holding Company. As of December 31, 2025, Entergy Utility Holding Company's membership interests are held by:

Entergy Corporation 3.7% 459,503 shares
Entergy Utility Affiliates 23.4% multiple securities
Entergy Utility Assets Holdings 31.2% 3,886,154 shares
Entergy Utility Enterprises 13.2% 1,640,560 shares
Entergy Utility Group 2.8% 350,173 shares
EUHC Holdings 24.2% 3,006,086 shares
Unaffiliated third parties 1.5% multiple securities

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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	Arkansas Power & Light Company, LLC		100	
2	AR Searcy Partnership, LLC		100	

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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.

<u>Line No.</u>	<u>Title (a)</u>	<u>Name of Officer (b)</u>	<u>Salary for Year (c)</u>	<u>Date Started in Period (d)</u>	<u>Date Ended in Period (e)</u>
1	President and Chief Executive Officer of Entergy Arkansas	Laura R. Landreaux	453,353		
2	Chairman of the Board and Chief Executive Officer of Entergy Corporation	Andrew S. Marsh	0		
3	Executive Vice President and Chief Financial Officer	Kimberly A. Fontan	0		
4	Executive Vice President and Chief Operating Officer of Entergy Corporation (1)	Peter S. Norgeot, Jr.	0		2025-04-30
5	Executive Vice President and Chief Operating Officer of Entergy Corporation (2)	Kimberly Cook-Nelson	0	2025-05-01	
6	Executive Vice President and General Counsel	Marcus V. Brown	0		2025-12-01
7	Senior Vice President and General Counsel	Daniel T. Falstad	0	2025-12-01	
8	Executive Vice President and Chief Nuclear Officer (1)	Kimberly Cook-Nelson	0		2025-05-01
9	Executive Vice President and Chief Nuclear Officer (2)	John Dinelli	0	2025-05-01	
10	Senior Vice President and Chief Accounting Officer	Reginald T. Jackson	0		
11	Vice President and General Tax Counsel	Steven W. Brady	0		

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FOOTNOTE DATA			

(a) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(b) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(c) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(d) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(e) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(f) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(g) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(h) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(i) Concept: OfficerSalary
Salary not presented as individual was compensated by other System companies and not by Entergy Arkansas.
(j) Concept: OfficerSalary

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	Laura R. Landreaux - President and Chief Executive Officer of Entergy Arkansas	425 W. Capital Avenue, Little Rock, AR 72201	true	false
2	Kimberly A. Fontan - Executive Vice President and Chief Financial Officer	639 Loyola Avenue, New Orleans, LA 70113	true	false
3	Kimberly Cook-Nelson - Executive Vice President and Chief Operating Officer of Entergy Corporation	1340 Echelon Parkway, Jackson, MS 39213	true	false

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Arkansas Electric Cooperative Corporation (AECC) Wholesale Distribution Agreement RS No. 82 (WDS) - Baseline Tariff	Docket No. ER14-133
2	Arkansas Electric Cooperative Corporation (AECC) Wholesale Distribution Agreement RS No. 82 (WDS) - Amended Tariff	Docket No. ER18-1190
3	Arkansas Electric Cooperative Corporation (AECC) Wholesale Distribution Agreement RS No. 82 (WDS) - Amended Tariff	Docket No. ER19-858
4	Arkansas Electric Cooperative Corporation (AECC) Wholesale Distribution Agreement RS No. 82 (WDS) - Amended Tariff	Docket No. ER22-1529
5	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Baseline Tariff	Docket No. ER13-1508
6	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER16-2199
7	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER18-1247
8	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER21-348
9	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER21-915
10	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER21-1720
11	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER21-1997
12	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER21-2169
13	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER22-489
14	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER22-843
15	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER22-2332
16	Midcontinent Independent System Operator (MISO) FERC Electric Tariff - Fifth Revised Volume 1	Docket No. ER13-948
17	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER14-649
18	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER15-358
19	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER15-1436
20	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER16-227
21	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER16-1322
22	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER17-215
23	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER17-1549

24	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER17-1777
25	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER17-2579
26	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER18-1260
27	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER18-1982
28	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER19-652
29	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER19-1503
30	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER17-827
31	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER20-1449
32	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER20-1472
33	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER21-200
34	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER21-262
35	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER21-2693
36	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER22-1602
37	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER22-2202
38	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER22-2562
39	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER23-2707
40	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER23-1228
41	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER23-2821
42	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER24-1158
43	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER24-1499
44	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER24-2468
45	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER25-2899
46	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER25-3077
47	Rate Schedule No. 705: Entergy OpCos, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT or MSS-4 Replacement Tariff) - Amended Tariff	Docket No. ER25-3465
48	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-224
49	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-430
50	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1029
51	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1055
52	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1179
53	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1191
54	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1204
55	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1377
56	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1538
57	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1634

58	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-1905
59	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-2871
60	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-3067
61	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-3138
62	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER24-3141
63	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER25-323
64	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER25-324
65	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER25-2304
66	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER25-2600
67	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER25-3074
68	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER26-371
69	Midcontinent Independent System Operator (MISO)-FERC Electric Tariff	Docket No. ER25-507

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20250314-5336	03/14/2025	ER25-1635	(a) EAL Annual Informational MISO Attachment O Transmission Formula Rate Update	
2	20240718-5193	07/18/2024	ER14-133	(a) 2022 Biennial EAL Informational Wholesale Distribution Rate (WDS) Formula Update re: Distribution Agreement between EAL and AECC	RS No. 82
3	20250331-5224	03/31/2025	ER25-1825	MSS-4R Tariff Formula Rate Informational Filing	

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfFiling
Pursuant to the Federal Energy Regulatory Commission's orders in Docket Nos. EL12-35 and ER13-2379 and the Annual Update, Information Exchange, and Challenge Procedures of the Entergy Operating Companies set forth in Attachment O of the Midcontinent Independent System Operator, Inc.'s Open Access Transmission, Energy and Operating Reserve Markets Tariff, Entergy Services shall submit an annual Informational Filing on March 15 based on data for the second preceding calendar year data. The 2024 update was filed on March 14, 2025 in Docket No. ER25-1635. This Informational Filing is not a rate filing. It shows the development of the Entergy Operating Companies' annual transmission revenue requirements for billing June 1, 2024 through May 31, 2025 through the application of data for Calendar Year 2023 under the Attachment O MISO Tariff.
(b) Concept: DescriptionOfFiling
Filed biennially. The next biennial filing will be in 2026.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	111	Comparative Balance Sheet	(c)	57
2	117	Statement of Income for the Year	(c)	70
3	118	Statement of Retained Earnings	(c)	29
4	118	Statement of Retained Earnings	(c)	36
5	204,206	Electric Plant in Service	(g)	8-14,18-24,27-34,37-43, 50
6	204,206	Electric Plant in Service	(g)	4,86-59
7	206	Electric Plant in Service	(g)	97
8	219	Accumulated Provision for Depreciation	(c)	1
9	227	Materials and Supplies	(c)	1-2
10	227	Materials and Supplies	(c)	12,16
11	234	Accumulated Deferred Income Taxes (Account 190)	(c)	2
12	262	Taxes Accrued, Prepaid and Charged During the Year	(d)	17
13	262	Taxes Accrued, Prepaid and Charged During the Year	(d)	2,9
14	262	Taxes Accrued, Prepaid and Charged During the Year	(d)	3,4,10
15	266	Accumulated Deferred Investment Credits	(f)	8
16	275	Accumulated Deferred Income Taxes (Account 282)	(k)	2
17	277	Accumulated Deferred Income Taxes (Account 283)	(k)	3
18	320-321	Electric Operations and Maintenance Expense	(b)	4,6-11,15-19,24,26-32,35-39,44-49,53-57,62,64-66 and 69-72
19	320-321	Electric Operations and Maintenance Expense	(b)	93,107
20	323	Electric Operations and Maintenance Expense	(b)	181-184 and 186-193
21	323	Electric Operations and Maintenance Expense	(b)	185
22	326	Depreciation Expense	(f)	2-7
23	326	Depreciation Expense	(f)	10
24	110-111	Comparative Balance Sheet	(c)	48,52,54
25	110-111	Comparative Balance Sheet	(c)	57

26	114	Statement of Income	(c)	14
27	206-207	Electric Plant in Service	(g)	58
28	206-207	Electric Plant in Service	(g)	75
29	219	Accumulated Provision for Depreciation (Acc 108)	(c)	26
30	219	Accumulated Provision for Depreciation (Acc 108)	(c)	28
31	262-263	Taxes Accrued, Prepaid and Charged During the Year	(d)	3,4,10
32	262-263	Taxes Accrued, Prepaid and Charged During the Year	(d), (i)	14,18
33	274-277	Accumulated Deferred Income Taxes	(k)	9
34	274-277	Accumulated Deferred Income Taxes	(k)	19
35	300	Electric Operating Revenues	(b)	19
36	322	Electric Operations and Maintenance Expense	(b)	156
37	323	Electric Operations and Maintenance Expense	(b)	197
38	336	Depreciation and Amortization of Electric Plant	(f)	8
39	336	Depreciation and Amortization of Electric Plant	(f)	2-6
40	354	Distribution of Salaries and Wages	(b)	20
41	354	Distribution of Salaries and Wages	(b)	21
42	354	Distribution of Salaries and Wages	(b)	23
43	354	Distribution of Salaries and Wages	(b)	24-25
44	355	Distribution of Salaries and Wages	(b)	96

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: PageNumberOfFormulaRateVariances

Line No.	Page No(s)	Schedule	Column	Line No.
All	All	The following footnotes relate to RS No.705, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT)and/or the AECC Wholesale Distribution Formula Rate (WDS)		
1	111	Comparative Balance Sheet Prepayments used in UPS/DPPT, differs from Form 1 amounts because the formula rate reflects an allocation of the balance at the last day of the previous month, allocated using plant ratios	(c)	57
2	117	Statement of Income for the Year Interest expense used in UPS/DPPT, differs from Form 1 amounts because the formula rate reflects the embedded cost of debt at the last day of the previous month times the Debt Capitalization ratio at the last day of the previous month	(c)	70
3	118	Statement of Retained Earnings Return on Preferred Stock used in UPS/DPPT and, differs from Form 1 amounts because the formula rates calculate Return on Preferred Stock using the embedded cost of Preferred Stock at the last day of the previous month/year times the Preferred Stock Capitalization ratio at the last day of the previous month	(d)	29
4	118	Statement of Retained Earnings Return on Common Equity used in UPS/DPPT and WDS, differs from Form 1 amounts because the formula rate calculates Return on Common Equity using a stated Return on Equity of 11.0% for UPS/DPPT and the most recently approved retail rate of 9.75% for WDS times the Common Stock Capitalization ratio at the last day of the previous year	(c) (d)	36
5,6	204, 206	Electric Plant in Service Plant investment used in UPS/DPPT differs from Form 1 amounts because the formula rate only reflects the cost of the Designated Generating Unit, plus the cost of step-up transformers and associated transmission equipment related to the Designated Generating Unit, at the last day of the previous month	(b)(g)	8-14, 18-24, 27-34, 37-43 and 50
7	204, 206	Electric Plant in Service Plant investment used in UPS/DPPT differs from Form 1 amounts because the formula rate reflects an allocation of Misc. Intangible and General Plant investment at the last day of the previous month using a Labor Ratio	(b)	4, 86-95
8	206	Electric Plant in Service Plant investment used in UPS/DPPT differs from Form 1 amounts because the formula rate includes a direct assignment of the cost of any coal mining equipment associated with the Designated Generating Unit at the last day of the previous month	(b)	97
9	219	Accumulated Provision for Depreciation APD used in UPS/DPPT differs from Form 1 amounts because the formula rate only reflects the APD related to the Designated Generating Unit at the last day of the previous month based on wholesale depreciation rates	(b)	1
10	227	Materials and Supplies-Fuel Inventory Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the Fuel Inventory related to the Designated Generating Unit at the last day of the previous month	(c)	1-2
11	227	Materials and Supplies Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the Materials and Supplies related to the Designated Generating Unit at the last day of the previous month	(c)	12, 16
12	234	Accumulated Deferred Income Taxes(Account 190) Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate either directly assigns any ADIT related to the Designated Generating Unit or allocates ADIT based on a Plant Ratio including applicable adjustments associated with the Amortization of Protected & Unprotected Excess Deferred Income Taxes	(c)	2
13	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate allocates Corporate Franchise Taxes based on a Plant Ratio	(d)	18
14	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the ad valorem taxes related to the Designated Generating Unit	(d)	17
15	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rates calculate State and Federal income taxes using the incremental statutory rate	(d)	2, 9
16	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate allocates Payroll Taxes based on a Labor Ratio	(d)	3, 4, 10
17	266	Accumulated Deferred Investment Tax Credits Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate either directly assigns any ITC Amortization related to the Designated Generating Unit or allocates ITC Amortization based on a Plant Ratio	(f)	8
18	275	Accumulated Deferred Income Taxes (Account 282) Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate either directly assigns any ADIT related to the Designated Generating Unit or allocates ADIT based on a Plant Ratio including applicable adjustments associated with the Amortization of Protected & Unprotected Excess Deferred Income Taxes	(k)	2

19	277	Accumulated Deferred Income Taxes (Account 283) Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate either directly assigns any ADIT related to the Designated Generating Unit or allocates ADIT based on a Plant Ratio including applicable adjustments associated with the Amortization of Protected & Unprotected Excess Deferred Income Taxes	(k)	3
20, 21, 22	320-321	Electric Operations and Maintenance Expense Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the non-fuel Production O&M Expenses related to the Designated Generating Unit	(b)	4, 6-11, 15-19, 24, 26-32, 35-39, 44-49, 53-57, 62, 64-66 and 69-72
23	321	Electric Operations and Maintenance Expense Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the Transmission O&M Expenses related to the step-up transformers and associated transmission equipment related to the Designated Generating Unit	(c)	93, 107
24	323	Electric Operations and Maintenance Expenses Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate allocate A&G costs using a Labor Ratio	(c)	181-184 and 186-193
25	323	Electric Operations and Maintenance Expense Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the Insurance Expense related to the Designated Generating Unit	(c)	185
26	336	Depreciation Expense Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the monthly Depreciation Expense related to the Designated Generating Unit, plus the Depreciation Expense for the step-up transformers and associated transmission equipment related to the Designated Generating Unit based on Wholesale depreciation rates	(f)	2-7
27	336	Depreciation Expense Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects an allocation of the monthly General Plant Depreciation Expense using a Labor Ratio based on Wholesale depreciation rates	(f)	10
28	110-111	Comparative Balance Sheet The Materials and Supplies balance used in the WDS differs from the Form 1 amounts because formula rate uses the 13 month average of the balance	(c)	48, 52, 54
29	110-111	Comparative Balance Sheet The Prepayments balance used in the WDS differs from the Form 1 amounts because formula rate uses the 13 month average of the prepaid taxes and insurance balance excluding retail regulatory commission fees and expenses	(c)	57
30	114	Statement of Income Taxes Other than Income used in the WDS differ from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(c)	14
31	206 - 207	Electric Plant in Service Transmission Plant in Service in the WDS differs from Form 1 amounts because the formula rate adjusts for regional Transmission market labor, IPP prepayments (AFUDC capitalized) and non-retail specifically assigned Transmission Plant in Service	(g)	58
32	206 - 207	Electric Plant in Service Distribution Plant in Service in the WDS differs from Form 1 amounts because the formula rate adjusts for non-retail specifically assigned Distribution Plant in Service	(g)	75
33	206-207	Electric Plant in Service Distribution Plant in Service in the WDS differs from Form 1 amounts because the formula rate directly assigns the distribution Plant in Service balance to be customer specific (EAI to AECC)	(g)	75
34	206-207	Electric Plant in Service Distribution Plant in Service in the WDS differs from Form 1 amounts because the formula rate allocates a portion of the total plant in service to Wholesale	(g)	75
35	219	Accumulated Provision for Depreciation (Account 108) Distribution Accumulated Depreciation in the WDS differs from Form 1 amounts because the formula rate directly assigns the distribution Plant in Service balance to be customer specific (EAI to AECC) based on Wholesale depreciation rates	(b)	26
36	219	Accumulated Provision for Depreciation (Account 108) Distribution Accumulated Depreciation in the WDS differs from Form 1 amounts because the formula rate allocates a portion of the total accumulated depreciation to Wholesale based on Wholesale depreciation rates	(b)	26
37	219	Accumulated Provision for Depreciation (Account 108) General Accumulated Depreciation in the WDS differs from Form 1 amounts because the formula rate adjusts for the timing difference related to the FERC approved increase to non-production depreciate rates	(b)	28
38	262-263	Taxes Accrued, Prepaid and Charged During Year Base payroll related tax expense in the WDS differs from Form 1 amounts because the formula rate adjusted employment taxes (Acct 408110) for regulatory deferrals	(d)	7
39	262-263	Taxes Accrued, Prepaid and Charged During Year Retail related Taxes Other than Income Taxes in the WDS differs from Form 1 amounts because the formula rate includes Non-Income Tax - City Occupation Tax	(d), (i)	14, 18
40	274-277	Accumulated Deferred Income Taxes ADIT in the WDS differs from Form 1 amounts because the formula rate reduces the balance for any amounts associated with non-retail allocation of any plant in service amount for which the retail portion has been securitized and other amounts not included for cost-of-service purposes	(k)	9
41	274-277	Accumulated Deferred Income Taxes ADIT in the WDS differs from Form 1 amounts because the formula rate allocates a portion of the total accumulated depreciation to Wholesale	(k)	9
42	300	Electric Operating Revenues Distribution Related Revenue in the WDS differs from Form 1 amounts because the formula rate only includes revenues from distribution - rent from electric property and pole attachments rent.	(b)	19
43	300	Electric Operating Revenues General Plant Related Revenue in the WDS differs from Form 1 amounts because the formula rate only includes revenues from general plant - rent from electric property.	(b)	19
44	322	Electric Operation and Maintenance Expenses Total Distribution Expense (Accts 580 – 598) in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	156
45	323	Electric Operation and Maintenance Expenses Total A&G Expense (Accts 920 – 935) in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	197
46	336	Depreciation and Amortization of Electric Plant Total Distribution Depreciation Expense in the WDS differs from Form 1 amounts because the formula rate adjusts for non-retail specifically assigned distribution plant in service	(f)	8
47	336	Depreciation and Amortization of Electric Plant Total Distribution Depreciation Expense in the WDS differs from Form 1 amounts because the formula rate allocates a portion of the total accumulated depreciation to Wholesale	(f)	8
48	336	Depreciation and Amortization of Electric Plant Total Other Production Plant Depreciation Expense in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(f)	10
49	354	Distribution of Salaries and Wages Production Labor in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	20
50	354	Distribution of Salaries and Wages Transmission Labor in the WDS differs from Form 1 amounts because the formula rate adjusts for regional Transmission market labor and regulatory deferrals	(b)	21
51	354	Distribution of Salaries and Wages Distribution Labor in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	23

52	354	Distribution of Salaries and Wages Customer Accounts, Customer Service and Informational Labor in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	24-25
53	355	Distribution of Salaries and Wages Total Labor (including Nuclear and Non-Nuclear affiliate) in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	96

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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. None

2. None

3. None

4. None

5. None

6. See Entergy Arkansas's 2025 FERC Form 1 Notes to Financial Statements, Notes 4, 5 and 8.

7. None

8. Fossil operating and clerical employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Unions 647 and 750. The Company and the Union agreed to a contract effective October 1, 2021 through August 31, 2025. The Company and the Union agreed to a new contract effective September 1, 2025 through August 31, 2030. Effective September 1, 2025, the wages had a one-time market adjustment of 1.0% with a general wage increase of 4.0%.

Transmission, distribution, and utility support employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Unions 647, 750, 1439, and 1703. The Company and the Union agreed to a contract effective October 1, 2024 through September 30, 2029. Effective October 1, 2025, the wages had a one-time market adjustment of 1.0% with a general wage increase of 3.0%.

Effective April 1, 2025, executive and senior management, middle management, professionals, and non-represented operating, maintenance, and support staff pay increases averaged approximately 3.5%.

Arkansas Nuclear One
Operating, maintenance, engineering, technical, and administrative employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Union 647. The Company and the Union agreed to a contract effective March 1, 2024 through February 28, 2029. Effective January 1, 2025, the wages had a one-time market adjustment of 1.0% with a general wage increase of 3.0%.

Security employees are represented by the United Government Security Officers of America, Local Union 23. The Company and the Union agreed to a contract effective March 1, 2022 through February 28, 2026. Effective March 1, 2025, the wage increase was 2.0%.

9. See Entergy Arkansas's 2025 FERC Form 1 Notes to Financial Statements, Notes 2 and 8.

10. None

12. See Entergy Arkansas's 2025 FERC Form 1 Notes to Financial Statements.

13. See Entergy Arkansas's 2025 FERC Form 1 pages 104 and 105 for Officer and Director changes that occurred in 2025.

14. Not applicable

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	17,042,884,849	16,358,151,254
3	Construction Work in Progress (107)	200	623,032,579	351,159,739
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		17,665,917,428	16,709,310,993
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	6,301,385,359	6,029,137,756
6	Net Utility Plant (Enter Total of line 4 less 5)		11,364,532,069	10,680,173,237
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	80,103,751	86,203,515
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	
10	Spent Nuclear Fuel (120.4)		0	
11	Nuclear Fuel Under Capital Leases (120.6)		210,769,093	165,658,030
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	(11,832,996)	(5,671,495)
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		302,705,840	257,533,040
14	Net Utility Plant (Enter Total of lines 6 and 13)		11,667,237,909	10,937,706,277
15	Utility Plant Adjustments (116)		0	
16	Gas Stored Underground - Noncurrent (117)		0	
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		917,564	917,564
19	(Less) Accum. Prov. for Depr. and Amort. (122)		142,000	137,999
20	Investments in Associated Companies (123)		0	
21	Investment in Subsidiary Companies (123.1)	224	81,176,708	84,350,954
23	Noncurrent Portion of Allowances and Environmental Credits	228	0	
24	Other Investments (124)		0	
25	Sinking Funds (125)		0	
26	Depreciation Fund (126)		0	
27	Amortization Fund - Federal (127)		0	
28	Other Special Funds (128)		1,816,348,028	1,604,445,864
29	Special Funds (Non Major Only) (129)		0	
30	Long-Term Portion of Derivative Assets (175)		0	
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,898,300,300	1,689,576,383

33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	
35	Cash (131)		6,095,420	431,911
36	Special Deposits (132-134)		36,977,207	
37	Working Fund (135)		0	(10)
38	Temporary Cash Investments (136)		265,713,446	
39	Notes Receivable (141)		0	
40	Customer Accounts Receivable (142)		164,296,000	139,233,930
41	Other Accounts Receivable (143)		87,029,397	70,927,126
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,302,586	4,671,956
43	Notes Receivable from Associated Companies (145)		0	
44	Accounts Receivable from Assoc. Companies (146)		100,968,613	35,771,251
45	Fuel Stock (151)	227	26,483,949	34,264,667
46	Fuel Stock Expenses Undistributed (152)	227	12,898,284	15,671,999
47	Residuals (Elec) and Extracted Products (153)	227	0	
48	Plant Materials and Operating Supplies (154)	227	399,734,542	350,426,134
49	Merchandise (155)	227	0	
50	Other Materials and Supplies (156)	227	0	
51	Nuclear Materials Held for Sale (157)	202/227	0	
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228	7	20
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228	0	
54	Stores Expense Undistributed (163)	227	30,927,347	33,811,939
55	Gas Stored Underground - Current (164.1)		0	
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	
57	Prepayments (165)		18,499,772	13,139,862
58	Advances for Gas (166-167)		0	
59	Interest and Dividends Receivable (171)		861,281	27,101
60	Rents Receivable (172)		0	
61	Accrued Utility Revenues (173)		130,950,083	125,824,094
62	Miscellaneous Current and Accrued Assets (174)		37,786,521	56,224,442
63	Derivative Instrument Assets (175)		5,503,567	8,579,526
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	
65	Derivative Instrument Assets - Hedges (176)		0	
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	
67	Total Current and Accrued Assets (Lines 34 through 66)		1,317,422,850	879,662,036
68	DEFERRED DEBITS			

69	<u>Unamortized Debt Expenses (181)</u>		42,148,132	42,303,473
70	<u>Extraordinary Property Losses (182.1)</u>	230a	0	
71	<u>Unrecovered Plant and Regulatory Study Costs (182.2)</u>	230b	29,222,398	32,764,506
72	<u>Other Regulatory Assets (182.3)</u>	232	1,417,723,385	1,394,573,800
73	<u>Prelim. Survey and Investigation Charges (Electric) (183)</u>		3,459,097	12,803,178
74	<u>Preliminary Natural Gas Survey and Investigation Charges 183.1)</u>		0	
75	<u>Other Preliminary Survey and Investigation Charges (183.2)</u>		0	
76	<u>Clearing Accounts (184)</u>		(114,213)	(47,554)
77	<u>Temporary Facilities (185)</u>		0	
78	<u>Miscellaneous Deferred Debits (186)</u>	233	205,336,715	154,255,711
79	<u>Def. Losses from Disposition of Utility Plt. (187)</u>		0	
80	<u>Research, Devel. and Demonstration Expend. (188)</u>	352	0	
81	<u>Unamortized Loss on Reaquired Debt (189)</u>		17,385,039	18,617,324
82	<u>Accumulated Deferred Income Taxes (190)</u>	234	513,524,908	470,475,382
83	<u>Unrecovered Purchased Gas Costs (191)</u>		0	
84	<u>Total Deferred Debits (lines 69 through 83)</u>		2,228,685,461	2,125,745,820
85	<u>TOTAL ASSETS (lines 14-16, 32, 67, and 84)</u>		17,111,646,520	15,632,690,516

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: NuclearFuelUnderCapitalLeases

FUEL LEASE FOR ARKANSAS NUCLEAR ONE
LESSOR: RIVER FUEL TRUST #1

Investment of River Fuel Trust #1 at December 31, 2025	
Investment at December 31, 2024	\$165,658,030
Additional investment in fuel	129,928,850
Daily lease charges allocated to and included in capitalized costs	1,560,014
Less: Burn-up charges paid to lessor	86,377,801
Total Investment at December 31, 2025	\$210,769,093
Cost Incurred under River Fuel Trust#1 Lease for the Year Ended December 31, 2025	
Daily Lease Charges	\$4,900,277

(b) Concept: NuclearFuelUnderCapitalLeases

As of December 31, 2025, arrangements to lease nuclear fuel existed in an aggregate amount up to \$240 million for Entergy Arkansas. The lessors finance the acquisition and ownership of nuclear fuel through loans made under revolving credit agreements, the issuance of commercial paper, and the issuance of intermediate-term notes. The credit agreements for Entergy Arkansas have a termination date of June 25, 2027. The intermediate-term notes issued pursuant to these fuel lease arrangements have varying maturities through May 1, 2029. It is expected that additional financing under the leases will be arranged as needed to acquire additional fuel, to pay interest, and to pay maturing debt. However, if such additional financing cannot be arranged, the lessee in each case must repurchase sufficient nuclear fuel to allow the lessor to meet its obligations in accordance with the fuel lease.

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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	0	
3	Preferred Stock Issued (204)	250	0	
4	Capital Stock Subscribed (202, 205)		0	
5	Stock Liability for Conversion (203, 206)		0	
6	Premium on Capital Stock (207)		0	
7	Other Paid-In Capital (208-211)	253	1,928,477,357	1,928,477,357
8	Installments Received on Capital Stock (212)	252	0	
9	(Less) Discount on Capital Stock (213)	254	0	
10	(Less) Capital Stock Expense (214)	254b	0	
11	Retained Earnings (215, 215.1, 216)	118	2,767,931,526	2,517,191,158
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(1,653,465)	(1,445,092)
13	(Less) Reacquired Capital Stock (217)	250	0	
14	Noncorporate Proprietorship (Non-major only) (218)		0	
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	
16	Total Proprietary Capital (lines 2 through 15)		4,694,755,418	4,444,223,423
17	LONG-TERM DEBT			
18	Bonds (221)	256	5,060,000,000	4,760,000,000
19	(Less) Reacquired Bonds (222)	256	0	
20	Advances from Associated Companies (223)	256	0	
21	Other Long-Term Debt (224)	256	227,196,607	217,925,957
22	Unamortized Premium on Long-Term Debt (225)		15,329,503	15,736,689
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		11,306,366	12,116,869
24	Total Long-Term Debt (lines 18 through 23)		5,291,219,744	4,981,545,777
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		214,236,697	167,830,746
27	Accumulated Provision for Property Insurance (228.1)		78,376,577	70,604,344
28	Accumulated Provision for Injuries and Damages (228.2)		6,458,566	5,170,649
29	Accumulated Provision for Pensions and Benefits (228.3)		7,798,611	6,934,483
30	Accumulated Miscellaneous Operating Provisions (228.4)		704,000	704,000
31	Accumulated Provision for Rate Refunds (229)		0	

32	Long-Term Portion of Derivative Instrument Liabilities		0	
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	
34	Asset Retirement Obligations (230)		1,791,372,043	1,691,583,008
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,098,946,494	1,942,827,230
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	
38	Accounts Payable (232)		346,316,707	207,921,179
39	Notes Payable to Associated Companies (233)		0	
40	Accounts Payable to Associated Companies (234)		124,373,179	104,711,178
41	Customer Deposits (235)		136,586,561	129,266,776
42	Taxes Accrued (236)	262	390,043,047	152,477,057
43	Interest Accrued (237)		47,799,235	45,331,237
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)		0	
46	Matured Interest (240)		0	
47	Tax Collections Payable (241)		17,985,308	17,332,359
48	Miscellaneous Current and Accrued Liabilities (242)		7,436,825	10,152,879
49	Obligations Under Capital Leases-Current (243)		109,042,589	98,842,683
50	Derivative Instrument Liabilities (244)		0	
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	
52	Derivative Instrument Liabilities - Hedges (245)		0	
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,179,583,451	766,035,348
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		218,791,656	165,738,541
57	Accumulated Deferred Investment Tax Credits (255)	266	24,867,892	26,069,176
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	2,784,786	23,308,606
60	Other Regulatory Liabilities (254)	278	1,521,421,961	1,387,411,668
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,891,098,509	1,696,233,154
64	Accum. Deferred Income Taxes-Other (283)		188,176,609	199,297,593
65	Total Deferred Credits (lines 56 through 64)		3,847,141,413	3,498,058,738
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		17,111,646,520	15,632,690,516

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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

Do not report fourth quarter data in columns (e) and (f)
 Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
 Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
 Use page 122 for important notes regarding the statement of income for any account thereof.
 Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be 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 affected 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.
 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.
 If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
 Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
 Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
 If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to 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 Utility 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	<u>UTILITY OPERATING INCOME</u>											
2	<u>Operating Revenues (400)</u>	300	2,775,524,224	2,454,245,250			2,775,524,224	2,454,245,250				
3	<u>Operating Expenses</u>											
4	<u>Operation Expenses (401)</u>	320	1,135,487,569	1,071,224,036			1,135,487,569	1,071,224,036				
5	<u>Maintenance Expenses (402)</u>	320	271,669,621	226,448,986			271,669,621	226,448,986				
6	<u>Depreciation Expense (403)</u>	336	451,409,667	354,220,216			451,409,667	354,220,216				
7	<u>Depreciation Expense for Asset Retirement Costs (403.1)</u>	336	12,105,089	11,195,861			12,105,089	11,195,861				
8	<u>Amort. & Depl. of Utility Plant (404-405)</u>	336	155,145	55,140,917			155,145	55,140,917				
9	<u>Amort. of Utility Plant Acq. Adj. (406)</u>	336	2,501,807	2,501,807			2,501,807	2,501,807				
10	<u>Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)</u>		3,542,109	3,542,109			3,542,109	3,542,109				
11	<u>Amort. of Conversion Expenses (407.2)</u>											
12	<u>Regulatory Debits (407.3)</u>		23,245,753	69,471,737			23,245,753	69,471,737				
13	<u>(Less) Regulatory Credits (407.4)</u>		91,963,696	230,832,166			91,963,696	230,832,166				
14	<u>Taxes Other Than Income Taxes (408.1)</u>	262	162,231,509	139,481,214			162,231,509	139,481,214				
15	<u>Income Taxes - Federal (409.1)</u>	262	(24,264,976)	(18,971,163)			(24,264,976)	(18,971,163)				

75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262	0									
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		440,531,995	324,766,014								

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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		2,517,191,158	2,501,689,901
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)		440,740,368	325,501,257
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Common equity distributions	131	(190,000,000)	(310,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(190,000,000)	(310,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,767,931,526	2,517,191,158
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)		2,767,931,526	2,517,191,158
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			

49	Balance-Beginning of Year (Debit or Credit)		(1,445,092)	(709,849)
50	Equity in Earnings for Year (Credit) (Account 418.1)		(208,373)	(735,243)
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)		(1,653,465)	(1,445,092)

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	<u>Net Cash Flow from Operating Activities</u>		
2	<u>Net Income (Line 78(c) on page 117)</u>	440,531,995	324,766,014
3	<u>Noncash Charges (Credits) to Income:</u>		
4	<u>Depreciation and Depletion</u>	570,415,288	520,183,021
5	<u>Amortization of (Specify) (footnote details)</u>		
5.1	<u>Amortization of debt discount and expense and premium on debt and amortization of loss on reacquired debt</u>	5,452,971	5,187,059
8	<u>Deferred Income Taxes (Net)</u>	128,482,192	113,390,671
9	<u>Investment Tax Credit Adjustment (Net)</u>	(1,230,547)	(1,230,443)
10	<u>Net (Increase) Decrease in Receivables</u>	(87,141,849)	114,576,522
11	<u>Net (Increase) Decrease in Inventory</u>	(35,869,383)	(18,377,207)
12	<u>Net (Increase) Decrease in Allowances and Environmental Credits Inventory</u>	13	47
13	<u>Net Increase (Decrease) in Payables and Accrued Expenses</u>	411,666,298	(55,346,090)
14	<u>Net (Increase) Decrease in Other Regulatory Assets</u>	(23,149,585)	169,804,047
15	<u>Net Increase (Decrease) in Other Regulatory Liabilities</u>	134,010,293	70,956,943
16	<u>(Less) Allowance for Other Funds Used During Construction</u>	24,348,988	29,569,362
17	<u>(Less) Undistributed Earnings from Subsidiary Companies</u>		
18	<u>Other (provide details in footnote):</u>		
18.1	<u>Other Working Capital</u>	(16,400,737)	5,332,383
18.2	<u>Other</u>	(309,774,665)	(317,415,652)
22	<u>Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)</u>	1,192,643,296	902,257,953
24	<u>Cash Flows from Investment Activities:</u>		
25	<u>Construction and Acquisition of Plant (including land):</u>		
26	<u>Gross Additions to Utility Plant (less nuclear fuel)</u>	(1,046,878,493)	(812,325,301)
27	<u>Gross Additions to Nuclear Fuel</u>	(120,818,805)	(151,603,757)
28	<u>Gross Additions to Common Utility Plant</u>		
29	<u>Gross Additions to Nonutility Plant</u>		
30	<u>(Less) Allowance for Other Funds Used During Construction</u>	(24,348,988)	(29,569,362)

31	Other (provide details in footnote):		
31.1	Decommissioning Trust Funds	(33,281,051)	(12,494,857)
31.2	Proceeds from Sale of Nuclear Fuel	170,523,955	127,096,311
31.3	Payment for purchase of plant and assets	(3,516,742)	(819,013,978)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,009,622,148)	(1,638,772,220)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies	2,965,874	2,639,610
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Changes in money pool receivable - net	(21,715,213)	
53.2	Other	(35,862,576)	29,664
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,064,234,063)	(1,636,102,946)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	299,109,158	789,728,607
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Capital contribution from parent		695,000,000
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	299,109,158	1,484,728,607
72	Payments for Retirement of:		
73	Long-term Debt (b)		(375,021,284)
74	Preferred Stock		

75	<u>Common Stock</u>		
76	<u>Other (provide details in footnote):</u>		
76.1	<u>Other</u>	49,049,073	64,383,014
76.2	<u>Common equity distributions paid</u>	(190,000,000)	(310,000,000)
76.3	<u>Changes in money pool payable - net</u>	(15,190,499)	(130,195,000)
78	<u>Net Decrease in Short-Term Debt (c)</u>		
80	<u>Dividends on Preferred Stock</u>		
81	<u>Dividends on Common Stock</u>		
83	<u>Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)</u>	142,967,732	733,895,337
85	<u>Net Increase (Decrease) in Cash and Cash Equivalents</u>		
86	<u>Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)</u>	271,376,965	50,344
88	<u>Cash and Cash Equivalents at Beginning of Period</u>	431,901	381,557
90	<u>Cash and Cash Equivalents at End of Period</u>	271,808,866	431,901

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Other investing activities include:

	<u>2025</u>	<u>2024</u>	
Independent System Operator Special Deposit - Hot Springs	(\$36,977,207)		\$—
Proceeds from sale of land	1,063,756		—
Transformer asset transfer	50,875		—
Third party sales reimbursement fee	—		29,664
Total	(\$35,862,576)		\$29,664

(b) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Other financing activities include:

	<u>2025</u>	<u>2024</u>	
Customer Advances for Construction	\$53,053,115		\$69,612,961
Financing Leases	(3,981,847)		(5,229,947)
Little Rock Air Force Base debt reduction	(22,195)		—
Total	\$49,049,073		\$64,383,014

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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, where 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.

A. CASH FLOW STATEMENT, ADDITIONAL INFORMATION:

Cash and Cash Equivalents at December 31, 2025	
Cash (Account 131)	\$6,095,420
Temporary Cash Investments (Account 136)	265,713,446
Total	\$271,808,866
Supplemental Disclosure of Cash Flow Statement	
Cash paid (received) during the period for:	(in 000s)
Interest - net of amount capitalized	\$213,561
Income Taxes - net (includes production tax credit sales proceeds of \$215,224)	(\$244,911)

B. FERC FORM 1 PRESENTATION COMPARED TO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and accounting releases, which differs from GAAP. Additional comparative data, including the 2023 data for the statement of income, retained earnings and cash flows, are needed to present the financial position and results of operations in order to satisfy GAAP. In addition, GAAP requires the disclosure of the current and long-term portion of assets and liabilities. In accordance with FERC reporting requirements, the aforementioned disclosures were not included in these financial statements.

As required by the FERC, Entergy Arkansas classifies certain items in the income statement (primarily the classification of operating expenses and other deductions) and in the balance sheet (primarily the classification of the components of accumulated deferred income taxes, taxes accrued, certain other miscellaneous current and accrued liabilities, maturities of long-term debt, deferred debits, deferred credits, plant in service, and accumulated depreciation) in a manner different than that required by GAAP.

GAAP requires Entergy Arkansas to consolidate the company from which it leases nuclear fuel, whereas this company is not consolidated for the FERC Form 1 presentation. The significant difference that results from this is the elimination from the GAAP balance sheet of the obligations under capital leases with the nuclear fuel companies and the addition to the GAAP balance sheet of the nuclear fuel companies' credit facility borrowings, commercial paper, and notes payable.

Finally, GAAP requires that Entergy Arkansas consolidate AR Searcy Partnership, LLC, due to the significant influence it exerts as the managing member of the partnership, whereas Entergy Arkansas's investment in the partnership is presented in the FERC Form 1 as an equity-method investment. Additionally, GAAP requires Entergy Arkansas to record the earnings it receives from the partnership using the hypothetical-liquidation at book value (HLBV) method of accounting because the limited liability agreement forming the partnership stipulates a disproportionate allocation of tax attributes, earnings, and cash flows between Entergy Arkansas and the other investor in the partnership. In contrast, Entergy Arkansas recognizes its share in the partnership earnings based on its ownership-percentage in the partnership for reporting in the FERC Form 1.

C. Entergy Arkansas implemented FERC Order 898 effective January 1, 2025. The balance sheet as of December 31, 2025 reflects transfers with plant balances and the associated accumulated depreciation. Refer to FERC Form 1 page 219 for details on transfers.

D. The Notes to the Financial Statements included herein are adapted from the Entergy Corporation and subsidiaries Form 10-K for the Year Ended December 31, 2025. The Form 10-K Notes to the Financial Statements are prepared in conformity with GAAP, and thus may differ in certain instances from the financial statements contained herein.

"Entergy" when used in these Notes means Entergy Corporation and its direct and indirect subsidiaries.

"Registrant Subsidiaries" when used in these Notes means Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, Entergy Texas, Inc., and System Energy Resources, Inc.

"Utility" when used in the Notes means Entergy's business segment that generates, transmits, distributes, and sells electric power.

"Utility operating companies" when used in these Notes means Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates in the Preparation of Financial Statements

In conformity with GAAP in the United States of America, the preparation of Entergy Corporation's consolidated financial statements and the separate financial statements of the Registrant Subsidiaries requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities. Adjustments to the reported amounts of assets and liabilities may be necessary in the future to the extent that future estimates or actual results are different from the estimates used.

Customer Advances

Certain large industrial customers are required by Entergy's Regulators to make advance payments in excess of what would typically be required under existing utility rates to offset the costs the Utility operating companies will incur to serve the customer. The Utility operating companies will be required to include the revenue related to these additional payments in ratemaking in future periods to offset the costs of serving the customer that made the payment. In some cases, the advance payment is designed to provide the Utility operating companies with a return on construction work in progress for utility plant investments typically received through the recognition of AFUDC (as defined and described further below). In such cases, AFUDC is not added to the associated construction work in progress, which results in a lower amount of utility plant recovered through utility rates. Customer advances are initially recorded as a current or non-current liability and then recognized as revenue as the related costs are incurred.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Depreciation is computed on the straight-line basis at rates based on the applicable estimated service lives of the various classes of property. For the Registrant Subsidiaries, the original cost of plant retired or removed, less salvage, is charged to accumulated depreciation. Normal maintenance, repairs, and minor replacement costs are charged to operating expenses. Certain combined cycle gas turbine generating units are maintained under long-term service agreements with third-party service providers. The costs under these agreements are split between operating expenses and capital additions based upon the nature of the work performed. Substantially all of the Registrant Subsidiaries' plant is subject to mortgage liens.

Customers may be required to make advance payments to reimburse the Utility operating companies for costs of constructing new utility plants that are not expected to be recovered through existing retail rates. Under the regulatory framework, these payments are required to ensure the cost to serve a particular customer does not increase the utility rates charged to other utility customers. These advance payments generally do not reduce the retail rate charged to the customer making the payment and do not create any additional obligation for the respective Utility operating company to provide electrical service beyond the general obligation to serve all customers in its service area. Because the cost is fully reimbursed by the customer through the advance payment, the Utility operating company does not earn a return or recover through retail rates the cost of utility plant reimbursed by these payments. These advance payments are initially recorded as a non-current liability, which is then reduced by the costs incurred to construct the associated utility plant. This results in Entergy and the Utility operating companies recording utility plant funded by customer advances at a net cost of zero, consistent with utility ratemaking treatment.

Details of property, plant, and equipment by functional category are presented on FERC Form 1 pages 204-207 and details of accumulated depreciation by functional category are presented on FERC Form 1 page 219.

Depreciation rates on average depreciable property for the Registrant Subsidiaries are shown below:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
2025	2.8%	2.7%	3.4%	3.3%	3.6%	2.1%
2024	2.7%	2.7%	3.5%	3.3%	3.8%	2.1%
2023	2.7%	2.6%	3.6%	3.3%	4.0%	1.6%

Jointly-Owned Generating Stations

Certain Entergy subsidiaries jointly own electric generating facilities with affiliates or third parties. All parties are required to provide their own financing. The investments, fuel expenses, and other operation and maintenance expenses associated with these generating stations are recorded by the Entergy subsidiaries to the extent of their respective undivided ownership interests. As of December 31, 2025, the subsidiaries' investment and accumulated depreciation in each of these generating stations were as follows:

Generating Stations	Fuel Type	Total Megawatt Capability (a)	Ownership	Investment	Accumulated Depreciation	
(In Millions)						
Utility:						
Entergy Arkansas -						
Independence	Unit 1	Coal	824	31.50%	\$153	\$110
Independence	Common Facilities	Coal		15.75%	\$43	\$33
White Bluff	Units 1 and 2	Coal	1,253	57.00%	\$624	\$424
Ouachita (b)	Common Facilities	Gas		66.67%	\$174	\$162
Union (c)	Common Facilities	Gas		25.00%	\$29	\$15
Entergy Louisiana -						
Roy S. Nelson	Unit 6	Coal	514	40.25%	\$302	\$237
Roy S. Nelson	Unit 6 Common Facilities	Coal		40.25%	\$22	\$11
Big Cajun 2	Unit 3	Coal	551	24.15%	\$146	\$142
Big Cajun 2	Unit 3 Common Facilities	Coal		8.05%	\$5	\$3
Ouachita (b)	Common Facilities	Gas		33.33%	\$91	\$80
Acadia	Common Facilities	Gas		50.00%	\$22	\$4
Union (c)	Common Facilities	Gas		50.00%	\$58	\$17
Entergy Mississippi -						
Independence	Units 1 and 2 and Common Facilities	Coal	1,666	25.00%	\$307	\$204
Entergy New Orleans -						
Union (c)	Common Facilities	Gas		25.00%	\$30	\$12
Entergy Texas -						
Roy S. Nelson	Unit 6	Coal	514	29.75%	\$213	\$178
Roy S. Nelson	Unit 6 Common Facilities	Coal		29.75%	\$8	\$5
Big Cajun 2	Unit 3	Coal	551	17.85%	\$109	\$129
Big Cajun 2	Unit 3 Common Facilities	Coal		5.95%	\$4	\$3
Montgomery County	Unit 1	Gas	940	92.44%	\$761	\$54
System Energy -						
Grand Gulf	Unit 1	Nuclear	1,397	90.00%	\$5,763	\$3,681
Other:						
Independence	Unit 2	Coal	842	14.37%	\$82	\$63
Independence	Common Facilities	Coal		7.18%	\$21	\$17
Roy S. Nelson	Unit 6	Coal	514	10.90%	\$121	\$79
Roy S. Nelson	Unit 6 Common Facilities	Coal		10.90%	\$3	\$2

- "Total Megawatt Capability" is the dependable summer load carrying capability as demonstrated under actual operating conditions based on the primary fuel (assuming no curtailments) that each station was designed to utilize.
- Ouachita Units 1 and 2 are owned 100% by Entergy Arkansas and Ouachita Unit 3 is owned 100% by Entergy Louisiana. The investment and accumulated depreciation numbers above are only for the common facilities and not for the generating units.
- Union Unit 1 is owned 100% by Entergy New Orleans, Union Unit 2 is owned 100% by Entergy Arkansas, Union Units 3 and 4 are owned 100% by Entergy Louisiana. The investment and accumulated depreciation numbers above are only for the specified common facilities and not for the generating units.

Nuclear Refueling Outage Costs

Nuclear refueling outage costs are deferred during the outage and amortized over the estimated period to the next outage because these refueling outage expenses are incurred to prepare the units to operate for the next operating cycle without having to be taken off line.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction by the Registrant Subsidiaries. AFUDC increases both the plant balance and earnings and is realized in cash through depreciation provisions included in the rates charged to customers.

Income Taxes

Entergy Corporation and the majority of its subsidiaries file a United States consolidated federal income tax return. Each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the tax filing entities in accordance with the Entergy Tax Allocation Agreement. Deferred income taxes are recorded for temporary differences between the book and tax basis of assets and liabilities, and for certain losses and credits available for carryforward.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates in the period in which the tax or rate was enacted.

The benefits of investment tax credits are deferred and amortized over the average useful life of the related property, as a reduction of income tax expense, for such credits associated with rate-regulated operations in accordance with ratemaking treatment.

Accounting for the Effects of Regulation

Entergy's Utility operating companies and System Energy are rate-regulated entities that are required to reflect the effects of rate regulation in their financial statements, including the recording of regulatory assets and liabilities, as the Utility operating companies and System Energy have rates that meet the following three criteria: (1) are approved by a third-party regulator; (2) are designed to recover the entities' cost of providing the regulated services or products; and (3) can reasonably be assumed will be charged to and collected from customers. These criteria may also be applied to separable portions of a utility's business, such as the generation or transmission functions, or to specific classes of customers.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery from customers through regulated rates. Regulatory liabilities represent (1) revenue or gains that have been deferred because it is probable such amounts will be credited to customers through future regulated rates, (2) billings in advance of expenditures for approved regulatory programs, or (3) refunds ordered by regulators. To the extent that all or portions of the Utility operating companies or System Energy's operations cease to be subject to rate regulation, or future recovery or settlement is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are eliminated from the balance sheet and the impact is recognized on the income statement.

In addition, regulatory accounting requires recognition of an impairment loss if it becomes probable that part of the cost of a recently completed plant asset will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made.

Regulatory Asset or Liability for Income Taxes

Accounting standards for income taxes provide that a regulatory asset or liability be recorded if it is probable that the currently determinable future increase or decrease in regulatory income tax expense will be recovered from or credited to customers through future rates. There are two main sources of Entergy's regulatory asset or liability for income taxes. There is a regulatory asset related to the ratemaking treatment of the tax effects of book depreciation for the equity component of AFUDC that has been capitalized to property, plant, and equipment but for which there is no corresponding tax basis. Equity-AFUDC is a component of property, plant, and equipment that is included in rate base when the plant is placed in service. There is a regulatory liability related to the adjustment of Entergy's net deferred income taxes that was required by the enactment in December 2017 of a change in the federal corporate income tax rate, which is discussed in Note 3 to the financial statements.

Cash and Cash Equivalents

Entergy considers all unrestricted highly liquid debt instruments with an original maturity of three months or less at date of purchase to be cash equivalents.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects Entergy's best estimate of expected losses on its accounts receivable balances. The allowance is calculated as the historical rate of customer write-offs multiplied by the current accounts receivable balance, taking into account the length of time the receivable balances have been outstanding. Although the rate of customer write-offs has historically experienced minimal variation, management monitors the current condition of individual customer accounts and general economic conditions to manage collections and ensure bad debt expense is recorded in a timely manner. The Utility operating companies' customer accounts receivable are written off consistent with approved regulatory requirements.

Materials and Supplies

Materials and supplies consist of tangible goods, equipment, and other materials that Entergy holds for use or consumption in the normal course of business, whether for capital projects or operation and maintenance activities, or that are required to be kept for regulatory reasons or service reliability. Materials and supplies are valued at a weighted average unit cost when expensed or capitalized, as appropriate, when used or installed. Materials and supplies are valued at the lower of weighted average cost or net realizable value, net of provisions for surplus and obsolete materials and supplies.

Investments

Entergy records decommissioning trust funds on the balance sheet at their fair value. Because of the ability of the Registrant Subsidiaries to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, for unrealized gains/(losses) on investment securities, the Registrant Subsidiaries record an offsetting amount in other regulatory liabilities/assets. Entergy's trusts are managed by third parties who operate in accordance with agreements that define investment guidelines and place restrictions on the purchases and sales of investments. See Note 16 to the financial statements for details on the decommissioning trust funds.

Derivative Financial Instruments and Commodity Derivatives

The accounting standards for derivative instruments require that all derivatives be recognized at fair value on the balance sheet, either as assets or liabilities, unless they meet various exceptions including the normal purchase/normal sale criteria. The changes in the fair value of recognized derivatives are recorded each period in current earnings. Due to regulatory treatment, an offsetting regulatory asset or liability is recorded for changes in fair value of recognized derivatives for the Registrant Subsidiaries.

Contracts for commodities that will be physically delivered in quantities expected to be used or sold in the ordinary course of business, including certain purchases and sales of power and fuel, meet the normal purchase, normal sales criteria and are not recognized on the balance sheet. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Entergy has determined that contracts to purchase uranium do not meet the definition of a derivative under the accounting standards for derivative instruments because they do not provide for net settlement and the uranium markets are not sufficiently liquid to conclude that forward contracts are readily convertible to cash. If the uranium markets do become sufficiently liquid in the future and Entergy begins to account for uranium purchase contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Entergy's other derivative instruments. See Note 15 to the financial statements for further details on Entergy's derivative instruments and hedging activities.

Fair Values

The estimated fair values of Entergy's financial instruments and derivatives are determined using historical prices, bid prices, market quotes, and financial modeling. Considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that Entergy could realize in a current market exchange. Gains or losses realized on financial instruments are reflected in future rates and therefore do not affect net income. Entergy considers the carrying amounts of most financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. See Note 15 to the financial statements for further discussion of fair value.

Impairment of Long-lived Assets

Entergy periodically reviews long-lived assets whenever events or changes in circumstances indicate that recoverability of these assets is uncertain. Generally, the determination of recoverability is based on the undiscounted net cash flows expected to result from such operations and assets. Projected net cash flows depend on the expected operating life of the assets, the future operating costs associated with the assets, the efficiency and availability of the assets and generating units, and the future market and price for energy and capacity over the remaining life of the assets.

Reacquired Debt

The premiums and costs associated with reacquired debt of Entergy's Utility operating companies and System Energy are being amortized over the life of the related new issuances, or over the life of the original debt issuance if the debt is not refinanced, in accordance with ratemaking treatment.

Taxes Imposed on Revenue-Producing Transactions

Governmental authorities assess taxes that are both imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer, including, but not limited to, sales, use, value added, and some excise taxes. Entergy presents these taxes on a net basis, excluding them from revenues, unless required to report them differently by a regulatory authority.

NOTE 2. RATE AND REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent probably future revenues associated with costs that are expected to be recovered from customers through the regulatory ratemaking process under which the Utility business operates. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to benefit customers through the regulatory ratemaking process under which the Utility business operates. Details of regulatory assets in FERC account 182.3 are presented on FERC Form 1 page 232. Details of regulatory liabilities in FERC account 254 are presented on FERC Form 1 page 278.

Fuel and purchased power cost recovery

The Utility operating companies are allowed to recover fuel and purchased power costs through fuel mechanisms included in electric and gas rates that are recorded as fuel cost recovery revenues. The difference between revenues collected and the current fuel and purchased power costs is generally recorded as "Deferred fuel costs" on the Utility operating companies' financial statements. The table below shows the amount of current deferred fuel costs as of December 31, 2025 and 2024 that each Utility operating company expects to recover (or return to customers) through fuel mechanisms, subject to subsequent regulatory review.

	2025	2024
	(In Millions)	
Entergy Arkansas	\$27.7	(\$45.2)
Entergy Louisiana	\$15.7	(\$4.7)
Entergy Mississippi	\$10.8	(\$126.3)
Entergy New Orleans	(\$3.2)	\$3.9
Entergy Texas	(\$11.4)	(\$59.3)

In addition, Entergy Louisiana and Entergy New Orleans have \$168.1 million and \$4.1 million, respectively, classified as long-term deferred fuel costs for fuel, purchased power, and capacity costs, which do not currently earn a return on investment and whose recovery periods are indeterminate but are expected to be recovered over a period greater than twelve months, on their consolidated balance sheets as of December 31, 2025 and 2024.

Entergy Arkansas

Energy Cost Recovery Rider

Entergy Arkansas's retail rates include an energy cost recovery rider to recover fuel and purchased energy costs in monthly customer bills. The rider utilizes the prior calendar-year energy costs and projected energy sales for the twelve-month period commencing on April 1 of each year to develop an energy cost rate, which is redetermined annually and includes a true-up adjustment reflecting the over- or under-recovery, including carrying charges, of the energy costs for the prior calendar year. The energy cost recovery rider tariff also allows an interim rate request depending upon the level of over- or under-recovery of fuel and purchased energy costs.

In January 2014, Entergy Arkansas filed a motion with the APSC relating to its upcoming energy cost rate redetermination filing that was made in March 2014. In that motion, Entergy Arkansas requested that the APSC authorize Entergy Arkansas to exclude from the redetermination of its 2014 energy cost rate \$65.9 million of incremental fuel and replacement energy costs incurred in 2013 as a result of the ANO stator incident. Entergy Arkansas requested that the APSC authorize Entergy Arkansas to retain that amount in its deferred fuel balance, with recovery to be reviewed in a later period after more information was available regarding various claims associated with the ANO stator incident. In February 2014 the APSC approved Entergy Arkansas's request to retain that amount in its deferred fuel balance. In July 2017, Entergy Arkansas filed for a change in rates pursuant to its formula rate plan rider. In that proceeding, the APSC approved a settlement agreement agreed upon by the parties, including a provision that requires Entergy Arkansas to initiate a regulatory proceeding for the purpose of recovering funds currently withheld from rates and related to the stator incident, including the \$65.9 million of deferred fuel and purchased energy costs and costs related to the incremental oversight previously noted, subject to certain timelines and conditions set forth in the settlement agreement. In October 2023, Entergy Arkansas made a commitment to the APSC to make a filing to forgo its opportunity to seek recovery of the incremental fuel and purchased energy expense, among other identified costs, resulting from the ANO stator incident. As a result, in third quarter 2023, Entergy Arkansas recorded a write-off of its regulatory asset for deferred fuel of \$68.9 million, which includes interest, related to the ANO stator incident. Consistent with its October 2023 commitment, Entergy Arkansas filed a motion to forgo recovery in November 2023, and the motion was approved by the APSC in December 2023. See the "[ANO Damage, Outage, and NRC Reviews](#)" section in Note 8 to the financial statements for further discussion of the ANO stator incident and the approved motion to forgo recovery.

In March 2017, Entergy Arkansas filed its annual redetermination of its energy cost rate pursuant to the energy cost recovery rider, which reflected an increase in the rate from \$0.01164 per kWh to \$0.01547 per kWh. The APSC staff filed testimony in March 2017 recommending that the redetermined rate be implemented with the first billing cycle of April 2017 under the normal operation of the tariff. Accordingly, the redetermined rate went into effect on March 31, 2017 pursuant to the tariff. In July 2017 the Arkansas Attorney General requested additional information to support certain of the costs included in Entergy Arkansas's 2017 energy cost rate redetermination.

In March 2018, Entergy Arkansas filed its annual redetermination of its energy cost rate pursuant to the energy cost recovery rider, which reflected an increase in the rate from \$0.01547 per kWh to \$0.01882 per kWh. The Arkansas Attorney General filed a response to Entergy Arkansas's annual redetermination filing requesting that the APSC suspend the proposed tariff to investigate the amount of the redetermination or, alternatively, to allow recovery subject to refund. Among the reasons the Attorney General cited for suspension were questions pertaining to how Entergy Arkansas forecasted sales and potential implications of the Tax Cuts and Jobs Act. Entergy Arkansas replied to the Attorney General's filing and stated that, to the extent there are questions pertaining to its load forecasting or the operation of the energy cost recovery rider, those issues exceed the scope of the instant rate redetermination. Entergy Arkansas also stated that potential effects of the Tax Cuts and Jobs Act are appropriately considered in the APSC's separate proceeding regarding potential implications of the tax law. The APSC general staff filed a reply to the Attorney General's filing and agreed that Entergy Arkansas's filing complied with the terms of the energy cost recovery rider. The redetermined rate became effective with the first billing cycle of April 2018. Subsequently in April 2018 the APSC issued an order declining to suspend Entergy Arkansas's energy cost recovery rider rate and declining to require further investigation at that time of the issues suggested by the Attorney General in the proceeding. Following a period of discovery, the Attorney General filed a supplemental response in October 2018 raising new issues with Entergy Arkansas's March 2018 rate redetermination and asserting that \$45.7 million of the increase should be collected subject to refund pending further investigation. Entergy Arkansas filed to dismiss the Attorney General's supplemental response, the APSC general staff filed a motion to strike the Attorney General's filing, and the Attorney General filed a supplemental response disputing Entergy Arkansas and the APSC staff's filing. Applicable APSC rules and processes authorize its general staff to initiate periodic audits of Entergy Arkansas's energy cost recovery rider. In late-2018 the APSC general staff notified Entergy Arkansas it initiated an audit of the 2017 fuel costs. The timing of the audit's completion is uncertain at this time.

In March 2023, Entergy Arkansas filed its annual redetermination of its energy cost rate pursuant to the energy cost recovery rider, which reflected an increase in the rate from \$0.01639 per kWh to \$0.01883 per kWh. The primary reason for the rate increase was a large under-recovered balance as a result of higher natural gas prices in 2022 and a \$32 million deferral related to the APSC general staff's request in 2022 for Entergy Arkansas to defer its request for recovery related to the February 2021 winter storms until the 2023 energy cost rate redetermination. In February 2023 the APSC issued orders initiating proceedings to address the prudence of costs incurred and appropriate cost allocation of the February 2021 winter storms, and in September 2023 the APSC issued an order finding Entergy Arkansas's practices during the February 2021 winter storms to be prudent. The under-recovered balance included in the March 2023 filing was partially offset by the proceeds of the \$41.7 million refund that System Energy made to Entergy Arkansas in January 2023 related to the sale-leaseback renewal costs and depreciation litigation as calculated in System Energy's January 2023 compliance report filed with the FERC. See "[Complaints Against System Energy - Grand Gulf Sale-leaseback Renewal Complaint and Uncertain Tax Position Rate Base Issue](#)" below for discussion of the compliance report filed by System Energy with the FERC in January 2023. The redetermined rate of \$0.01883 per kWh became effective with the first billing cycle in April 2023 through the normal operation of the tariff.

In March 2024, Entergy Arkansas filed its annual redetermination of its energy cost rate pursuant to the energy cost recovery rider, which reflected a decrease in the rate from \$0.01883 per kWh to \$0.00882 per kWh. Due to a change in law in the State of Arkansas, the annual redetermination included \$9 million, recorded as a credit to fuel expense in first quarter 2024, for recovery attributed to net metering costs in 2023. The primary reason for the rate decrease was a large over-recovered balance as a result of lower natural gas prices in 2023. To mitigate the effect of projected increases in natural gas prices in 2024, Entergy Arkansas adjusted the over-recovered balance included in the March 2024 annual redetermination filing by \$43.7 million. This adjustment reduced the rate change that was reflected in the 2025 energy cost rate redetermination. The redetermined rate of \$0.00882 per kWh became effective with the first billing cycle in April 2024 through the normal operation of the tariff.

In March 2025, Entergy Arkansas filed its annual redetermination of its energy cost rate pursuant to the energy cost recovery rider, which reflected an increase in the rate from \$0.00882 per kWh to \$0.01333 per kWh. The annual redetermination included a credit related to the remaining balance due to retail customers from the System Energy settlement with the APSC, plus carrying charges and interest. See "[Retail Rate Proceedings - Filings with the APSC \(Entergy Arkansas\) - Retail Rates - Grand Gulf Credit Rider](#)" below for further discussion. The primary reason for the rate increase was an adjustment to account for projected increases in natural gas prices in 2025. This adjustment is expected to reduce the rate change that will be reflected in Entergy Arkansas's 2026 energy cost rate redetermination. The redetermined rate of \$0.01333 per kWh became effective with the first billing cycle in April 2025 through the normal operation of the tariff.

Retail Rate Proceedings

Filings with the APSC (Entergy Arkansas)

Retail Rates

2023 Formula Rate Plan Filing

In July 2023, Entergy Arkansas filed with the APSC its 2023 formula rate plan filing to set its formula rate for the 2024 calendar year. The filing contained an evaluation of Entergy Arkansas's earnings for the projected year 2024 and a netting adjustment for the historical year 2022. The filing showed that Entergy Arkansas's earned rate of return on common equity for the 2024 projected year was 8.11% resulting in a revenue deficiency of \$80.5 million. The earned rate of return on common equity for the 2022 historical year was 7.29% resulting in a \$49.8 million netting adjustment. The total proposed revenue change for the 2024 projected year and 2022 historical year netting adjustment was \$130.3 million. By operation of the formula rate plan, Entergy Arkansas's recovery of the revenue requirement is subject to a four percent annual revenue constraint. Because Entergy Arkansas's revenue requirement in this filing exceeded the constraint, the resulting increase was limited to \$88.6 million. The APSC general staff and intervenors filed their errors and objections report in October 2023, proposing certain adjustments, including the APSC general staff's update to annual filing year revenues which lowers the constraint to \$87.7 million. In October 2023, Entergy Arkansas filed with the APSC a settlement agreement reached with other parties involving all issues in the proceeding, none of which affected Entergy Arkansas's requested recovery up to the constraint of \$87.7 million. The settlement agreement provided for amortization of the approximately \$39 million regulatory asset for costs associated with the COVID-19 pandemic over a 10-year period as well as recovery of \$34.9 million related to the resolution of the 2016 and 2017 IRS audits from previous tax positions that are no longer uncertain, partially offset by \$24.7 million in excess accumulated deferred income taxes from reductions in state income tax rates, each before consideration of their respective tax gross-up. See Note 3 to the financial statements for further discussion of the resolution of the 2016-2018 IRS audit and the State of Arkansas corporate income tax rate changes. In December 2023 the APSC approved the settlement agreement as being in the public interest and approved Entergy Arkansas's compliance tariff effective with the first billing cycle of January 2024.

2024 Formula Rate Plan Filing

In July 2024, Entergy Arkansas filed with the APSC its 2024 formula rate plan filing to set its formula rate for the 2025 calendar year. The filing contained an evaluation of Entergy Arkansas's earnings for the 2025 projected year and a netting adjustment for the 2023 historical year. The filing showed that Entergy Arkansas's earned rate of return on common equity for the 2025 projected year was 8.43% resulting in a revenue deficiency of \$69.5 million. The earned rate of return on common equity for the 2023 historical year was 7.48% resulting in a \$33.1 million netting adjustment. The total proposed revenue change for the 2025 projected year and 2023 historical year netting adjustment was \$102.6 million. By operation of the formula rate plan, Entergy Arkansas's recovery of the revenue requirement is subject to a four percent annual revenue constraint. Because Entergy Arkansas's revenue requirement in this filing exceeded the constraint, the resulting increase was limited to \$82.6 million. The APSC general staff and intervenors filed their errors and objections report in October 2024, proposing certain adjustments, including the APSC general staff's update to annual filing year revenues that increases the constraint to \$83.5 million. Entergy Arkansas filed its rebuttal in October 2024, and later in October 2024 the parties submitted a joint issues list and stipulations setting forth the disputed issues and the noncontested issues. In December 2024 the APSC approved the parties' stipulations without modification, approved Entergy Arkansas's adjustment with respect to storm costs, directed Entergy Arkansas to adjust its projected year distribution reliability capital closings, and deferred the recoverability of Entergy Arkansas's opportunity sales legal fees until the next general rate case. Also in December 2024 the APSC approved Entergy Arkansas's compliance tariff effective with the first billing cycle of January 2025. As a result of the proceeding, the total revenue change was \$82.7 million, including a \$63.7 million increase for the 2025 projected year and a \$31.4 million netting adjustment for the 2023 historical year. In fourth quarter 2024, Entergy Arkansas recorded a regulatory asset of \$15.5 million to reflect the amount of the 2023 historical year netting adjustment that it collected from its customers during the 2025 rate effective period. Pursuant to the terms of the parties' stipulations, Entergy Arkansas made a filing with the APSC in January 2025 to refund customers \$30.1 million in excess accumulated deferred income taxes resulting from the reduction in the State of Arkansas's income tax rate from 4.8% to 4.3% in 2024. Entergy Arkansas began refunding this amount over a 24-month period effective with the first billing cycle of February 2025.

2025 Formula Rate Plan Filing

In July 2025, Entergy Arkansas filed with the APSC its 2025 formula rate plan filing to set its formula rate for the 2026 calendar year. The filing contained an evaluation of Entergy Arkansas's earnings for the 2026 projected year and a netting adjustment for the 2024 historical year. The filing showed that Entergy Arkansas's earned rate of return on common equity for the 2026 projected year was 8.45% resulting in a revenue deficiency of \$68.9 million. The earned rate of return on common equity for the 2024 historical year was 7.71% resulting in a \$48.8 million netting adjustment. The total proposed revenue change for the 2026 projected year and 2024 historical year netting adjustment was \$117.7 million. By operation of the formula rate plan, Entergy Arkansas's recovery of the revenue requirement is subject to a four percent annual revenue constraint. Because Entergy Arkansas's revenue requirement in this filing exceeded the constraint, the resulting increase was limited to \$92.3 million. The APSC general staff filed their errors and objections report in October 2025, proposing an adjustment to the coupon rate for the projected long-term debt issuance in 2026 and an update to annual filing year revenues that increases the constraint to \$93.9 million. Entergy Arkansas filed its rebuttal in October 2025. A hearing was scheduled for November 2025, and an order was expected in December 2025. Due to no contested issues remaining outstanding among the parties to the proceeding, in October 2025, Entergy Arkansas and the APSC general staff filed a joint motion requesting the APSC cancel the hearing and issue a decision based on the pleadings and testimony in the record. The APSC granted this request. In December 2025 the APSC approved Entergy Arkansas's request as modified by the APSC general staff's errors and objections report and Entergy Arkansas's rebuttal testimony. Also in December 2025 the APSC approved Entergy Arkansas's compliance tariff effective with the first billing cycle of January 2026. As a result of the proceeding, the total revenue change was \$93.9 million, including a \$65.6 million increase for the 2026 projected year and a \$48.8 million netting adjustment for the 2024 historical year. In fourth quarter 2025, Entergy Arkansas recorded a regulatory asset of \$28.3 million to reflect the amount of the 2024 historical year netting adjustment that it expects to collect from its customers during the 2026 rate effective period.

Grand Gulf Credit Rider

In June 2024, Entergy Arkansas filed with the APSC a tariff to provide retail customers a credit resulting from the terms of the settlement agreement between Entergy Arkansas, System Energy, additional named Entergy parties, and the APSC pertaining to System Energy's billings for wholesale sales of energy and capacity from the Grand Gulf nuclear plant. See "[Complaints Against System Energy - System Energy Settlement with the APSC](#)" below for discussion of the System Energy settlement with the APSC. In July 2024 the APSC approved the tariff, under which Entergy Arkansas would refund to retail customers a total of \$100.6 million. Entergy Arkansas refunded \$92.3 million of the total through one-time bill credits under the Grand Gulf credit rider during the August 2024 billing cycle. In March 2025, Entergy Arkansas included the remaining balance as a credit to retail customers in its energy cost recovery rider rate reetermination filing. See further discussion within "[Regulatory Assets and Regulatory Liabilities - Fuel and purchased power cost recovery - Entergy Arkansas](#) - Energy Cost Recovery Rider" above. In April 2025 the APSC approved Entergy Arkansas's proposal to include the remaining balance in its energy cost recovery rider effective with the first billing cycle of April 2025 and the withdrawal of the Grand Gulf credit rider after all credits had been issued. Credits to retail customers were completed in second quarter 2025, and the Grand Gulf credit rider was subsequently withdrawn.

Generating Arkansas Jobs Act Rider

In March 2025 the State of Arkansas passed the Generating Arkansas Jobs Act of 2025, now Act 373 (Act 373), that authorizes the recovery of financing costs during construction of generation and transmission investments through a rider separate from the formula rate plan. Act 373 also permits cost recovery of those investments, when completed and in service, either through the next general rate case proceeding or under the formula rate plan. Act 373 streamlines and simplifies the regulatory approval process and provides increased timeliness and certainty of cost recovery.

In July 2025, Entergy Arkansas submitted a tariff filing with the APSC requesting approval of a strategic investment recovery rider, consistent with the provisions of Act 373. In October 2025 the APSC issued an order approving the proposed rider with several revisions, including elimination of an annual true-up adjustment, a change in cost allocation methodology, the removal of excess and deficient accumulated deferred income taxes to a separate rider, and the addition of reporting requirements. As directed by the order, in October 2025, Entergy Arkansas made a compliance filing. In November 2025, the APSC general staff recommended additional updates to the compliance filing, including limiting the accumulated deferred income tax adjustment to excess accumulated deferred income taxes. Also, in November 2025, Entergy Arkansas filed a second compliance filing, which was approved by the APSC.

Special Rate Contract and Arkansas Cypress Solar

In September 2025, Entergy Arkansas filed an application with the APSC seeking approval of a long-term special rate contract between Altitude, LLC, a subsidiary of Alphabet, Inc. (Google) and Entergy Arkansas for the sale of electricity to a new large-scale data center in West Memphis, Arkansas. In October 2025 the APSC general staff filed testimony finding that based on its evaluation of Entergy Arkansas's application and the results of the ratepayer impact measure test, the special rate contract meets the requirements of the APSC's promotional practice rules and is in the public interest. No other parties filed testimony. In December 2025 the APSC issued an order approving the special rate contract but denying the requested ratemaking treatment of Google's upfront payments and deferring a decision on the treatment under the contract pricing providing for the deferral and amortization of the investment tax credits from the Arkansas Cypress Solar facility (discussed below). Also in December 2025, Entergy Arkansas filed a petition with the APSC regarding these findings, noting that they would require renegotiation of the special rate contract. In January 2026 the APSC issued an order maintaining its position on the ratemaking treatment of Google's upfront payments but reversing itself on the treatment of the Arkansas Cypress Solar facility investment tax credits and allowing those to be used in the pricing of the Arkansas Cypress Solar facility to Google as provided for in the contract.

In September 2025, Entergy Arkansas filed an application with the APSC seeking a certificate of environmental compatibility and public need for the construction and operation of the Arkansas Cypress Solar facility, a planned 600 MW solar photovoltaic array with a 350 MW battery energy storage system and associated transmission facilities interconnecting at Entergy Arkansas's White Bluff substation. The estimated cost of the project is \$1,602 million. Entergy Arkansas is seeking public interest and prudence findings from the APSC no later than 180 days from the filing, pursuant to Act 373 of 2025, to construct the Arkansas Cypress Solar facility in support of its long-term special rate contract with Google. In October 2025 the APSC general staff and the Arkansas Attorney General filed responsive testimony opposing the project cost and seeking additional information. Subsequently, the APSC general staff submitted supplemental testimony to update its initial conclusion and recommendations, noting that the Arkansas Cypress Solar facility is a reasonable project and recommending the APSC approve the project under certain conditions. Entergy Arkansas proposes to recover the costs of constructing the Arkansas Cypress Solar facility through the Generating Arkansas Jobs Act rider. A hearing was held in December 2025, and an APSC decision is due in March 2026. Subject to receipt of required regulatory approval and other conditions, the facility is expected to be in service by the end of 2028. See "[Generating Arkansas Jobs Act Rider](#)" above for discussion of the Generating Jobs Act rider, which was approved by the APSC in October 2025.

Entergy Arkansas Opportunity Sales Proceeding

In June 2009 the LPSC filed a complaint requesting that the FERC determine that certain of Entergy Arkansas's sales of electric energy to third parties: (a) violated the provisions of the System Agreement that allocated the energy generated by Entergy System resources; (b) imprudently denied the Entergy System and its ultimate consumers the benefits of low-cost Entergy System generating capacity; and (c) violated the provision of the System Agreement that prohibited sales to third parties by individual companies absent an offer of a right-of-first-refusal to other Utility operating companies. The LPSC's complaint challenged sales made beginning in 2002 and requested refunds. In July 2009 the Utility operating companies filed a response to the complaint arguing among other things that the System Agreement contemplated that the Utility operating companies may make sales to third parties for their own account, subject to the requirement that those sales be included in the load (or load shape) for the applicable Utility operating company. The FERC subsequently ordered a hearing in the proceeding.

The FERC issued a decision in June 2012 and held that, while the System Agreement was ambiguous, it did provide authority for individual Utility operating companies to make opportunity sales for their own account and Entergy Arkansas made and priced these sales in good faith. The FERC found, however, that the System Agreement did not provide authority for an individual Utility operating company to allocate the energy associated with such opportunity sales as part of its load but provides a different allocation authority. The FERC further found that the after-the-fact accounting methodology used to allocate the energy used to supply the sales was inconsistent with the System Agreement. The FERC in its decision established further hearing procedures to quantify the effect of repricing the opportunity sales in accordance with the FERC's June 2012 decision. The hearing was held in May 2013 and the ALJ issued an initial decision in August 2013.

In April 2016 the FERC issued orders addressing requests for rehearing filed in July 2012 and the ALJ's August 2013 initial decision. The first order denied Entergy's request for rehearing and affirmed the FERC's earlier rulings that Entergy's original methodology for allocating energy costs to the opportunity sales was incorrect and, as a result, Entergy Arkansas must make payments to the other Utility operating companies to put them in the same position that they would have been in absent the incorrect allocation. The FERC clarified that interest should be included with the payments. The second order affirmed in part, and reversed in part, the rulings in the ALJ's August 2013 initial decision regarding the methodology that should be used to calculate the payments Entergy Arkansas is to make to the other Utility operating companies. The FERC affirmed the ALJ's ruling that a full re-run of intra-system bills should be performed but required that methodology be modified so that the sales have the same priority for purposes of energy allocation as joint account sales. The FERC reversed the ALJ's decision that any payments by Entergy Arkansas should be reduced by 20%. The FERC also reversed the ALJ's decision that adjustments to other System Agreement service schedules and excess bandwidth payments should not be taken into account when calculating the payments to be made by Entergy Arkansas. The FERC held that such adjustments and excess bandwidth payments should be taken into account but ordered further proceedings before an ALJ to address whether a cap on any reduction due to bandwidth payments was necessary and to implement the other adjustments to the calculation methodology.

The hearing required by the FERC's second April 2016 order was held in May 2017. In July 2017 the ALJ issued an initial decision addressing whether a cap on any reduction due to bandwidth payments was necessary and whether to implement the other adjustments to the calculation methodology. In August 2017 the Utility operating companies, the LPSC, the APSC, and FERC staff filed individual briefs on exceptions challenging various aspects of the initial decision. In September 2017 the Utility operating companies, the LPSC, the APSC, the MPSC, the City Council, and FERC staff filed separate briefs opposing exceptions taken by various parties.

Based on testimony previously submitted in the case and its assessment of the April 2016 FERC orders, in the first quarter 2016, Entergy Arkansas recorded a liability of \$87 million, which included interest, for its estimated increased costs and payment to the other Utility operating companies, and a deferred fuel regulatory asset of \$75 million. Following its assessment of the course of the proceedings, including the FERC's denial of rehearing in November 2017 described above, in the fourth quarter 2017, Entergy Arkansas recorded an additional liability of \$35 million and a regulatory asset of \$31 million.

In October 2018 the FERC issued an order addressing the ALJ's July 2017 initial decision. The FERC reversed the ALJ's decision to cap the reduction in Entergy Arkansas's payment to account for the increased bandwidth payments that Entergy Arkansas made to the other operating companies. The FERC also reversed the ALJ's decision that Grand Gulf sales from January through September 2000 should be included in the calculation of Entergy Arkansas's payment. The FERC affirmed on other grounds the ALJ's rejection of the LPSC's claim that certain joint account sales should be accounted for as part of the calculation of Entergy Arkansas's payment. In November 2018 the LPSC requested rehearing of the FERC's October 2018 decision. In December 2019 the FERC denied the LPSC's request for rehearing.

In December 2018, Entergy made a compliance filing in response to the FERC's October 2018 order. The compliance filing provided a final calculation of Entergy Arkansas's payments to the other Utility operating companies, including interest. Refunds and interest, totaling \$135 million, were paid by Entergy Arkansas to the other operating companies in December 2018.

Entergy Arkansas previously recognized a regulatory asset with a balance of \$116 million as of December 31, 2018 for a portion of the payments due as a result of this proceeding.

The FERC's opportunity sales orders were appealed to the D.C. Circuit. In February 2020 all of the appeals were consolidated and in April 2020 the D.C. Circuit established a briefing schedule. Briefing was completed in September 2020 and oral argument was heard in December 2020. In July 2021 the D.C. Circuit issued a decision denying all of the petitions for review filed in response to the FERC's opportunity sales orders.

In May 2019, Entergy Arkansas filed an application and supporting testimony with the APSC requesting approval of a special rider tariff to recover the costs of these payments from its retail customers over a 24-month period. In January 2020 the Attorney General and Arkansas Electric Energy Consumers, Inc. filed testimony opposing the recovery by Entergy Arkansas of the opportunity sales payment but also claiming that certain components of the payment should be segregated and refunded to customers. In March 2020, Entergy Arkansas filed rebuttal testimony.

In July 2020 the APSC issued a decision finding that Entergy Arkansas's application is not in the public interest. The order also directed Entergy Arkansas to refund to its retail customers within 30 days of the order the FERC-determined over-collection of \$13.7 million, plus interest, associated with a recalculated bandwidth remedy. In addition to these primary findings, the order also denied the Attorney General's request for Entergy Arkansas to prepare a compliance filing detailing all of the retail impacts from the opportunity sales and denied a request by the Arkansas Electric Energy Consumers to recalculate all costs using the revised responsibility ratio. The refunds were issued in the August 2020 billing cycle. Entergy Arkansas believed its actions were prudent and, therefore, the costs, including the \$13.7 million, plus interest, were recoverable, and in September 2020, Entergy Arkansas filed a complaint in the U.S. District Court for the Eastern District of Arkansas challenging the APSC's order denying Entergy Arkansas's request to recover the costs of these payments.

In March 2024 the U.S. District Court for the Eastern District of Arkansas issued a judgment in favor of the APSC and against Entergy Arkansas. In March 2024 Entergy Arkansas filed a notice of appeal and a motion to expedite oral arguments with the United States Court of Appeals for the Eighth Circuit and the court granted the motion to expedite. Briefing to the United States Court of Appeals for the Eighth Circuit concluded in July 2024 and oral arguments concluded in September 2024. As a result of the adverse decision by the U.S. District Court for the Eastern District of Arkansas, Entergy Arkansas concluded that it could no longer support the recognition of its \$131.8 million regulatory asset reflecting the previously-expected recovery of a portion of the costs at issue in the opportunity sales proceeding and recorded a \$131.8 million (\$99.1 million net-of-tax) charge to earnings in first quarter 2024. In December 2024 the United States Court of Appeals for the Eighth Circuit affirmed the decision of the U.S. District Court for the Eastern District of Arkansas, and Entergy Arkansas filed a petition for rehearing *en banc*. In January 2025 the United States Court of Appeals for the Eighth Circuit denied Entergy Arkansas's petition. In April 2025, Entergy Arkansas filed a petition for certiorari with the United States Supreme Court. In June 2025 the United States Supreme Court denied Entergy Arkansas's petition for certiorari.

Federal Rate Proceedings

System Energy Settlement with the APSC

In October 2023, System Energy, Entergy Arkansas, and additional named Entergy parties involved in multiple docketed proceedings pending before the FERC reached a settlement in principle with the APSC to globally resolve all of their actual and potential claims in those dockets and with System Energy's past implementation of the Unit Power Sales Agreement. The settlement also covered the amended and supplemental complaint, discussed above in "[Grand Gulf Prudence Complaints](#)," filed at the FERC in October 2023. System Energy, Entergy Arkansas, additional Entergy parties, and the APSC filed the settlement agreement and supporting materials with the FERC in November 2023.

The terms of the settlement with the APSC aligned with the \$588 million global black box settlement reached between System Energy and the MPSC in June 2022 and provided for Entergy Arkansas to receive a black box refund of \$142 million from System Energy, inclusive of \$49.5 million already received by Entergy Arkansas from System Energy. In addition, beginning with the November 2023 service month, the settlement provided for Entergy Arkansas's bills from System Energy to be adjusted to reflect an authorized rate of return on equity of 9.65% and a capital structure not to exceed 52% equity through June 2026. In March 2024 the FERC approved the settlement, and System Energy paid the remaining black box refund of \$93 million to Entergy Arkansas in 2024.

MSS-4 Replacement Tariff – Net Operating Loss Carryforward Proceeding

In January 2021, pursuant to section 205 of the Federal Power Act, Entergy Services filed an amendment to the MSS-4 replacement tariff, a tariff governing the sales of energy and capacity among the Utility operating companies, in order to provide for the inclusion of specified accumulated deferred income taxes, including net operating loss carryforward accumulated deferred income taxes (NOLC ADIT), in the rate for sales of energy among the Utility operating companies on a prospective basis. In March 2021, the FERC accepted the filing, subject to refund and hearing procedures.

In October 2021 the LPSC filed a complaint with the FERC alleging that Entergy Services improperly excluded NOLC ADIT from MSS-4 replacement tariff rates in the period before March 20, 2021. The LPSC argued that sales from Entergy Louisiana to Entergy Texas and Entergy New Orleans were charged at rates lower than they otherwise should have been, and it accordingly seeks surcharges for the period prior to March 20, 2021. The FERC set the complaint for hearing procedures and subsequently the hearing for this complaint proceeding was consolidated with the hearing procedures for Entergy Services' January 2021 NOLC ADIT filing.

Testimony was filed by parties in 2023, and the hearing before a FERC ALJ was concluded in February 2024. In June 2024, the FERC ALJ issued an initial decision addressing three major issues: (1) whether Entergy Services' proposed prospective inclusion and allocation of NOLC ADIT in MSS-4 replacement tariff rates using a modified with-and-without methodology is just and reasonable; (2) whether Entergy Services correctly calculated excess and deficient accumulated deferred income taxes in accordance with the terms of a prior settlement; and (3) whether NOLC ADIT should have been included in MSS-4 replacement tariff rates prior to the effective date of the January 2021 MSS-4 replacement tariff filing.

With respect to issues (1) and (2), the presiding ALJ concluded that Entergy Services' proposed methodology for allocating and including NOLC ADIT in MSS-4 replacement tariff rates was just and reasonable and that Entergy Services correctly performed the excess and deficient accumulated deferred income taxes calculations. With respect to issue (3), however, the presiding ALJ agreed with the LPSC that NOLC ADIT should have been included in MSS-4 replacement tariff rates since September 1, 2016, and as a result, the presiding ALJ ordered that Entergy Louisiana and Entergy Arkansas recalculate bills for the period of September 1, 2016 through November 11, 2023 with surcharges expected to be due to those operating companies from the purchasing operating companies, Entergy New Orleans, Entergy Texas, and Entergy Louisiana (for some Entergy Arkansas sales). The presiding ALJ also ordered Entergy Services to pay the interest owed to Entergy Louisiana on these surcharges.

The surcharge methodology that the presiding ALJ recommended in connection with issue (3) was not supported by any participant in the hearing. As part of their exceptions to the initial decision, all parties to the proceeding opposed the use of the ALJ's methodology, except for the FERC trial staff, which took no position. During the hearing, the LPSC and the FERC trial staff advocated that the alleged tariff violation should be remedied by the application of Entergy Services' January 2021 proposed methodology. All other parties, including the PUCT, the City Council, and Entergy Services, opposed any surcharges for the period prior to the March 20, 2021 effective date of the January 2021 filing.

Entergy Services disputes the presiding ALJ's rulings on issue (3) and filed exceptions to these rulings in July 2024. The ALJ's initial decision is not binding on the FERC and is an interim step in the hearing process. No refunds will be owed in connection with this proceeding unless and until the FERC requires them in a final order.

The MSS-4 replacement tariff includes protocols that provide for the disclosure of cost inputs, an opportunity for informal discovery procedures, and a challenge process. In April 2025, pursuant to such protocols, the City Council filed with the FERC a formal challenge relating to Entergy Services' inclusion and allocation of net operating loss carryforward accumulated deferred income taxes in the MSS-4 replacement tariff rates charged to Entergy New Orleans's monthly bills for calendar year 2023. In May 2025, Entergy Services filed a response to the formal challenge and is awaiting a response from the FERC.

System Energy Settlement with the APSC

In October 2023, System Energy, Entergy Arkansas, and additional named Entergy parties involved in multiple docketed proceedings pending before the FERC reached a settlement in principle with the APSC to globally resolve all of their actual and potential claims in those dockets and with System Energy’s past implementation of the Unit Power Sales Agreement. The settlement also covered the amended and supplemental complaint, discussed above in “Grand Gulf Prudence Complaints,” filed at the FERC in October 2023. System Energy, Entergy Arkansas, additional Entergy parties, and the APSC filed the settlement agreement and supporting materials with the FERC in November 2023.

The terms of the settlement with the APSC aligned with the \$588 million global black box settlement reached between System Energy and the MPSC in June 2022 and provided for Entergy Arkansas to receive a black box refund of \$142 million from System Energy, inclusive of \$49.5 million already received by Entergy Arkansas from System Energy. In addition, beginning with the November 2023 service month, the settlement provided for Entergy Arkansas’s bills from System Energy to be adjusted to reflect an authorized rate of return on equity of 9.65% and a capital structure not to exceed 52% equity through June 2026. In March 2024 the FERC approved the settlement, and System Energy paid the remaining black box refund of \$93 million to Entergy Arkansas in 2024.

MSS-4 Replacement Tariff – Net Operating Loss Carryforward Proceeding

In January 2021, pursuant to section 205 of the Federal Power Act, Entergy Services filed an amendment to the MSS-4 replacement tariff, a tariff governing the sales of energy and capacity among the Utility operating companies, in order to provide for the inclusion of specified accumulated deferred income taxes, including net operating loss carryforward accumulated deferred income taxes (NOLC ADIT), in the rate for sales of energy among the Utility operating companies on a prospective basis. In March 2021, the FERC accepted the filing, subject to refund and hearing procedures.

In October 2021 the LPSC filed a complaint with the FERC alleging that Entergy Services improperly excluded NOLC ADIT from MSS-4 replacement tariff rates in the period before March 20, 2021. The LPSC argued that sales from Entergy Louisiana to Entergy Texas and Entergy New Orleans were charged at rates lower than they otherwise should have been, and it accordingly seeks surcharges for the period prior to March 20, 2021. The FERC set the complaint for hearing procedures and subsequently the hearing for this complaint proceeding was consolidated with the hearing procedures for Entergy Services’ January 2021 NOLC ADIT filing.

Testimony was filed by parties in 2023, and the hearing before a FERC ALJ was concluded in February 2024. In June 2024, the FERC ALJ issued an initial decision addressing three major issues: (1) whether Entergy Services’ proposed prospective inclusion and allocation of NOLC ADIT in MSS-4 replacement tariff rates using a modified with-and-without methodology is just and reasonable; (2) whether Entergy Services correctly calculated excess and deficient accumulated deferred income taxes in accordance with the terms of a prior settlement; and (3) whether NOLC ADIT should have been included in MSS-4 replacement tariff rates prior to the effective date of the January 2021 MSS-4 replacement tariff filing.

With respect to issues (1) and (2), the presiding ALJ concluded that Entergy Services’ proposed methodology for allocating and including NOLC ADIT in MSS-4 replacement tariff rates was just and reasonable and that Entergy Services correctly performed the excess and deficient accumulated deferred income taxes calculations. With respect to issue (3), however, the presiding ALJ agreed with the LPSC that NOLC ADIT should have been included in MSS-4 replacement tariff rates since September 1, 2016, and as a result, the presiding ALJ ordered that Entergy Louisiana and Entergy Arkansas recalculate bills for the period of September 1, 2016 through November 11, 2023 with surcharges expected to be due to those operating companies from the purchasing operating companies, Entergy New Orleans, Entergy Texas, and Entergy Louisiana (for some Entergy Arkansas sales). The presiding ALJ also ordered Entergy Services to pay the interest owed to Entergy Louisiana on these surcharges.

The surcharge methodology that the presiding ALJ recommended in connection with issue (3) was not supported by any participant in the hearing. As part of their exceptions to the initial decision, all parties to the proceeding opposed the use of the ALJ’s methodology, except for the FERC trial staff, which took no position.

During the hearing, the LPSC and the FERC trial staff advocated that the alleged tariff violation should be remedied by the application of Entergy Services’ January 2021 proposed methodology. All other parties, including the PUCT, the City Council, and Entergy Services, opposed any surcharges for the period prior to the March 20, 2021 effective date of the January 2021 filing.

Entergy Services disputes the presiding ALJ’s rulings on issue (3) and filed exceptions to these rulings in July 2024. The ALJ’s initial decision is not binding on the FERC and is an interim step in the hearing process. No refunds will be owed in connection with this proceeding unless and until the FERC requires them in a final order.

The MSS-4 replacement tariff includes protocols that provide for the disclosure of cost inputs, an opportunity for informal discovery procedures, and a challenge process. In April 2025, pursuant to such protocols, the City Council filed with the FERC a formal challenge relating to Entergy Services’ inclusion and allocation of net operating loss carryforward accumulated deferred income taxes in the MSS-4 replacement tariff rates charged to Entergy New Orleans’s monthly bills for calendar year 2023. In May 2025, Entergy Services filed a response to the formal challenge and is awaiting a response from the FERC.

NOTE 3. INCOME TAXES

Details regarding income taxes are presented on FERC Form 1 pages 261-267 and 272-277.

The Registrant Subsidiaries’ estimated tax attributes carryovers and their expiration dates as of December 31, 2025 are as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
Federal net operating losses before 1/1/2018	\$— million	\$812.8 million	\$— million	\$— million	\$— million	\$— million
Year(s) of expiration	N/A	2035-2037	N/A	2037	N/A	N/A
Federal net operating losses - 1/1/2018 forward	\$802.9 million	\$2.2 billion	\$— million	\$— million	\$1.4 billion	\$357.1 million
Year(s) of expiration	N/A	N/A	N/A	N/A	N/A	N/A
State net operating losses	\$628.1 million	\$6 billion	\$— million	\$181.3 million	\$1.1 million	\$314.2 million
Year(s) of expiration	2028-2032	N/A	N/A	N/A	2028	2042-2045
Misc. federal credits	\$16.1 million	\$24.5 million	\$6.2 million	\$17.4 million	\$1.1 million	\$6.3 million
Year(s) of expiration	2038-2045	2035-2045	2038-2045	2037-2045	2039-2045	2029-2045
State credits	\$— million	\$1.1 million	\$8.6 million	\$— million	\$0.6 million	\$19 million
Year(s) of expiration	N/A	N/A	2026-2028	N/A	2027-2033	2026-2028

Unrecognized tax benefits

Accounting standards establish a “more-likely-than-not” recognition threshold that must be met before a tax benefit can be recognized in the financial statements. If a tax deduction is taken on a tax return but does not meet the more-likely-than-not recognition threshold, an increase in income tax liability, above what is payable on the tax return, is required to be recorded.

A reconciliation of the Registrant Subsidiaries’ beginning and ending amount of unrecognized tax benefits for 2025, 2024, and 2023 is as follows:

2025	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Gross balance at January 1, 2025	\$45,413	\$867,116	\$5,989	\$19,508	\$384,333	\$16,415
Additions based on tax positions related to the current year (a)	112,354	75,825	1,768	871	1,934	74,391
Additions for tax positions of prior years (a)	221,636	210,263	709	22	4,048	142,840
Reductions for tax positions of prior years	(1,152)	(6,167)	(555)	(847)	(887)	(165)
Gross balance at December 31, 2025	378,251	1,147,037	7,911	19,554	389,428	233,481
Offsets to gross unrecognized tax benefits:						
Loss and tax credit carryovers	(142,860)	(721,552)	(6,000)	(4,744)	(285,936)	(92,561)
Unrecognized tax benefits net of unused tax attributes	\$235,391	\$425,485	\$1,911	\$14,810	\$103,492	\$140,920

2024	Energy Arkansas	Energy Louisiana	Energy Mississippi	Energy New Orleans	Energy Texas	System Energy
Gross balance at January 1, 2024	\$69,197	\$864,043	(In Thousands) \$5,653	\$19,331	\$415,205	\$14,301
Additions based on tax positions related to the current year	2,732	1,921	237	163	378	833
Additions for tax positions of prior years	25,784	10,357	536	153	560	1,281
Reductions for tax positions of prior years	(52,300)	(9,205)	(437)	(139)	(31,810)	—
Gross balance at December 31, 2024	45,413	867,116	5,989	19,508	384,333	16,415
Offsets to gross unrecognized tax benefits:						
Loss and tax credit carryovers	(30,333)	(753,101)	(4,997)	(11,639)	(314,446)	(16,415)
Unrecognized tax benefits net of unused tax attributes	\$15,080	\$114,015	\$992	\$7,869	\$69,887	\$—

2023	Energy Arkansas	Energy Louisiana	Energy Mississippi	Energy New Orleans	Energy Texas	System Energy
Gross balance at January 1, 2023	\$1,452,819	\$1,350,836	(In Thousands) \$547,548	\$638,726	\$389,366	\$23,702
Additions based on tax positions related to the current year (b)	2,249	332,320	209	78	196	752
Additions for tax positions of prior years	—	—	—	—	94,793	—
Reductions for tax positions of prior years (c)	(148,558)	(458,072)	(16,853)	(191,336)	(67,156)	(9,532)
Settlements (c)	(1,237,313)	(361,041)	(525,251)	(428,137)	(1,994)	(621)
Gross balance at December 31, 2023	69,197	864,043	5,653	19,331	415,205	14,301
Offsets to gross unrecognized tax benefits:						
Loss and tax credit carryovers	(34,683)	(735,612)	(3,778)	(11,721)	(381,561)	(14,301)
Unrecognized tax benefits net of unused tax attributes	\$34,514	\$128,431	\$1,875	\$7,610	\$33,644	\$—

- a. Amounts in 2025 are primarily related to production tax credits generated in 2024 and 2025. See “**Other Tax Matters - Inflation Reduction Act of 2022**” below.
b. The primary additions for Energy Louisiana in 2023 are related to the Energy Louisiana storm cost securitizations as discussed in “**Other Tax Matters - Act 293 Securitizations**” below.
c. Amounts in 2023 are primarily related to the resolution of the 2016-2018 IRS audit as discussed in “**Income Tax Audits - 2016-2018 IRS Audit**” below.

The Registrant Subsidiaries’ balances of unrecognized tax benefits included amounts which, if recognized, would have reduced income tax expense as follows:

	December 31,		
	2025	2024	2023
		(In Millions)	
Energy Arkansas	\$360.3	\$32.6	\$57.2
Energy Louisiana	\$1,141.9	\$868.2	\$862.5
Energy Mississippi	\$1.7	\$1.3	\$1.0
Energy New Orleans	\$18.1	\$18.3	\$18.2
Energy Texas	\$113.6	\$50.3	\$2.9
System Energy	\$218.0	\$4.0	\$3.1

Accrued balances for the possible payment of interest related to unrecognized tax benefits for the Registrant Subsidiaries are as follows:

	December 31,		
	2025	2024	2023
		(In Millions)	
Energy Arkansas	\$9.5	\$8.4	\$7.8
Energy Louisiana	\$13.7	\$5.1	\$1.5
Energy Mississippi	\$4.5	\$3.2	\$2.1
Energy New Orleans	\$1.9	\$0.6	\$0.6
Energy Texas	\$1.3	\$0.5	\$—
System Energy	\$2.3	\$2.9	\$1.9

The Registrant Subsidiaries record interest and penalties related to unrecognized tax benefits in income tax expense. No penalties were recorded in 2025, 2024, and 2023. Interest (net-of-tax) was recorded as follows:

	December 31,		
	2025	2024	2023
		(In Millions)	
Energy Arkansas	\$1.1	\$0.6	\$3.5
Energy Louisiana	\$8.6	\$3.6	(\$2.6)
Energy Mississippi	\$1.3	\$1.1	(\$1.0)
Energy New Orleans	\$1.3	\$—	(\$5.8)
Energy Texas	\$0.8	\$0.5	(\$1.1)
System Energy	(\$0.6)	\$1.0	\$—

Income Tax Audits

Energy and its subsidiaries file U.S. federal and various state income tax returns. IRS examinations are complete for years before 2019. All state taxing authorities’ examinations are complete for years before 2016. Energy regularly defends its positions and works with the IRS to resolve audits. The resolution of audit issues could result in significant changes to the amounts of unrecognized tax benefits in the next twelve months.

2016-2018 IRS Audit

The IRS completed its examination of the 2016 through 2018 tax years and issued a Revenue Agent Report (RAR) for each federal filer under audit in November 2023. Energy agreed to all adjustments contained in the RARs. Energy and the Registrant Subsidiaries recorded all the material effects resulting from the RARs in the fourth quarter of 2023.

Utility Restructurings

In 2017, Entergy New Orleans undertook an internal restructuring, and in 2018, Entergy Arkansas and Entergy Mississippi also participated in internal restructurings under which these three Utility operating companies joined Entergy Louisiana as wholly-owned subsidiaries of Entergy Utility Holding Company, LLC. The change in ownership required Entergy to recognize Entergy Arkansas's nuclear decommissioning liabilities for income tax purposes, which resulted in recognition of a gain for income tax purposes and a corresponding increase in the tax basis of assets, in accordance with the Internal Revenue Code and Treasury Regulations. Entergy determined that there was uncertainty regarding the treatment of certain aspects of the restructurings and recorded provisions for uncertain tax positions which are now considered to be effectively settled in accordance with accounting standards. The reversal of such provisions for uncertain tax positions resulted in a reduction of income tax expense of \$156 million for Entergy Arkansas, \$1 million for Entergy Mississippi, and \$6 million for Entergy New Orleans.

After the restructuring, Entergy Arkansas adopted a new method of accounting for income tax purposes in which its nuclear decommissioning costs are treated as production costs of electricity includable in cost of goods sold, which resulted in a \$1.8 billion reduction in taxable income on its 2018 tax return that was treated as an unrecognized tax benefit. In conjunction with the audit, Entergy agreed with the IRS adjustments concerning the nuclear decommissioning tax position allowing Entergy Arkansas to include \$102 million of its decommissioning liability in cost of goods sold.

Mark-to-Market Method of Accounting

In 2018, Entergy Arkansas and Entergy Mississippi each accrued approximately \$2 billion in deductions upon which deferred tax liabilities were recorded related to mark-to-market tax accounting for the Unit Power Sales Agreement and various wholesale electric contracts. The IRS allowed the mark-to-market tax method of accounting associated with various intercompany and third-party wholesale electric contracts. The IRS disallowed the net deductions associated with the Unit Power Sales Agreement, which did not have an effect on net tax expense. The effective settlement of the mark-to-market tax position for Entergy Arkansas resulted in the accrual of an increase to tax expense of \$40 million, which was offset by approximately \$5 million of miscellaneous excess ADIT recognized as a result of the 2016-2018 IRS audit resolution. The net increase to tax expense is deferred as a regulatory asset, as discussed within the "Regulatory and Other Matters" section below.

Reduction of Net Operating Loss Carryovers

The IRS audit reduced Entergy's net operating loss carryover by \$8 billion. A portion of Entergy's audit adjustments were not offset by losses which resulted in a tax liability of \$79 million, which was fully offset by prior deposits made by Entergy. Entergy received an assessment of interest in excess of prior deposits of \$13 million in December 2023, and such interest was paid in January 2024.

Net operating loss carryovers were reduced by \$4 billion for Entergy Arkansas, \$1 billion for Entergy Louisiana, \$2 billion for Entergy Mississippi, \$1 billion for Entergy New Orleans, and \$40 million for System Energy. The IRS audit adjustments were also factored into the settle-up required under Entergy's ETAA, and such amounts were settled in the fourth quarter of 2023.

Regulatory and Other Matters

In December 2023, a regulatory asset for income tax associated with deficient ADIT of \$35 million, \$2 million, and \$3 million, was recorded for Entergy Arkansas, Entergy Louisiana, and Entergy Mississippi, respectively. See Note 2 to the financial statements for discussion of Entergy Arkansas's regulatory activity related to the Tax Cuts and Jobs Act and discussion of the settlement of Entergy Arkansas's 2023 formula rate plan.

Reversal of net deferred credits associated with the accounting for income taxes upon the resolution of the IRS audit resulted in a reduction/(increase) in income tax expense in December 2023 of \$9 million, \$42 million, (\$2) million, \$2 million, \$2 million, and \$1 million for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy, respectively.

Included in the effect of the IRS audit on the results of operations was the measurement of deferred tax assets and liabilities influenced by the 2017 enactment of the Tax Cuts and Jobs Act income tax rate change discussed below. With the conclusion of the audit, there are no remaining federal unrecognized tax benefits affected by the rate differential which could impact income tax expense and the regulatory liability for income taxes in future periods.

State Income Tax Audits

In the third quarter 2024, Entergy and the Arkansas Department of Finance and Administration resolved the terms of the Arkansas Department of Finance and Administration's outstanding tax assessments related to the examination of the 2014 through 2018 tax years. The agreement resulted in a payment of tax of approximately \$8 million by Entergy. As a result of the income tax audit adjustments and the reversal of a provision for uncertain tax positions, Entergy Arkansas recorded a net reduction in income tax expense of approximately \$18 million, which was offset by approximately \$9 million of income tax expense recorded by other Entergy subsidiaries, resulting in a net reduction in income tax expense for Entergy of \$9 million.

Other Tax Matters

Tax Cuts and Jobs Act (TCJA)

The most significant effect of the TCJA for Entergy and the Registrant Subsidiaries was the change in the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. Entergy had net regulatory liability balances of \$1.1 billion and \$1.2 billion as of December 31, 2025 and December 31, 2024, respectively. These liabilities were primarily associated with the re-measurement of deferred tax assets and liabilities due to the income tax rate change and subsequent amortization of excess ADIT. In addition to the unamortized protected excess ADIT amounts, the net regulatory liability for income taxes includes other regulatory assets and liabilities for income taxes that are primarily for the regulatory asset related to AFUDC, as described in Note 1 to the financial statements.

Excess ADIT is generally classified into two categories: (1) the portion that is subject to the normalization requirements of the TCJA, referred to as "protected", and (2) the portion that is not subject to such normalization provisions, referred to as "unprotected". The majority of the remaining unamortized excess ADIT as of December 31, 2025 is classified as protected. The TCJA mandates the normalization method of accounting for income taxes for excess ADIT associated with public utility property. The TCJA specifies the use of the average rate assumption method (ARAM) to determine the timing of the return of excess ADIT associated with such property. Under ARAM, the excess ADIT is reduced over the remaining life of the asset. Remaining asset lives vary for each Registrant Subsidiary, but the average life of public utility property is typically 30 years or longer. Entergy will amortize the protected portion of the excess ADIT in compliance with the normalization requirements.

Entergy's net regulatory liability for income taxes includes a gross-up using the applicable tax rate to account for the effect of income taxes on the revenue requirement in the ratemaking formula. The Registrant Subsidiaries' December 31, 2025 and December 31, 2024 balance sheets reflect net regulatory liabilities for income taxes as follows:

	2025	2024
		(In Millions)
Entergy Arkansas	\$423	\$418
Entergy Louisiana	\$313	\$355
Entergy Mississippi	\$171	\$181
Entergy New Orleans	\$16	\$15
Entergy Texas	\$58	\$94
System Energy	\$100	\$105

Inflation Reduction Act of 2022

The Inflation Reduction Act of 2022, signed into law on August 16, 2022, significantly expanded federal tax incentives for clean energy production, including the extension of production tax credits to solar projects and certain qualified nuclear power facilities.

Entergy Arkansas accrued solar production tax credits associated with the Walnut Bend Solar facility, the Driver Solar facility, and the West Memphis Solar facility of approximately \$5 million in 2024 and approximately \$35 million in 2025. As the value of such credits is expected to be provided to customers, a regulatory liability has been recorded for all credits recognized.

In second quarter 2025, Entergy, Entergy Arkansas, Entergy Louisiana, and System Energy determined, based on current analysis and evolving regulatory developments, that it was appropriate to record zero-emission nuclear production tax credits under Internal Revenue Code section 45U for electricity generated in 2024 by their respective nuclear power facilities. Such credits have been claimed on the Entergy 2024 federal income tax return. Because the U.S. Treasury and the IRS have not issued final guidance regarding the application of Internal Revenue Code section 45U, including the definition of "gross receipts," Entergy treated the full amount of the Internal Revenue Code section 45U credits as an uncertain tax position in accordance with the income tax accounting standards.

The value of the nuclear production tax credits was calculated based on the amount of electricity generated and sold by each nuclear generating unit owned by Entergy Arkansas, Entergy Louisiana, and System Energy during the year, multiplied by the applicable credit rate (i.e., dollars per kWh). The applicable credit rate included the incremental amount of credit for meeting the "prevailing wages" criteria under the Inflation Reduction Act. Entergy also applied the statutorily required reduction amount in arriving at the value of the nuclear production tax credits. This reduction amount was driven by the "gross receipts" received by each unit for its yearly energy production. For credits claimed on the Entergy 2024 federal income tax return, Entergy Arkansas, Entergy Louisiana, and System Energy recognized nuclear production tax credits of \$221.4 million, \$208.9 million, and \$140.9 million, respectively, resulting in Entergy consolidated nuclear production

tax credits of \$571.2 million recognized in second quarter 2025. Additionally, in fourth quarter 2025, Entergy Arkansas, Entergy Louisiana, and System Energy recognized nuclear production tax credits expected to be claimed on the Entergy 2025 federal income tax return of \$104.4 million, \$58.6 million, and \$72.1 million, respectively, resulting in Entergy consolidated nuclear production tax credits of \$235.1 million. Entergy also treated the full amount of the 2025 Internal Revenue Code section 45U credits as an uncertain tax position in accordance with the income tax accounting standards. To the extent future guidance allows Entergy to recognize the value of the credits under the provisions of income tax accounting standards, the monetized value of the production tax credits, net of applicable expenses, is expected to be shared with customers.

During September and October 2025, Entergy Arkansas, Entergy Louisiana, and System Energy transferred the 2024 nuclear production tax credits to third parties and received cash of \$210.1 million, \$198.3 million, and \$133.8 million, respectively, resulting in total Entergy cash receipts of \$542.2 million. In addition, Entergy Arkansas sold its 2024 solar production tax credits to a third party and received cash receipts of approximately \$5.1 million. The proceeds from the transfers reflected a market-based discount. In accordance with the Unit Power Sales Agreement and the MSS-4 replacement tariff, portions of the net proceeds from the transfers of the production tax credits were paid by Entergy Arkansas, Entergy Louisiana, and System Energy to the buyers of energy and capacity under those wholesale agreements. These provisions include the right to recover the transferred proceeds from the 2024 nuclear production tax credits and associated costs if all or a portion of the value of the credits is disallowed by the IRS. Based on these provisions and the uncertainty regarding the tax position, Entergy Arkansas, Entergy Louisiana, and System Energy recognized deferred debits upon flowing through the proceeds of the credits. The Utility operating companies receiving the proceeds from the nuclear production tax credits recognized corresponding deferred credits. These intercompany balances are eliminated on Entergy's consolidated balance sheet.

In January 2026 the APSC opened a docket to investigate the sale of Entergy Arkansas's nuclear production tax credits and the appropriate ratemaking treatment of production tax credits for all of Entergy Arkansas's eligible resources, including how the proceeds of any sales should flow through to customers. As directed by the APSC, in February 2026, Entergy Arkansas submitted a compliance filing to the APSC verifying the status of the solar production tax credits. The filing also verified that the net proceeds from the sale of the nuclear production tax credits were recorded in FERC accounts that are accruing a return for customers' benefit at a rate that is above the customer deposit rate. Entergy will continue to monitor further developments and reassess the uncertain tax position as additional guidance or other information emerges.

Tax Accounting Methods

Certain Entergy subsidiaries have elected to apply the mark-to-market method of accounting for income tax return purposes to wholesale power purchase agreements as appropriate under the Internal Revenue Code and U.S. Treasury Regulations. The mark-to-market tax gain or loss computed each year is based on an estimated fair market valuation which includes analyses of market prices and conditions.

Arkansas Corporate Income Tax Rate Changes

Since 2019, the State of Arkansas has enacted corporate income tax law changes that have phased in rate reductions from the former rate of 6.5% to the currently enacted rate of 4.3%. As a result of the rate reductions, Entergy Arkansas has recorded regulatory liabilities for income taxes of approximately \$29 million, \$26 million, and \$15 million in 2024, 2023, and 2022, respectively, and a total of \$32 million for years prior to 2022. The regulatory liabilities include a tax gross-up related to the treatment of income taxes in the retail and wholesale ratemaking formulas and have been or are scheduled to be included in future rate mechanisms.

NOTE 4. REVOLVING CREDIT FACILITIES, LINES OF CREDIT, AND SHORT-TERM BORROWINGS

Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas each had credit facilities available as of December 31, 2025 as follows:

Company	Expiration Date	Amount of Facility	Interest Rate (a)	Amount Drawn as of December 31, 2025	Letters of Credit Outstanding as of December 31, 2025
Entergy Arkansas	April 2026	\$25 million (b)	5.67%	—	—
Entergy Arkansas	June 2030	\$300 million (c)	4.94%	—	—
Entergy Louisiana	June 2030	\$400 million (c)	5.07%	—	—
Entergy Mississippi	June 2030	\$300 million (c)	4.94%	—	—
Entergy New Orleans	June 2027	\$25 million (c)	5.44%	—	—
Entergy Texas	June 2030	\$300 million (c)	5.07%	—	\$1.1 million

- The interest rate is the estimated interest rate as of December 31, 2025 that would have been applied to outstanding borrowings under the facility.
- Borrowings under this Entergy Arkansas credit facility may be secured by a security interest in its accounts receivable at Entergy Arkansas's option.
- The credit facility includes fronting commitments for the issuance of letters of credit against a portion of the borrowing capacity of the facility as follows: \$5 million for Entergy Arkansas; \$15 million for Entergy Louisiana; \$5 million for Entergy Mississippi; \$10 million for Entergy New Orleans; and \$25 million for Entergy Texas.

The commitment fees on the credit facilities range from 0.075% to 0.375% of the undrawn commitment amount for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy Texas, and of the entire facility amount for Entergy New Orleans. Each of the credit facilities requires the Registrant Subsidiary borrower to maintain a debt ratio, as defined, of 65% or less of its total capitalization. Each Registrant Subsidiary is in compliance with this covenant.

In addition, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas each has one or more uncommitted standby letter of credit facilities as a means to post collateral to support its obligations to MISO and for other purposes. The following is a summary of the uncommitted standby letter of credit facilities as of December 31, 2025:

Company	Amount of Uncommitted Facility	Letter of Credit Fee	Letters of Credit Issued as of December 31, 2025 (a)
Entergy Arkansas	\$25 million	0.78%	\$18.3 million
Entergy Arkansas	\$75 million	0.50%	\$75.0 million
Entergy Louisiana	\$125 million	0.78%	\$119.1 million
Entergy Louisiana	\$45 million	0.50%	\$45.0 million
Entergy Mississippi	\$65 million	0.78%	\$44.4 million
Entergy Mississippi	\$65 million	0.50%	\$43.0 million
Entergy New Orleans	\$1 million	1.625%	\$0.5 million
Entergy Texas	\$150 million	1.250%	\$59.6 million
Entergy Texas	\$160 million	1.05%	\$—

- As of December 31, 2025, letters of credit posted with MISO covered financial transmission rights exposure of \$0.1 million for Entergy Arkansas. See Note 15 to the financial statements for discussion of financial transmission rights.

The short-term borrowings of the Registrant Subsidiaries are limited to amounts authorized by the FERC. The FERC-authorized short-term borrowing limit for Entergy Arkansas is effective through February 2028. In addition to borrowings from commercial banks, these companies may also borrow from the Entergy system money pool and from other internal short-term borrowing arrangements. The money pool is an intercompany cash management program that makes possible intercompany borrowing and lending arrangements, and the money pool and the other internal borrowing arrangements are designed to reduce the Registrant Subsidiaries' dependence on external short-term borrowings. Borrowings from internal and external short-term borrowings combined may not exceed the FERC-authorized limits. The following are the FERC-authorized limits for short-term borrowings and the outstanding short-term borrowings as of December 31, 2025 (aggregating both internal and external short-term borrowings) for the Registrant Subsidiaries:

	Authorized	Borrowings
	(In Millions)	
Entergy Arkansas	\$250	\$—
Entergy Louisiana	\$450	\$—
Entergy Mississippi	\$200	\$—
Entergy New Orleans	\$150	\$—
Entergy Texas	\$200	\$—
System Energy	\$200	\$16

NOTE 5. LONG - TERM DEBT

Details of long-term debt are presented on FERC Form 1 pages 256-257. Entergy Arkansas has obtained long-term financing authorization from the FERC that extends through February 2028. Entergy Arkansas has also obtained first mortgage bond/secured financing authorization from the APSC that extends through December 2027.

NOTE 6. PREFERRED EQUITY AND NONCONTROLLING INTERESTS

Note 6 to the financial statements is not applicable to Entergy Arkansas.

NOTE 7. COMMON EQUITY

Note 7 to the financial statements is not applicable to Entergy Arkansas.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Entergy and the Registrant Subsidiaries are involved in a number of legal, regulatory, and tax proceedings before various courts, regulatory authorities, and governmental agencies in the ordinary course of business. While management is unable to predict with certainty the outcome of such proceedings, management does not believe that the ultimate resolution of these matters will have a material adverse effect on Entergy's results of operations, cash flows, or financial condition. Entergy discusses regulatory proceedings in Note 2 to the financial statements and discusses tax proceedings in Note 3 to the financial statements.

Spent Nuclear Fuel Litigation

Under the Nuclear Waste Policy Act of 1982, the DOE is required, for a specified fee, to construct storage facilities for, and to dispose of, all spent nuclear fuel and other high-level radioactive waste generated by domestic nuclear power reactors. Entergy's nuclear owner/licensee subsidiaries have been charged fees for the estimated future disposal costs of spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. The affected Entergy companies entered into contracts with the DOE, whereby the DOE is to furnish disposal services at a cost of one mill per net kWh generated and sold after April 7, 1983, plus a one-time fee for generation prior to that date. Entergy considers all costs incurred for the disposal of spent nuclear fuel, except accrued interest, to be proper components of nuclear fuel expense. Provisions to recover such costs have been or will be made in applications to regulatory authorities for the Utility plants. Following the defunding of the Yucca Mountain spent fuel repository program, the National Association of Regulatory Utility Commissioners and others sued the government seeking cessation of collection of the one mill per net kWh generated and sold after April 7, 1983 fee. In November 2013 the D.C. Circuit ordered the DOE to submit a proposal to Congress to reset the fee to zero until the DOE complies with the Nuclear Waste Policy Act or Congress enacts an alternative waste disposal plan. In January 2014 the DOE submitted the proposal to Congress under protest, and also filed a petition for rehearing with the D.C. Circuit. The petition for rehearing was denied. The zero spent fuel fee went into effect prospectively in May 2014.

Because the DOE has not begun accepting spent fuel, it is in non-compliance with the Nuclear Waste Policy Act of 1982 and is in partial breach of its spent fuel disposal contracts. As a result of the DOE's failure to begin disposal of spent nuclear fuel in 1998 pursuant to the Nuclear Waste Policy Act of 1982 and the spent fuel disposal contracts, Entergy's nuclear owner/licensee subsidiaries have incurred and will continue to incur damages. Beginning in November 2003 these subsidiaries have pursued litigation to recover the damages caused by the DOE's delay in performance. Following are details of final judgments recorded by Entergy in 2023 and 2024 related to Entergy's nuclear owner/licensee subsidiaries' litigation with the DOE.

In March 2023 the DOE submitted an offer of judgment to resolve claims in the fourth round ANO damages case. The \$41 million offer was accepted by Entergy Arkansas, and the U.S. Court of Federal Claims issued a judgment in that amount in favor of Entergy Arkansas and against the DOE. Entergy Arkansas received payment from the U.S. Treasury in April 2023. The effects of recording the judgment were reductions to plant, nuclear fuel expense, other operation and maintenance expenses, materials and supplies, and taxes other than income taxes. The ANO damages awarded included \$18 million related to costs previously recorded as plant, \$10 million related to costs previously recorded as other operation and maintenance expenses, \$8 million related to costs previously recorded as nuclear fuel expense, \$3 million related to costs previously recorded as materials and supplies, and \$2 million related to costs previously recorded as taxes other than income taxes.

Management cannot predict the timing or amount of any potential recoveries on other claims filed by Entergy subsidiaries and cannot predict the timing of any eventual receipt from the DOE of the U.S. Court of Federal Claims damage awards.

Nuclear Insurance

Third Party Liability Insurance

The Price-Anderson Act requires that reactor licensees purchase insurance and participate in a secondary insurance pool that provides insurance coverage for the public in the event of a nuclear power plant accident. The costs of this insurance are borne by the nuclear power industry. Congress amended and renewed the Price-Anderson Act in 2024 for a term through 2065. The Price-Anderson Act requires nuclear power plants to show evidence of financial protection in the event of a nuclear accident. This protection must consist of two layers of coverage:

1. The primary level is insurance underwritten by American Nuclear Insurers (ANI) and provides public liability insurance coverage of \$500 million for each operating reactor nuclear site. If this amount is not sufficient to cover claims arising from an accident, the second level, Secondary Financial Protection, applies.
2. Secondary Financial Protection: Currently, 95 nuclear reactors participate in the Secondary Financial Protection program, which provides approximately \$15.8 billion in secondary layer insurance coverage to compensate the public in the event of a nuclear power reactor accident. The Price-Anderson Act provides that all potential liability for a nuclear accident is limited to the amounts of insurance coverage available under the primary and secondary layers.

Within the Secondary Financial Protection program, each nuclear reactor has a contingent obligation to pay a retrospective premium, equal to its proportionate share of the loss in excess of the primary level, regardless of proximity to the incident or fault, up to a maximum of approximately \$165.9 million per reactor per incident. For Entergy's five reactors, the maximum total contingent obligation per incident is \$829.6 million. This retrospective premium is assessable at approximately \$24.7 million per year per incident per nuclear power reactor.
3. Total insurance coverage available is approximately \$16.3 billion, among the primary ANI coverages and the Secondary Financial Protection program, to respond to a nuclear power plant accident that causes third-party damages (e.g., off-site property and environmental damage, off-site bodily injury, and on-site third-party bodily injury (i.e., contractors)). These coverages also respond to an accident caused by terrorism.

Entergy Arkansas and Entergy Louisiana each have two licensed reactors. System Energy has one licensed reactor (10% of Grand Gulf is owned by a non-affiliated company (Cooperative Energy) that would share on a pro-rata basis in any retrospective premium assessment to System Energy under the Price-Anderson Act).

Property Insurance

Entergy's nuclear owner/licensee subsidiaries are members of NEIL, a mutual insurance company that provides property damage coverage, including decontamination and reactor stabilization, to the members' nuclear generating plants. The property damage insurance limits procured by Entergy for its nuclear plants are in compliance with the financial protection requirements of the NRC. These coverage limits, deductibles, and weekly indemnity periods are subject to change based on results of NEIL loss control inspections.

The nuclear plants' ANO 1 and 2, Grand Gulf, River Bend, and Waterford 3 property damage insurance limits are \$1.06 billion per occurrence at each plant. The property deductible at the nuclear plants is \$20 million per site, except for earth movement, flood, and windstorm. Property damage from earth movement is excluded from the first \$500 million in coverage for all nuclear plants. Property damage from flood is excluded from the first \$500 million in coverage at ANO 1 and 2 and Grand Gulf. Property damage from flood for Waterford 3 and River Bend is subject to a deductible of \$10 million plus an additional 10% of the amount

of the loss in excess of \$10 million, up to a maximum deductible of \$50 million. Property damage from a windstorm for all the nuclear plants is subject to a deductible of \$10 million plus an additional 10% of the amount of the loss in excess of \$10 million, up to a total maximum deductible of \$50 million.

Under the property damage and accidental outage insurance programs, all NEIL-insured plants could be subject to assessments should losses exceed the accumulated funds available from NEIL. The retrospective premium assessments are subject to change based on results of NEIL underwriting, and the potential obligation to pay this assessment remains for six years after the end of the policy period, unless a prior call is made. NEIL has exercised this assessment. The maximum aggregate amounts of such possible assessments for the current year's policies are as follows:

	<u>Assessments</u>
	(In Millions)
Entergy Arkansas	\$20.1
Entergy Louisiana	\$40.1
Entergy Mississippi	\$0.3
Entergy New Orleans	\$0.1
Entergy Texas	N/A
System Energy	\$15.5

NRC regulations provide that the proceeds of this insurance must be used, first, to render the reactor safe and stable, and second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured would any remaining proceeds be made available for the benefit of plant owners or their creditors.

In the event that one or more acts of terrorism causes property damage from a nuclear event under one or more or all nuclear insurance policies issued by NEIL (including, but not limited to, those described above) within 12 months from the date the first property damage occurs, the maximum recovery under all such nuclear insurance policies shall be an aggregate not exceeding \$3.24 billion plus the additional amounts recovered for such losses from reinsurance, indemnity, and any other sources applicable to such losses.

Non-Nuclear Property Insurance

Entergy's non-nuclear property insurance program provides coverage on a system-wide basis for Entergy's non-nuclear assets. The insurance program provides coverage for property damage up to \$400 million per occurrence in excess of a \$20 million self-insured retention except for property damage caused by the following: earthquake shock, flood, and named windstorm, including associated storm surge. For earthquake shock and flood, the insurance program provides coverage up to \$400 million on an annual aggregate basis in excess of a \$40 million self-insured retention. For named windstorm and associated storm surge, the insurance program provides coverage up to approximately \$135 million on an annual aggregate basis in excess of a \$40 million self-insured retention.

Covered property generally includes power plants, substations, facilities, and inventories. Excluded property generally includes transmission and distribution lines, poles, and towers. For substations valued at \$5 million or less, coverage for named windstorm and associated storm surge is excluded. This coverage is in place for Entergy Corporation, the Registrant Subsidiaries, and certain other Entergy subsidiaries. Entergy also purchases \$400 million in terrorism insurance coverage for its conventional property.

Employment and Labor-related Proceedings

The Registrant Subsidiaries and other Entergy subsidiaries and related entities are responding to various lawsuits in both state and federal courts and to other labor-related proceedings filed by current and former employees, recognized bargaining representatives, and certain third parties. Generally, the amount of damages being sought is not specified in these proceedings. These actions may include, but are not limited to, allegations of wrongful employment actions; wage disputes and other claims under the Fair Labor Standards Act or its state counterparts; claims of race, gender, age, and disability discrimination; disputes arising under collective bargaining agreements; unfair labor practice proceedings and other administrative proceedings before the National Labor Relations Board or concerning the National Labor Relations Act; claims of retaliation; claims of harassment and hostile work environment; and claims for or regarding benefits under various Entergy Corporation-sponsored employee benefit plans. Entergy and the Registrant Subsidiaries and related entities are responding to these lawsuits and proceedings and deny liability to the claimants. Management believes that loss exposure has been and will continue to be handled so that the ultimate resolution of these matters will not be material, in the aggregate, to the financial position, results of operation, or cash flows of Entergy or the Registrant Subsidiaries.

Asbestos Litigation

Numerous lawsuits have been filed in state courts against primarily Entergy Louisiana and Entergy Texas by individuals alleging exposure to asbestos while working at Entergy facilities between 1955 and 1980. Entergy is being sued as a premises owner. Many other defendants are named in these lawsuits as well. Currently, there are approximately 180 lawsuits involving approximately 330 claimants. Management believes that adequate provisions have been established to cover any exposure. Additionally, negotiations continue with insurers to recover reimbursements. Management believes that loss exposure has been and will continue to be handled so that the ultimate resolution of these matters will not be material, in the aggregate, to the financial position, results of operation, or cash flows of the Utility operating companies.

Grand Gulf-Related Agreements

Unit Power Sales Agreement

System Energy historically sold all of its share of capacity and energy from Grand Gulf to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans in accordance with specified percentages (Entergy Arkansas - 36%, Entergy Louisiana - 14%, Entergy Mississippi - 33%, and Entergy New Orleans - 17%) as ordered by the FERC under the Unit Power Sales Agreement. Charges under this agreement are paid in consideration for the purchasing companies' respective entitlement to receive capacity and energy and are payable irrespective of the quantity of energy delivered. Grand Gulf's operating license currently extends through 2044. Monthly obligations are based on actual capacity and energy costs. The average monthly payments for 2025 under the agreement were approximately \$15.8 million for Entergy Arkansas, \$6.7 million for Entergy Louisiana, \$19.3 million for Entergy Mississippi, and \$8.5 million for Entergy New Orleans. Effective October 1, 2025, System Energy began selling all of its share of capacity and energy from Grand Gulf to Entergy Arkansas, Entergy Mississippi, and Entergy New Orleans in accordance with specified percentages (Entergy Arkansas - 24.19%, Entergy Mississippi - 56.38%, and Entergy New Orleans - 19.43%) as approved by the FERC under an amended Unit Power Sales Agreement. See Note 2 to the financial statements for discussion of proceedings regarding the Unit Power Sales Agreement.

Availability Agreement (Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and System Energy)

Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (Entergy Arkansas - 17.1%, Entergy Louisiana - 26.9%, Entergy Mississippi - 31.3%, and Entergy New Orleans - 24.7%) in amounts that, when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses as defined, including expenses incurred in connection with a permanent shutdown of Grand Gulf. System Energy has assigned its rights to payments and advances to certain creditors as security for certain of its debt obligations. Effective October 1, 2025, System Energy, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans terminated the Availability Agreement. Also effective October 1, 2025, System Energy, Entergy Arkansas, Entergy Mississippi, and Entergy New Orleans entered into a new Availability Agreement with allocation percentages conforming to their entitlement percentages under the amended Unit Power Sales Agreement. Since commercial operation of Grand Gulf began, payments under the Unit Power Sales Agreement to System Energy have exceeded the amounts payable under either Availability Agreement and, therefore, no payments under either Availability Agreement have ever been required.

Exclusivity Agreement with Major Vendor

Entergy entered into an exclusivity agreement with a major vendor to manufacture power island equipment (PIE) and combustion turbines (CT) for combustion turbine generator set frames larger than 400 MWs. The agreement guarantees Entergy one manufacturing slot per quarter for the shorter of a five-year period or until Entergy fulfills its minimum commitment. The agreement was amended in third quarter 2025, updating the minimum order of 15 sets of PIE and two CTs to a minimum order of 21 sets of PIE and two CTs during that time period, of which seven sets of PIE and two CT slots have been fulfilled. The commitments are fully transferable to any of the Utility operating companies. Cancellation or failure to purchase the minimum commitment amounts will result in a charge.

If any of the Utility operating companies purchases any CTs within the scope of the agreement from another supplier (except as permitted under the agreement), then the vendor has the right to terminate all or a portion of the agreement. In the event of such termination, the Utility operating company would then be obligated to pay 50% of the CT base price for each PIE or CT not yet ordered. The agreement does not establish final pricing and delivery dates of purchases that will go towards meeting the commitments under the agreement. Such terms shall be agreed to in separate agreements.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

Accounting standards require companies to record liabilities for all legal obligations associated with the retirement of long-lived assets that result from the normal operation of the assets. For Entergy, substantially all of its asset retirement obligations consist of its liability for decommissioning its nuclear power plants. The remainder of removal costs included in the decommissioning and asset retirement costs line item on the balance sheets is associated with non-nuclear power plants.

These liabilities are recorded at their fair values (which are the present values of the estimated future cash outflows) in the period in which they are incurred, with an accompanying addition to the recorded cost of the long-lived asset. The asset retirement obligation is accreted each year through a charge to expense, to reflect the time value of money for this present value obligation. The accretion will continue through the completion of the asset retirement activity. The amounts added to the carrying amounts of the long-lived assets will be depreciated over the useful lives of the assets. The application of accounting standards related to asset retirement obligations is earnings neutral to the rate-regulated business of the Registrant Subsidiaries.

The cumulative decommissioning and retirement cost liabilities and expenses recorded in 2025 and 2024 for Entergy and the Registrant Subsidiaries were as follows:

	Entergy	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Millions)			
Liabilities as of December 31, 2023	\$4,505.8	\$1,560.1	\$1,836.2	\$8.2	\$4.6	\$11.7	\$1,084.2
Liabilities incurred (a)	41.1	17.7	19.4	4.0	—	—	—
Accretion	233.8	93.6	94.4	1.1	0.3	0.8	43.5
Change in cash flow estimate	(67.3)	20.2	(107.1)	11.8	—	5.2	—
Liabilities as of December 31, 2024	4,713.4	1,691.6	1,842.9	25.1	4.9	17.7	1,127.7
Accretion	243.1	100.7	94.1	1.4	0.3	0.8	45.3
Change in cash flow estimate	(9.0)	(0.9)	(4.6)	—	—	(3.4)	—
Liabilities as of December 31, 2025	\$4,947.5	\$1,791.4	\$1,932.4	\$26.5	\$5.2	\$15.1	\$1,173.0

a. See "Other" below for additional discussion regarding the asset retirement obligations established at Entergy Arkansas, Entergy Louisiana, and Entergy Mississippi.

Nuclear Plant Decommissioning

Entergy periodically reviews and updates estimated decommissioning costs. The actual decommissioning costs may vary from the estimates because of the timing of plant decommissioning, regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment.

In first quarter 2024, Entergy Arkansas recorded a revision to its estimated decommissioning cost liabilities for ANO 1 and 2 as a result of a revised decommissioning cost study. The revised estimates resulted in a \$14.4 million decrease in its decommissioning cost liabilities, along with corresponding decreases in the related asset retirement cost assets that will be depreciated over the remaining useful lives of the units.

NRC Filings Regarding Trust Funding Levels

Plant owners are required to provide the NRC with a biennial report (annually for units that have shut down or will shut down within five years), based on values as of December 31, addressing the owners' ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, plant owners may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met.

As nuclear plants individually approach and begin decommissioning, filings will be submitted to the NRC for planned shutdown activities. These filings with the NRC also determine whether financial assurance may be required in addition to the nuclear decommissioning trust fund.

Coal Combustion Residuals

In April 2015 the EPA published the final coal combustion residuals (CCR) rule regulating CCRs destined for disposal in landfills or surface impoundments as non-hazardous wastes regulated under Resource Conservation and Recovery Act Subtitle D. The final regulations created new compliance requirements including modified storage, new notification and reporting practices, product disposal considerations, and CCR unit closure criteria, but excluded CCRs that are beneficially reused in certain processes. Entergy believes that on-site disposal options will be available at its facilities, to the extent needed.

In second quarter 2024, revisions were recorded to the estimated decommissioning cost liabilities for White Bluff and Independence as a result of the EPA rule that was finalized in May 2024 establishing management standards for legacy CCR surface impoundments (i.e., inactive surface impoundments at inactive power plants) and establishing a new class of units referred to as CCR management units (CCRMUs) (i.e., non-containerized CCR located at a regulated CCR facility). Entergy does not have any legacy impoundments; however, the definition of CCR management units includes on-site areas where CCR was beneficially used. This is contrary to the previous CCR rule which exempted beneficial uses that met certain criteria. Under this expanded rule, all facilities must identify and delineate any CCRMU greater than one ton and submit a facility evaluation report by February 2026. In July 2025 the EPA extended the deadline for submission of the facility evaluation report by one year to February 2027. Any potential requirements for corrective action or operational changes under the various CCR rules continue to be assessed. Given the complexity and recency of the EPA guidance, Entergy is still evaluating the level of work that will ultimately be required to comply with the rule.

Based on initial estimates of multiple possible remediation scenarios, Entergy Arkansas and Entergy Mississippi recorded increases of \$31.2 million and \$9.1 million, respectively, in their decommissioning cost liabilities in 2024, along with corresponding increases in the related asset retirement cost assets that will be depreciated over the remaining useful lives of the units. Entergy will continue to update the asset retirement obligation as the requirements of the revised CCR rule are clarified.

Other

In 2024, Entergy Arkansas recorded asset retirement obligations to reflect decommissioning costs related to obligations to remove the electrical systems and return the land to its normal condition under the respective land lease agreements for the Walnut Bend Solar facility and the Driver Solar facility. These estimates resulted in the establishment of a decommissioning cost liability of \$4.5 million for the Walnut Bend Solar facility and of \$13.2 million for the Driver Solar facility, along with the establishment of related asset retirement cost assets that will be depreciated over the remaining initial lease terms, respectively. See Note 14 to the financial statements for discussion of Entergy Arkansas's purchase of the Walnut Bend Solar facility and the Driver Solar facility.

NOTE 10. LEASES

As of December 31, 2025 and 2024, Entergy and the Registrant Subsidiaries held operating and finance leases for fleet vehicles used in operations, real estate, and aircraft. Excluded from this discussion of leases are power purchase agreements not meeting the definition of a lease and nuclear fuel leases.

Leases have remaining terms of one year to 55 years. Real estate leases generally include at least one five-year renewal option; however, renewal is not typically considered reasonably certain unless Entergy or a Registrant Subsidiary makes significant leasehold improvements or other modifications that would hinder its ability to easily move. In certain of the lease agreements for fleet vehicles used in operations, Entergy and the Registrant Subsidiaries provide residual value guarantees to the lessor. Historically, Entergy has renegotiated or refinanced these lease agreements prior to their conclusion and expects to continue this practice, given the nature of the agreements and its ongoing relationship with the lessor. As such, Entergy and the Registrant Subsidiaries do not believe it is probable that they will be required to pay anything pertaining to the residual value guarantee, and the lease liabilities and right-of-use assets are measured accordingly.

The Registrant Subsidiaries incurred the following lease costs for the year ended December 31, 2025:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
Operating lease cost	\$19,633	\$19,875	\$9,696	\$2,094	\$8,396
Finance lease cost:					
Amortization of right-of-use assets	\$5,834	\$5,820	\$2,726	\$653	\$2,376
Interest on lease liabilities	\$1,714	\$1,207	\$1,153	\$151	\$484

Of the lease costs disclosed above, Entergy Arkansas had \$1.6 million in short-term lease costs for the year ended December 31, 2025.

The Registrant Subsidiaries incurred the following lease costs for the year ended December 31, 2024:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
Operating lease cost	\$19,382	\$19,770	\$9,482	\$2,234	\$7,977
Finance lease cost:					
Amortization of right-of-use assets	\$4,675	\$5,755	\$2,604	\$1,240	\$2,104
Interest on lease liabilities	\$990	\$1,068	\$1,116	\$264	\$399

Of the lease costs disclosed above, Entergy Arkansas had \$1.1 million in short-term lease costs for the year ended December 31, 2024.

The lease costs for the years ended December 31, 2025 and 2024 disclosed above materially approximate the cash flows used by the Registrant Subsidiaries for leases with all costs included within operating activities on the respective Statements of Cash Flows, except for the finance lease costs which are included in financing activities.

Entergy has elected to account for short-term leases in accordance with policy options provided by accounting guidance; therefore, there are no related lease liabilities or right-of-use assets for the costs recognized above by Entergy or by its Registrant Subsidiaries in the table below.

Included within Utility Plant on the Registrant Subsidiaries' respective balance sheets at December 31, 2025 and 2024 are the following amounts:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
2025					
Operating leases	\$75,148	\$66,726	\$32,502	\$7,940	\$26,070
Finance leases	\$37,616	\$28,637	\$23,456	\$3,613	\$11,550
2024					
Operating leases	\$64,960	\$65,909	\$32,399	\$7,971	\$27,524
Finance leases	\$36,105	\$26,159	\$22,641	\$6,451	\$10,822

The following lease-related liabilities are recorded within the respective Other lines on the Registrant Subsidiaries' respective balance sheets at December 31, 2025:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
Current liabilities:					
Operating leases	\$17,530	\$18,229	\$8,567	\$1,884	\$7,394
Finance leases	\$5,332	\$5,865	\$3,520	\$712	\$2,449
Non-current liabilities:					
Operating leases	\$57,631	\$48,497	\$23,943	\$5,931	\$18,681
Finance leases	\$32,284	\$22,772	\$21,205	\$2,901	\$9,101

The following lease-related liabilities are recorded within the respective Other lines on the Registrant Subsidiaries' respective balance sheets at December 31, 2024:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
Current liabilities:					
Operating leases	\$17,159	\$17,016	\$8,116	\$1,885	\$7,387
Finance leases	\$3,734	\$5,620	\$3,228	\$1,218	\$2,185
Non-current liabilities:					
Operating leases	\$47,799	\$48,896	\$24,294	\$5,995	\$20,142
Finance leases	\$32,584	\$20,539	\$20,271	\$5,233	\$8,637

The following information contains the weighted-average remaining lease term in years and the weighted-average discount rate for the operating and finance leases of the Registrant Subsidiaries at December 31, 2025:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
Weighted-average remaining lease terms:					
Operating leases	5.14	4.41	5.00	5.70	4.29
Finance leases	10.58	5.73	16.54	5.60	5.65
Weighted-average discount rate:					
Operating leases	4.35%	4.52%	4.56%	4.50%	4.62%
Finance leases	4.49%	4.54%	5.23%	4.36%	4.43%

The following information contains the weighted-average remaining lease term in years and the weighted-average discount rate for the operating and finance leases of the Registrant Subsidiaries at December 31, 2024:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
Weighted-average remaining lease terms:					
Operating leases	4.39	4.64	5.25	6.08	4.59
Finance leases	11.32	5.60	17.58	5.91	5.74
Weighted-average discount rate:					
Operating leases	4.38%	4.38%	4.52%	4.40%	4.55%
Finance leases	4.38%	4.28%	5.18%	4.19%	4.19%

The undiscounted cash flows as of December 31, 2025 for the Registrant Subsidiaries' lease liabilities are as follows:

Operating Leases

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
2026	\$20,124	\$20,765	\$9,861	\$2,175	\$8,425
2027	18,062	18,530	9,167	1,893	6,900
2028	15,153	15,022	7,670	1,717	5,968
2029	10,558	9,927	4,927	1,301	4,352
2030	6,937	4,984	2,227	638	1,905
Years thereafter	12,481	4,144	2,609	1,149	1,117
Minimum lease payments	83,315	73,372	36,461	8,873	28,667
Less: amount representing interest	8,154	6,646	3,951	1,058	2,592
Present value of net minimum lease payments	\$75,161	\$66,726	\$32,510	\$7,815	\$26,075

Finance Leases

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
2026	\$6,986	\$7,134	\$3,981	\$855	\$2,910
2027	6,368	6,387	3,528	817	2,588
2028	5,540	5,565	3,099	719	2,305
2029	4,605	4,705	2,599	655	1,823
2030	3,972	3,876	2,219	519	1,454
Years thereafter	21,350	5,086	23,718	512	2,002
Minimum lease payments	48,821	32,753	39,144	4,077	13,082
Less: amount representing interest	11,205	4,116	14,419	464	1,532
Present value of net minimum lease payments	\$37,616	\$28,637	\$24,725	\$3,613	\$11,550

In allocating consideration in lease contracts to the lease and non-lease components, Entergy and the Registrant Subsidiaries have made the accounting policy election to combine lease and non-lease components related to fleet vehicles used in operations and to allocate the contract consideration to both lease and non-lease components for real estate leases.

NOTE 11. RETIREMENT, OTHER POSTRETIREMENT BENEFITS, AND DEFINED CONTRIBUTION PLANS

Qualified Pension Plans

Entergy has defined benefit qualified pension plans, including the Entergy Corporation Retirement Plan for Non-Bargaining Employees (Non-Bargaining Plan I), the Entergy Corporation Retirement Plan for Bargaining Employees (Bargaining Plan I), the Entergy Corporation Retirement Plan II for Non-Bargaining Employees (Non-Bargaining Plan II), the Entergy Corporation Retirement Plan II for Bargaining Employees (Bargaining Plan II), the Entergy Corporation Retirement Plan III (Plan III), the Entergy Corporation Retirement Plan IV for Bargaining Employees, Entergy Corporation Retirement Plan VI for Non-Bargaining Employees (Non-Bargaining Plan VI), and the Entergy Corporation Retirement Plan VI for Bargaining Employees (Bargaining Plan VI). The Entergy Corporation Cash Balance Plan for Non-Bargaining Employees (Non-Bargaining Cash Balance Plan) was merged with and into Non-Bargaining Plan I effective January 1, 2022. The Entergy Corporation Cash Balance Plan for Bargaining Employees (Bargaining Cash Balance Plan) was merged with and into Bargaining Plan I effective January 1, 2025. Effective January 1, 2024, Non-Bargaining Plan I was amended to spin-off predominately inactive participants into a new qualified pension plan, Non-Bargaining Plan VI. Effective January 1, 2025, Bargaining Plan I was amended to spin-off predominately inactive participants into a new qualified pension plan, Bargaining Plan VI.

The Registrant Subsidiaries participate in these plans: Non-Bargaining Plan I, Bargaining Plan I, Plan III, Non-Bargaining Plan VI, and Bargaining Plan VI.

Non-bargaining and bargaining employees whose most recent date of hire was prior to June 30, 2014 (or such later date provided for in their applicable collective bargaining agreement) participate in a noncontributory final average pay formula that provides pension benefits based on the employee's credited service and compensation during employment. Non-bargaining and bargaining employees whose most recent date of hire is after June 30, 2014 and before January 1, 2021 (or such later date provided for in their applicable collective bargaining agreement) do not participate in a final average pay formula, but instead participate in a cash balance formula. Effective January 1, 2021, the Non-Bargaining Cash Balance Plan and Bargaining Cash Balance Plan were amended to close participation in each plan to those employees whose most recent hire date is after December 31, 2020 (or such later date provided for in their applicable collective bargaining agreement). Employees hired after this date instead may be eligible to participate in and receive a discretionary employer contribution under an Entergy sponsored tax-qualified defined contribution plan that includes a 401(k) feature.

The assets of the defined benefit qualified pension plans are held in a master trust established by Entergy. Each pension plan has an undivided beneficial interest in each of the investment accounts in the master trust that is maintained by a trustee. Use of the master trust permits the commingling of the trust assets of the pension plans of Entergy Corporation and its Registrant Subsidiaries for investment and administrative purposes. Although assets in the master trust are commingled, the trustee maintains supporting records for the purpose of allocating the trust level equity in net earnings (loss) and the administrative expenses of the investment accounts in the trust to the various participating pension plans in the trust. The fair value of the trust's assets is determined by the trustee and certain investment managers. The trustee calculates a daily earnings factor, including realized and unrealized gains or losses, collected and accrued income, and administrative expenses, and allocates earnings to each plan in the master trust on a pro rata basis.

Within each pension plan, the record of each Registrant Subsidiary's beneficial interest in the plan assets is maintained by the plan's actuary and is updated quarterly. Assets for each Registrant Subsidiary are increased for investment net income and contributions and are decreased for benefit payments. A plan's investment net income/loss (i.e., interest and dividends, realized and unrealized gains and losses and expenses) is allocated to the Registrant Subsidiaries participating in that plan based on the value of assets for each Registrant Subsidiary at the beginning of the quarter adjusted for contributions and benefit payments made during the quarter.

Entergy Corporation and its subsidiaries fund pension plans in an amount not less than the minimum required contribution under the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plans include common and preferred stocks, fixed-income securities, interest in a money market fund, and insurance contracts. The Registrant Subsidiaries' pension costs are recovered from customers as a component of cost of service in each of their respective jurisdictions.

Components of Qualified Net Pension Cost and Other Amounts Recognized as a Regulatory Asset and/or Accumulated Other Comprehensive Income (AOCI)

The Registrant Subsidiaries' total 2025, 2024, and 2023 qualified pension costs and amounts recognized as a regulatory asset and/or other comprehensive income, including amounts capitalized, for their current and former employees included the following components:

2025	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Net periodic pension cost:						
Service cost - benefits earned during the period	\$17,624	\$21,714	\$5,200	\$1,642	\$4,063	\$5,448
Interest cost on projected benefit obligation	54,788	58,102	14,720	6,521	11,780	14,163
Expected return on assets	(70,933)	(75,755)	(19,976)	(8,241)	(15,557)	(18,360)
Recognized net loss	17,923	9,270	3,144	2,237	1,815	4,136
Settlement charges	1,454	5,982	146	6,195	617	512
Asset transfer gain	—	(2,408)	—	(1,983)	—	—
Net pension cost	<u>\$20,856</u>	<u>\$16,905</u>	<u>\$3,234</u>	<u>\$6,371</u>	<u>\$2,718</u>	<u>\$5,899</u>
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net (gain) loss	(\$34,076)	(\$48,025)	(\$8,698)	\$1,767	(\$7,431)	(\$7,439)
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of net loss	(17,923)	(9,270)	(3,144)	(2,237)	(1,815)	(4,136)
Settlement charges	(1,454)	(5,982)	(146)	(6,195)	(617)	(512)
Total	<u>(\$53,453)</u>	<u>(\$63,277)</u>	<u>(\$11,988)</u>	<u>(\$6,665)</u>	<u>(\$9,863)</u>	<u>(\$12,087)</u>
Total recognized as net periodic pension cost, regulatory asset, and/or AOCI (before tax)	<u>(\$32,597)</u>	<u>(\$46,372)</u>	<u>(\$8,754)</u>	<u>(\$294)</u>	<u>(\$7,145)</u>	<u>(\$6,188)</u>
2024	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Net periodic pension cost:						
Service cost - benefits earned during the period	\$16,398	\$22,204	\$5,135	\$1,760	\$3,846	\$5,525
Interest cost on projected benefit obligation	52,870	55,843	14,084	6,276	11,324	13,525
Expected return on assets	(72,620)	(77,786)	(20,451)	(8,814)	(16,308)	(18,485)
Recognized net loss	22,983	10,407	4,562	1,881	1,574	4,638
Settlement charges	—	—	—	—	—	615
Net pension cost	<u>\$19,631</u>	<u>\$10,668</u>	<u>\$3,330</u>	<u>\$1,103</u>	<u>\$436</u>	<u>\$5,818</u>
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net gain	(\$49,352)	(\$55,010)	(\$10,857)	(\$8,990)	(\$6,190)	(\$9,812)
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of net loss	(22,983)	(10,407)	(4,562)	(1,881)	(1,574)	(4,638)
Settlement charges	—	—	—	—	—	(615)
Total	<u>(\$72,335)</u>	<u>(\$65,417)</u>	<u>(\$15,419)</u>	<u>(\$10,871)</u>	<u>(\$7,764)</u>	<u>(\$15,065)</u>
Total recognized as net periodic pension cost, regulatory asset, and/or AOCI (before tax)	<u>(\$52,704)</u>	<u>(\$54,749)</u>	<u>(\$12,089)</u>	<u>(\$9,768)</u>	<u>(\$7,328)</u>	<u>(\$9,247)</u>
2023	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Net periodic pension cost:						
Service cost - benefits earned during the period	\$18,461	\$24,716	\$5,775	\$1,955	\$4,328	\$5,749
Interest cost on projected benefit obligation	56,026	60,346	15,402	6,747	12,726	13,852
Expected return on assets	(70,574)	(75,757)	(19,423)	(8,798)	(16,641)	(17,585)
Recognized net loss	19,400	19,797	5,719	1,694	4,075	4,236
Settlement charges	26,137	40,437	12,242	2,080	11,230	6,375
Net pension cost	<u>\$49,450</u>	<u>\$69,539</u>	<u>\$19,715</u>	<u>\$3,678</u>	<u>\$15,718</u>	<u>\$12,627</u>
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net gain	(\$30,674)	(\$71,016)	(\$20,220)	(\$3,183)	(\$16,759)	(\$3,268)
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of net loss	(19,400)	(19,797)	(5,719)	(1,694)	(4,075)	(4,236)
Settlement charges	(26,137)	(40,437)	(12,242)	(2,080)	(11,230)	(6,375)
Total	<u>(\$76,211)</u>	<u>(\$131,250)</u>	<u>(\$38,181)</u>	<u>(\$6,957)</u>	<u>(\$32,064)</u>	<u>(\$13,879)</u>
Total recognized as net periodic pension cost, regulatory asset, and/or AOCI (before tax)	<u>(\$26,761)</u>	<u>(\$61,711)</u>	<u>(\$18,466)</u>	<u>(\$3,279)</u>	<u>(\$16,346)</u>	<u>(\$1,252)</u>

Qualified Pension Obligations, Plan Assets, Funded Status, Amounts Recognized in the Balance Sheet

Qualified pension obligations, plan assets, funded status, and amounts recognized in the Balance Sheets for the Registrant Subsidiaries as of December 31, 2025 and 2024 are as follows:

2025	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in Projected Benefit Obligation (PBO)						
Balance at January 1	\$1,061,063	\$1,123,024	\$283,071	\$127,133	\$229,942	\$275,117
Service cost	17,624	21,714	5,200	1,642	4,063	5,448
Interest cost	54,788	58,102	14,720	6,521	11,780	14,163
Actuarial loss	21,393	10,104	6,438	5,537	4,963	7,626
Settlement liability transfer	—	(16,391)	—	(21,723)	—	—
Benefits paid	(85,881)	(87,398)	(24,249)	(17,388)	(26,307)	(25,321)
Balance at December 31	\$1,068,987	\$1,109,155	\$285,180	\$101,722	\$224,441	\$277,033
Change in Plan Assets						
Fair value of assets at January 1	\$1,043,188	\$1,111,601	\$294,458	\$125,805	\$228,053	\$269,899
Actual return on plan assets	126,402	133,886	35,112	12,011	27,951	33,425
Employer contributions	35,544	41,253	8,064	5,016	7,725	15,668
Transfer	—	(13,984)	—	(19,740)	—	—
Benefits paid	(85,881)	(87,398)	(24,249)	(17,388)	(26,307)	(25,321)
Fair value of assets at December 31	\$1,119,253	\$1,185,358	\$313,385	\$105,704	\$237,422	\$293,671
Funded status	\$50,266	\$76,203	\$28,205	\$3,982	\$12,981	\$16,638
Amounts recognized in the balance sheet (funded status)						
Non-current assets	\$50,266	\$76,203	\$28,205	\$3,982	\$12,981	\$16,638
Amounts recognized as regulatory asset						
Net loss	\$359,324	\$195,570	\$74,801	\$27,375	\$46,038	\$84,844
Amounts recognized as AOCI (before tax)						
Net loss	\$—	\$8,149	\$—	\$—	\$—	\$—
2024	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in Projected Benefit Obligation (PBO)						
Balance at January 1	\$1,117,585	\$1,173,283	\$295,942	\$133,950	\$239,984	\$286,558
Service cost	16,398	22,204	5,135	1,760	3,846	5,525
Interest cost	52,870	55,843	14,084	6,276	11,324	13,525
Actuarial gain	(48,020)	(46,895)	(10,071)	(6,098)	(6,102)	(8,908)
Benefits paid (a)	(77,770)	(81,411)	(22,019)	(8,755)	(19,110)	(21,583)
Balance at December 31	\$1,061,063	\$1,123,024	\$283,071	\$127,133	\$229,942	\$275,117
Change in Plan Assets						
Fair value of assets at January 1	\$991,894	\$1,058,711	\$280,260	\$117,923	\$222,496	\$255,443
Actual return on plan assets	73,952	85,900	21,237	11,706	16,395	19,389
Employer contributions	55,112	48,401	14,980	4,931	8,272	16,650
Benefits paid	(77,770)	(81,411)	(22,019)	(8,755)	(19,110)	(21,583)
Fair value of assets at December 31	\$1,043,188	\$1,111,601	\$294,458	\$125,805	\$228,053	\$269,899
Funded status	(\$17,875)	(\$11,423)	\$11,387	(\$1,328)	(\$1,889)	(\$5,218)
Amounts recognized in the balance sheet (funded status)						
Non-current assets	\$29,521	\$10,010	\$19,666	\$3,299	\$6,064	\$3,135
Non-current liabilities	(47,396)	(21,433)	(8,279)	(4,627)	(7,953)	(8,353)
Total funded status	(\$17,875)	(\$11,423)	\$11,387	(\$1,328)	(\$1,889)	(\$5,218)
Amounts recognized as regulatory asset						
Net loss	\$412,777	\$256,316	\$86,790	\$34,039	\$55,902	\$96,932
Amounts recognized as AOCI (before tax)						
Net loss	\$—	\$10,680	\$—	\$—	\$—	\$—

The qualified pension plans incurred actuarial gains during 2025 primarily due to asset gains due to an actual return on assets higher than the expected return on assets, partially offset by liability losses due to a fall in bond yields that resulted in decreases to the discount rates used to develop the benefit obligations. The qualified pension plans incurred net actuarial gains during 2024 primarily due to liability gains due to a rise in bond yields that resulted in increases to the discount rates used to develop the benefit obligations; partially offset by asset losses resulting from an actual return on assets lower than the expected return on assets in some plans.

The qualified pension accumulated benefit obligation for each of the Registrant Subsidiaries for their current and former employees as of December 31, 2025 and 2024 was as follows:

	2025	2024
(In Thousands)		
Entergy Arkansas	\$988,724	\$980,559
Entergy Louisiana	\$1,014,433	\$1,024,433
Entergy Mississippi	\$259,995	\$257,759
Entergy New Orleans	\$96,241	\$118,620
Entergy Texas	\$207,772	\$212,935
System Energy	\$253,108	\$252,397

Each of the Registrant Subsidiaries' qualified pension plans had plan assets in excess of the accumulated benefit obligation as of December 31, 2025.

Information for each of the Registrant Subsidiaries qualified pension plans with an accumulated benefit obligation in excess of plan assets as of December 31, 2024 was as follows:

2024	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy Texas	System Energy
(In Thousands)					
Accumulated benefit obligation	\$304,518	\$123,735	\$105,285	\$58,082	\$44,286
Fair value of plan assets	\$297,161	\$115,446	\$103,380	\$55,953	\$40,146

Each of the Registrant Subsidiaries qualified pension plans had plan assets in excess of the projected benefit obligation as of December 31, 2025.

Information for each of the Registrant Subsidiaries qualified pension plans with a projected benefit obligation in excess of plan assets as of December 31, 2024 was as follows:

2024	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Projected benefit obligation	\$1,009,496	\$580,451	\$111,659	\$108,354	\$128,652	\$247,186
Fair value of plan assets	\$962,101	\$559,017	\$103,380	\$103,727	\$120,700	\$238,833

Other Postretirement Benefits

Entergy also currently offers retiree medical, dental, vision, and life insurance benefits (other postretirement benefits) for eligible retired employees. Employees who commenced employment before July 1, 2014 and who satisfy certain eligibility requirements (including retiring from Entergy after a certain age and/or years of service with Entergy and immediately commencing their Entergy pension benefit), may become eligible for other postretirement benefits.

In March 2020, Entergy announced changes to its other postretirement benefits. Effective January 1, 2021, certain retired, former non-bargaining employees age 65 and older who are eligible for Entergy-sponsored retiree welfare benefits, and their eligible spouses who are age 65 and older (collectively, Medicare-eligible participants), are eligible to participate in an Entergy-sponsored retiree health plan, and are no longer eligible for retiree coverage under the Entergy Corporation Companies' Benefits Plus Medical, Dental and Vision Plans. Under the Entergy-sponsored retiree health plan, Medicare-eligible participants are eligible to participate in a health reimbursement arrangement which they may use towards the purchase of various types of qualified insurance offered through a Medicare exchange provider and for other qualified medical expenses. The changes affecting active bargaining unit employees were negotiated with the unions prior to implementation, where necessary, and to the extent required by law.

Effective January 1, 1993, Entergy adopted an accounting standard requiring a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. Entergy Arkansas, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy have received regulatory approval to recover accrued other postretirement benefits costs through rates. The LPSC ordered Entergy Louisiana to continue the use of the pay-as-you-go method for ratemaking purposes for postretirement benefits other than pensions. However, the LPSC retains the flexibility to examine individual companies' accounting for other postretirement benefits to determine if special exceptions to this order are warranted. Pursuant to regulatory directives, Entergy Arkansas, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy contribute the other postretirement benefits costs collected in rates into external trusts. System Energy is funding, on behalf of Entergy Operations, other postretirement benefits associated with employees who work or worked at Grand Gulf.

Trust assets contributed by participating Registrant Subsidiaries are in master trusts, established by Entergy Corporation and maintained by a trustee. Each plan has an undivided beneficial interest in each of the investment accounts in its respective master trust that is maintained by a trustee. Each participating Registrant Subsidiary holds a beneficial interest in the plans' investment accounts. The assets in the master trusts are commingled for investment and administrative purposes. Although assets are commingled, supporting records are maintained for the purpose of allocating the beneficial interest in net earnings/(losses) and the administrative expenses of the investment accounts to the various participating plans and participating Registrant Subsidiaries. Beneficial interest in an investment account's net income/(loss) is comprised of interest and dividends, realized and unrealized gains and losses, and expenses. Beneficial interest from these investments is allocated to the plans and participating Registrant Subsidiary based on their portion of net assets in the pooled accounts.

Components of Net Other Postretirement Benefit Cost and Other Amounts Recognized as a Regulatory Asset and/or AOCI

Total 2025, 2024, and 2023 other postretirement benefits (income) costs of the Registrant Subsidiaries, including amounts capitalized and deferred, for their current and former employees included the following components:

2025	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Other postretirement costs:						
Service cost - benefits earned during the period	\$2,286	\$2,606	\$647	\$168	\$634	\$697
Interest cost on APBO	7,099	7,888	1,955	904	2,326	1,576
Expected return on assets	(16,901)	—	(5,310)	(5,020)	(9,806)	(2,808)
Amortization of prior service cost (credit)	2,097	(4,545)	(955)	(798)	(4,371)	(293)
Recognized net (gain) loss	(1,412)	(6,622)	(229)	(220)	613	(27)
Settlement credit	—	(1,014)	—	(1,345)	—	—
Curtailed credit	—	(1,094)	—	(268)	—	—
Asset transfer (gain) loss	—	(2,831)	—	18,908	—	—
Net other postretirement benefits (income) cost	(\$6,831)	(\$5,612)	(\$3,892)	\$12,329	(\$10,604)	(\$855)
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net (gain) loss	(\$2,921)	\$22,730	(\$1,144)	(\$4,037)	(\$8,005)	\$2,656
Amounts reclassified from regulatory asset and/or AOCI to net periodic benefit cost in the current year:						
Amortization of prior service credit (cost)	(2,097)	4,545	955	798	4,371	293
Acceleration of prior service credit due to curtailment	—	1,094	—	268	—	—
Settlement credit	—	1,014	—	1,345	—	—
Amortization of net gain (loss)	1,412	6,622	229	220	(613)	27
Total	(\$3,606)	\$36,005	\$40	(\$1,406)	(\$4,247)	\$2,976
Total recognized as net periodic other postretirement benefits (income) cost, regulatory asset, and/or AOCI (before tax)	(\$10,437)	\$30,393	(\$3,852)	\$10,923	(\$14,851)	\$2,121

2024	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Other postretirement costs:						
Service cost - benefits earned during the period	\$2,569	\$2,800	\$736	\$205	\$670	\$699
Interest cost on APBO	7,331	7,995	1,945	1,012	2,411	1,593
Expected return on assets	(17,535)	—	(5,486)	(5,915)	(10,156)	(2,912)
Amortization of prior service cost (credit)	2,097	(4,544)	(955)	(916)	(4,371)	(293)
Recognized net (gain) loss	—	(6,952)	61	74	591	—
Net other postretirement benefits income	(\$5,538)	(\$701)	(\$3,699)	(\$5,540)	(\$10,855)	(\$913)
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net gain	(\$20,074)	(\$7,273)	(\$3,915)	(\$2,217)	(\$4,683)	(\$3,476)

Amounts reclassified from regulatory asset and/or AOCI to net periodic benefit cost in the current year:

Amortization of prior service credit (cost)	(2,097)	4,544	955	916	4,371	293
Amortization of net gain (loss)	—	6,952	(61)	(74)	(591)	—
Total	(\$22,171)	\$4,223	(\$3,021)	(\$1,375)	(\$903)	(\$3,183)
Total recognized as net periodic other postretirement (income) cost, regulatory asset, and/or AOCI (before tax)	(\$27,709)	\$3,522	(\$6,720)	(\$6,915)	(\$11,758)	(\$4,096)

2023	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Other postretirement costs:						
Service cost - benefits earned during the period	\$2,965	\$3,379	\$878	\$235	\$809	\$754
Interest cost on APBO	8,002	8,931	2,170	1,160	2,597	1,726
Expected return on assets	(15,113)	—	(4,716)	(5,263)	(8,776)	(2,535)
Amortization of prior service cost (credit)	2,096	(3,804)	(955)	(916)	(4,371)	(293)
Recognized net (gain) loss	171	(7,057)	85	466	914	—
Net other postretirement benefits (income) cost	(\$1,879)	\$1,449	(\$2,538)	(\$4,318)	(\$8,827)	(\$348)
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Prior service credit for the period	\$—	(\$4,434)	\$—	\$—	\$—	\$—
Net gain	(23,033)	(458)	(6,883)	(7,606)	(8,790)	(3,942)
Amounts reclassified from regulatory asset and/or AOCI to net periodic benefit cost in the current year:						
Amortization of prior service credit (cost)	(2,096)	3,804	955	916	4,371	293
Amortization of net gain (loss)	(171)	7,057	(85)	(466)	(914)	—
Total	(\$25,300)	\$5,969	(\$6,013)	(\$7,156)	(\$5,333)	(\$3,649)
Total recognized as net periodic other postretirement (income) cost, regulatory asset, and/or AOCI (before tax)	(\$27,179)	\$7,418	(\$8,551)	(\$11,474)	(\$14,160)	(\$3,997)

Other Postretirement Benefit Obligations, Plan Assets, Funded Status, and Amounts Not Yet Recognized and Recognized in the Balance Sheet

Other postretirement benefits obligations, plan assets, funded status, and amounts not yet recognized and recognized in the Balance Sheets of the Registrant Subsidiaries as of December 31, 2025 and 2024 are as follows:

2025	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in APBO						
Balance at January 1	\$138,212	\$156,831	\$38,143	\$19,701	\$45,609	\$30,553
Service cost	2,286	2,606	647	168	634	697
Interest cost	7,099	7,888	1,955	904	2,326	1,576
Settlement liability transfer	—	(2,831)	—	(4,161)	—	—
Plan participant contributions	3,661	5,450	972	411	913	1,061
Actuarial (gain) loss	10,928	22,730	3,274	595	(1,105)	4,785
Benefits paid	(14,340)	(21,210)	(4,197)	(1,997)	(6,215)	(3,891)
Medicare Part D subsidy received	29	56	6	3	11	14
Balance at December 31	\$147,875	\$171,520	\$40,800	\$15,624	\$42,173	\$34,795
Change in Plan Assets						
Fair value of assets at January 1	\$284,095	\$—	\$89,144	\$105,600	\$167,744	\$46,997
Actual return on plan assets	30,750	—	9,728	9,652	16,706	4,937
Employer contributions	1,080	15,760	223	97	(171)	1,226
Plan participant contributions	3,661	5,450	972	411	913	1,061
Transfer	—	—	—	(23,069)	—	—
Benefits paid	(14,340)	(21,210)	(4,197)	(1,997)	(6,215)	(3,891)
Fair value of assets at December 31	\$305,246	\$—	\$95,870	\$90,694	\$178,977	\$50,330
Funded status	\$157,371	(\$171,520)	\$55,070	\$75,070	\$136,804	\$15,535
Amounts recognized in the balance sheet						
Non-current assets	\$157,371	\$—	\$55,070	\$75,070	\$136,804	\$15,535
Current liabilities	—	(14,140)	—	—	—	—
Non-current liabilities	—	(157,380)	—	—	—	—
Total funded status	\$157,371	(\$171,520)	\$55,070	\$75,070	\$136,804	\$15,535
Amounts recognized in regulatory asset						
Prior service cost (credit)	\$789	\$—	(\$772)	\$—	(\$3,048)	\$90
Net loss (gain)	(39,563)	—	(9,706)	(10,606)	650	(681)
	(\$38,774)	\$—	(\$10,478)	(\$10,606)	(\$2,398)	(\$591)
Amounts recognized in AOCI (before tax)						
Prior service credit	\$—	(\$2,462)	\$—	\$—	\$—	\$—
Net gain	—	(45,664)	—	—	—	—
	\$—	(\$48,126)	\$—	\$—	\$—	\$—

2024	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)		
Change in APBO						
Balance at January 1	\$155,987	\$170,139	\$41,344	\$21,685	\$51,617	\$33,778
Service cost	2,569	2,800	736	205	670	699
Interest cost	7,331	7,995	1,945	1,012	2,411	1,593
Plan participant contributions	4,200	5,867	696	519	681	1,297
Actuarial gain	(17,007)	(7,273)	(3,008)	(1,063)	(3,763)	(2,897)
Benefits paid	(14,917)	(22,774)	(3,584)	(2,658)	(6,021)	(3,934)
Medicare Part D subsidy received	49	77	14	1	14	17
Balance at December 31	\$138,212	\$156,831	\$38,143	\$19,701	\$45,609	\$30,553
Change in Plan Assets						
Fair value of assets at January 1	\$274,814	\$—	\$85,662	\$100,536	\$161,318	\$45,402
Actual return on plan assets	20,602	—	6,393	7,069	11,076	3,491
Employer contributions	(604)	16,907	(23)	134	690	741
Plan participant contributions	4,200	5,867	696	519	681	1,297
Benefits paid	(14,917)	(22,774)	(3,584)	(2,658)	(6,021)	(3,934)
Fair value of assets at December 31	\$284,095	\$—	\$89,144	\$105,600	\$167,744	\$46,997
Funded status	\$145,883	(\$156,831)	\$51,001	\$85,899	\$122,135	\$16,444
Amounts recognized in the balance sheet						
Non-current assets	\$145,883	\$—	\$51,001	\$85,899	\$122,135	\$16,444
Current liabilities	—	(14,377)	—	—	—	—
Non-current liabilities	—	(142,454)	—	—	—	—
Total funded status	\$145,883	(\$156,831)	\$51,001	\$85,899	\$122,135	\$16,444
Amounts recognized in regulatory asset						
Prior service cost (credit)	\$2,886	\$—	(\$1,727)	(\$1,066)	(\$7,419)	(\$203)
Net loss (gain)	(38,054)	—	(8,791)	(8,134)	9,268	(3,364)
	(\$35,168)	\$—	(\$10,518)	(\$9,200)	\$1,849	(\$3,567)
Amounts recognized in AOCI (before tax)						
Prior service credit	\$—	(\$8,101)	\$—	\$—	\$—	\$—
Net gain	—	(76,030)	—	—	—	—
	\$—	(\$84,131)	\$—	\$—	\$—	\$—

The other postretirement plans incurred net actuarial losses during 2025 primarily due to liability losses resulting from revisions to retiree life assumptions and a fall in bond yields that resulted in decreases to the discount rates used to develop the benefit obligations, partially offset by asset gains due to an actual return on assets higher than the expected return on assets. The other postretirement plans incurred net actuarial gains during 2024 primarily due to liability gains due to a rise in bond yields that resulted in increases to the discount rates used to develop the benefit obligations and an actual return on assets higher than the expected return on assets.

Non-Qualified Pension Plans

Entergy also sponsors non-qualified, non-contributory defined benefit pension plans that provide benefits to certain key employees.

The following Registrant Subsidiaries participate in Entergy's non-qualified, non-contributory defined benefit pension plans that provide benefits to certain key employees. The net periodic pension cost for their current and former employees for the non-qualified plans for 2025, 2024, and 2023, was as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
2025	\$184	\$140	\$558	\$137	\$157
2024	\$269	\$256	\$326	\$122	\$248
2023	\$637	\$99	\$808	\$132	\$253

Included in the 2023 net periodic pension cost above are settlement charges of \$379 thousand for Entergy Arkansas related to the lump sum benefits paid out of the plan.

The projected benefit obligation for their current and former employees for the non-qualified plans as of December 31, 2025 and 2024 was as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
2025	\$2,105	\$1,886	\$3,858	\$1,335	\$2,844
2024	\$1,721	\$1,405	\$3,566	\$1,143	\$2,734

The accumulated benefit obligation for their current and former employees for the non-qualified plans as of December 31, 2025 and 2024 was as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
2025	\$1,654	\$1,299	\$3,464	\$1,163	\$2,832
2024	\$1,468	\$1,197	\$3,322	\$939	\$2,710

The following amounts were recorded on the balance sheet as of December 31, 2025 and 2024:

2025	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
Current liabilities		(\$538)	(\$191)	(\$344)	(\$95)
Non-current liabilities		(1,567)	(1,695)	(3,514)	(1,240)
Total funded status		(\$2,105)	(\$1,886)	(\$3,858)	(\$1,335)
Regulatory asset (liability)		\$441	\$1,079	\$1,764	\$81
Accumulated other comprehensive income (before taxes)		\$—	\$45	\$—	\$—

2024	Energy Arkansas	Energy Louisiana	Energy Mississippi	Energy New Orleans	Energy Texas
			(In Thousands)		
Current liabilities	(\$524)	(\$190)	(\$419)	(\$104)	(\$386)
Non-current liabilities	(1,197)	(1,215)	(3,147)	(1,039)	(2,348)
Total funded status	(\$1,721)	(\$1,405)	(\$3,566)	(\$1,143)	(\$2,734)
Regulatory asset (liability)	\$119	\$493	\$1,292	\$9	(\$3,429)
Accumulated other comprehensive income (before taxes)	\$—	\$21	\$—	\$—	\$—

The non-qualified plans incurred an actuarial loss during 2025 primarily as a result of liability losses due to salary increases in excess of expectations, as well as a decline in bond yields that resulted in decreases to the discount rate used to develop the benefit obligations. The non-qualified pension plans incurred an actuarial loss during 2024 primarily as a result of liability losses due to differences in recent retirement and lump sum experience relative to actuarial assumptions, as well as salary increases in excess of expectations.

Accounting for Pension and Other Postretirement Benefits

Qualified Pension Settlement Costs

The Entergy Corporation Retirement Plan for Bargaining Employees and the Entergy Corporation Retirement Plan for Non-Bargaining Employees were remeasured with the sale of the Entergy Louisiana and Entergy New Orleans natural gas distribution businesses on July 1, 2025, resulting in settlement charges of \$12.1 million as a result of ongoing payments of lump sum benefits from the plans and settlement charges of \$11.8 million as a result of the sale. Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy each participate in one or both of the Entergy Corporation Retirement Plan for Bargaining Employees and the Entergy Corporation Retirement Plan for Non-Bargaining Employees and incurred settlement costs.

In May 2024, Entergy Corporation entered into a commitment agreement by and between Entergy Corporation, Newport Trust Company, LLC, as independent fiduciary of Entergy Corporation Retirement Plan II for Non-Bargaining Employees, Entergy Corporation Retirement Plan II for Bargaining Employees, Entergy Corporation Retirement Plan III, and Entergy Corporation Retirement Plan IV for Bargaining Employees (the Pension Plans), and the Metropolitan Life Insurance Company (MetLife), under which the Pension Plans purchased a nonparticipating single premium group annuity contract from MetLife to settle approximately \$1.2 billion of benefit liabilities of the Pension Plans.

The group annuity contract primarily covers a population that includes approximately 3,400 non-utility business retirees, joint annuitants, beneficiaries, and alternate payees who commenced benefit payments from the Pension Plans on or before March 1, 2024 (Transferred Participants). MetLife irrevocably guarantees and assumes the sole obligation to make future monthly pension benefit payments to the Transferred Participants as provided under its group annuity contract, with direct payments that began September 1, 2024. The aggregate amount of each Transferred Participant's payment under the group annuity contract will be equal to the amount of each individual's payment under the Pension Plans.

The purchase of the group annuity contract was funded directly by assets of the Pension Plans. The transferred pension liability required no additional funding prior to transfer, as the liability was fully funded. As a result of the transaction, Entergy recognized a one-time non-cash pension settlement charge of \$328 million in 2024, of which \$8 million was recorded at Utility, as described below, and \$320 million was recorded at Parent & Other. The \$320 million settlement charge at Parent & Other is reflected in Miscellaneous - net in Other income (deductions) on the consolidated income statements.

Year-to-date lump sum benefit payments from Non-Bargaining Plan I, Bargaining Plan I, Non-Bargaining Plan II, and Bargaining Plan II exceeded the sum of the Plans' service and interest cost, resulting in settlement costs during 2023. Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy participate in one or both of Non-Bargaining Plan I and Bargaining Plan I and incurred settlement costs.

In accordance with accounting standards, settlement accounting requires immediate recognition of the portion of previously unrecognized losses associated with the settled portion of the plan's pension liability. Similar to other pension costs, the settlement costs were included with employee labor costs and charged to expense and capital in the same manner that labor costs were charged. Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans each received regulatory approval to defer the expense portion of settlement costs, with future amortization of the deferred settlement expense over the period in which the expense otherwise would be recorded had the immediate recognition not occurred.

Qualified Pension and Other Postretirement Plans' Assets

The Plan Administrator's trust asset investment strategy is to invest the assets in a manner whereby long-term earnings on the assets (plus cash contributions) provide adequate funding for retiree benefit payments. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense.

In the optimization studies, the Plan Administrator formulates assumptions about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes. The future market assumptions used in the optimization study are determined by examining historical market characteristics of the various asset classes and making adjustments to reflect future conditions expected to prevail over the study period.

The target asset allocation for pension adjusts dynamically based on the funded status of each plan within the trust. The current targets are shown below. The expectation is that the allocation to fixed income securities will increase as the pension plans' funded status increases. The following ranges were established to produce an acceptable, economically efficient plan to manage around the targets.

For postretirement assets the target and range asset allocations (as shown below) reflect recommendations made in the latest optimization study. The target asset allocations for postretirement assets adjust dynamically based on the funded status of each sub-account within each trust. The current weighted-average targets shown below represent the aggregate of all targets for all sub-accounts within all trusts.

Entergy's qualified pension and postretirement weighted-average asset allocations by asset category at December 31, 2025 and 2024 and the target asset allocation and ranges for 2025 are as follows:

Pension Asset Allocation	Target		Range		Actual 2025		Actual 2024	
	Domestic Equity Securities	19%	10%	to	22%	19%	23%	
International Equity Securities	11%	7%	to	15%	12%	13%		
Intermediate Fixed Income Securities	4%	3%	to	5%	4%	5%		
Long Duration Fixed Income Securities	66%	62%	to	70%	64%	59%		
Other	—%	—%	to	10%	1%	—%		

Postretirement Asset Allocation	Target		Range		Actual 2025		Actual 2024	
	Domestic Equity Securities	14%	9%	to	19%	16%	16%	
International Equity Securities	9%	4%	to	14%	10%	9%		
Fixed Income Securities	77%	72%	to	82%	74%	75%		
Other	—%	—%	to	5%	—%	—%		

In determining its expected long-term rate of return on plan assets used in the calculation of benefit plan costs, Entergy reviews past performance, current and expected future asset allocations, and capital market assumptions of its investment consultant and some investment managers.

The expected long-term rate of return for the qualified pension plans' assets is based primarily on the geometric average of the historical annual performance of a representative portfolio weighted by the target asset allocation defined in the table above, along with other indications of expected return on assets. The time period reflected is a long-dated period spanning several decades.

The expected long-term rate of return for the non-taxable postretirement trust assets is determined using the same methodology described above for pension assets, but the aggregate asset allocation specific to the non-taxable postretirement assets is used.

For the taxable postretirement trust assets, the investment allocation includes tax-exempt fixed income securities. This asset allocation, in combination with the same methodology employed to determine the expected return for other postretirement assets (as described above), and with a modification to reflect applicable taxes, is used to produce the expected long-term rate of return for taxable postretirement trust assets.

Concentrations of Credit Risk

Entergy's investment guidelines mandate the avoidance of risk concentrations. Types of concentrations specified to be avoided include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, geographic area, and individual security issuance. As of December 31, 2025, all investment managers and assets were materially in compliance with the approved investment guidelines, therefore there were no significant concentrations (defined as greater than 10 percent of plan assets) of credit risk in Entergy's pension and other postretirement benefits plan assets.

Fair Value Measurements

Accounting standards provide the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques 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 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are described below:

- Level 1 - Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in active markets that the Plan has the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 - Level 2 inputs are inputs other than quoted prices included in Level 1 that are, either directly or indirectly, observable for the asset or liability at the measurement date. Assets are valued based on prices derived by an independent party that uses inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads. Prices are reviewed and can be challenged with the independent parties and/or overridden if it is believed such would be more reflective of fair value. Level 2 inputs include the following:
 - quoted prices for similar assets or liabilities in active markets;
 - quoted prices for identical assets or liabilities in inactive markets;
 - inputs other than quoted prices that are observable for the asset or liability; or
 - inputs that are derived principally from or corroborated by observable market data by correlation or other means.

If an asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

- Level 3 - Level 3 refers to securities valued based on significant unobservable inputs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The following tables set forth by level within the fair value hierarchy, measured at fair value on a recurring basis at December 31, 2025, and December 31, 2024, a summary of the investments held in the master trusts for Entergy's qualified pension and other postretirement plans in which the Registrant Subsidiaries participate.

Qualified Defined Benefit Pension Plan Trusts

2025	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Equity securities:				
Corporate stocks:				
Preferred	\$448 (b)	\$—	\$—	\$448
Common	393,885 (b)	—	—	393,885
Common collective trusts (c)				1,136,233
Fixed income securities:				
U.S. Government securities	—	1,628,119 (a)	—	1,628,119
Corporate debt instruments	—	413,001 (a)	—	413,001
Registered investment companies (e)	27,905 (d)	2,921 (d)	—	1,546,320
Other	—	54,553 (f)	—	54,553
Other:				
Insurance company general account (unallocated contracts)	—	6,058 (g)	—	6,058
Total investments	\$422,238	\$2,104,652	\$—	\$5,178,617
Cash				4,181
Other pending transactions				(314,791)
Less: Other postretirement assets included in total investments				(69,043)
Total fair value of qualified pension assets				\$4,798,964

2024	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Equity securities:				
Corporate stocks:				
Preferred	\$932 (b)	\$—	\$—	\$932
Common	403,146 (b)	—	—	403,146
Common collective trusts (c)				1,206,983
Fixed income securities:				
U.S. Government securities	—	1,145,994 (a)	—	1,145,994
Corporate debt instruments	—	307,666 (a)	—	307,666
Registered investment companies (e)	30,293 (d)	2,735 (d)	—	1,512,994
Other	—	44,691 (f)	—	44,691
Other:				
Insurance company general account (unallocated contracts)	—	5,918 (g)	—	5,918
Total investments	\$434,371	\$1,507,004	\$—	\$4,628,324
Cash				2,026
Other pending transactions				(133,550)
Less: Other postretirement assets included in total investments				(64,068)
Total fair value of qualified pension assets				\$4,432,732

Other Postretirement Trusts

2025	Level 1		Level 2		Level 3	Total
			(In Thousands)			
Equity securities:						
Common collective trust (c)						\$169,496
Fixed income securities:						
U.S. Government securities	\$141,859	(b)	\$108,977	(a)	\$—	250,836
Corporate debt instruments	—		161,171	(a)	—	161,171
Registered investment companies	2,412	(d)	—		—	2,412
Other	—		70,547	(f)	—	70,547
Total investments	\$144,271		\$340,695		\$—	\$654,462
Other pending transactions						2,512
Plus: Other postretirement assets included in the investments of the qualified pension trust						69,043
Total fair value of other postretirement assets						\$726,017

2024	Level 1		Level 2		Level 3	Total
			(In Thousands)			
Equity securities:						
Common collective trust (c)						\$161,726
Fixed income securities:						
U.S. Government securities	\$107,547	(b)	\$112,780	(a)	\$—	220,327
Corporate debt instruments	—		166,208	(a)	—	166,208
Registered investment companies	2,295	(d)	—		—	2,295
Other	—		80,561	(f)	—	80,561
Total investments	\$109,842		\$359,549		\$—	\$631,117
Other pending transactions						3,417
Plus: Other postretirement assets included in the investments of the qualified pension trust						64,068
Total fair value of other postretirement assets						\$698,602

- a. Certain fixed income debt securities (corporate, government, and securitized) are stated at fair value as determined by broker quotes.
- b. Common stocks, preferred stocks, and certain fixed income debt securities (government) are stated at fair value determined by quoted market prices.
- c. The common collective trusts hold investments in accordance with stated objectives. The investment strategy of the trusts is to capture the growth potential of equity markets by replicating the performance of a specified index. The issuer of these funds allows daily trading at the net asset value and trades settle at a later date, with no other trading restrictions. Net asset value per share of common collective trusts estimate fair value. Common collective trusts are not publicly quoted and are valued by the fund administrators using net asset value as a practical expedient. Accordingly, these funds are not assigned a level in the fair value table, but are included in the total.
- d. Registered investment companies are money market mutual funds with a stable net asset value of one dollar per share. Registered investment companies may hold investments in domestic and international bond markets or domestic equities valued at the daily closing price as reported by the fund. These funds are required to publish their daily net asset value and to transact at that price. The money market mutual funds held by the trusts are deemed to be actively traded. Certain registered investment companies are recorded at contract value, which approximates fair value.
- e. Certain of these registered investment companies are not publicly quoted and are valued by the fund administrators using net asset value as a practical expedient. The issuer of these funds allows daily trading at the net asset value and trades settle at a later date, with no other trading restrictions. Accordingly, these funds are not assigned a level in the fair value table, but are included in the total.
- f. The other remaining assets are U.S. municipal and foreign government bonds stated at fair value as determined by broker quotes.
- g. The unallocated insurance contract investments are recorded at contract value, which approximates fair value. The contract value represents contributions made under the contract, plus interest, less funds used to pay benefits and contract expenses, and less distributions to the master trust.

Estimated Future Benefit Payments

Based upon the assumptions used to measure Entergy's qualified pension and other postretirement benefits obligations at December 31, 2024, and including pension and other postretirement benefits attributable to estimated future employee service, Entergy expects that benefits to be paid over the next ten years for the Registrant Subsidiaries for their current and former employees will be as follows:

Estimated Future Qualified Pension Benefits Payments	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Year(s)						
2026	\$93,808	\$99,918	\$26,878	\$9,197	\$22,960	\$25,290
2027	\$91,254	\$93,767	\$26,048	\$9,077	\$21,128	\$23,750
2028	\$90,558	\$93,224	\$25,693	\$8,802	\$20,459	\$22,987
2029	\$89,116	\$91,966	\$25,798	\$8,668	\$20,023	\$23,243
2030	\$89,462	\$91,351	\$24,871	\$8,434	\$19,230	\$22,668
2031 - 2035	\$436,323	\$448,573	\$117,545	\$40,445	\$90,024	\$110,793

Estimated Future Non-Qualified Pension Benefits Payments	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
Year(s)					
2026	\$538	\$191	\$344	\$95	\$390
2027	\$104	\$176	\$875	\$304	\$364
2028	\$197	\$163	\$673	\$246	\$339
2029	\$164	\$160	\$508	\$198	\$313
2030	\$157	\$142	\$1,465	\$662	\$287
2031 - 2035	\$893	\$891	\$284	\$61	\$1,100

Year(s)	Estimated Future Other Postretirement Benefits Payments	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
2026		\$11,587	\$14,140	\$3,187	\$1,610	\$3,915	\$2,499
2027		\$11,331	\$13,710	\$3,132	\$1,509	\$3,746	\$2,434
2028		\$11,203	\$13,257	\$3,156	\$1,400	\$3,563	\$2,411
2029		\$11,189	\$12,947	\$3,105	\$1,322	\$3,413	\$2,437
2030		\$11,156	\$12,772	\$3,073	\$1,270	\$3,399	\$2,462
2031 - 2035		\$56,327	\$63,275	\$15,314	\$5,779	\$15,729	\$12,685

Contributions

The Registrant Subsidiaries currently expect to contribute the following approximate amounts to their qualified pension and other postretirement plans for their current and former employees in 2026:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
			(In Thousands)			
Pension Contributions	\$29,716	\$41,599	\$3,991	\$3,304	\$5,931	\$13,249
Other Postretirement Contributions	\$710	\$14,140	\$176	\$336	\$149	\$49

The 2026 required pension contributions will be known with more certainty when the January 1, 2026 valuations are completed, which is expected by April 1, 2026.

Actuarial Assumptions

The significant actuarial assumptions used in determining the pension PBO and the other postretirement benefits APBO as of December 31, 2025 and 2024 were as follows:

	2025	2024
Weighted-average discount rate:		
Qualified pension	5.51% - 5.94%	5.67% - 5.89%
Other postretirement	Blended 5.65%	Blended 5.75%
Non-qualified pension	5.50%	5.66%
Weighted-average rate of increase in future compensation levels	4.82%	5.23%
Interest crediting rate	3.98% - 4.45%	3.98% - 4.45%
Assumed health care trend rate:	4.80%	4.80%
Pre-65	8.50%	8.15%
Post-65	10.63%	10.13%
Ultimate health care cost trend rate	4.75%	4.75%
Year ultimate health care cost trend rate is reached and beyond:		
Pre-65	2036	2035
Post-65	2036	2035

The significant actuarial assumptions used in determining the net periodic pension and other postretirement benefits costs for 2025, 2024, and 2023 were as follows:

	2025	2024	2023
Weighted-average discount rate:			
Qualified pension:			
Service cost	5.75%	5.08%	5.26%
Interest cost	5.46%	4.97%	5.16%
Other postretirement:			
Service cost	5.50%	4.82%	5.00%
Interest cost	5.36%	4.91%	5.09%
Non-qualified pension:			
Service cost	4.83%	5.01%	5.31%
Interest cost	4.44%	4.86%	5.30%
Weighted-average rate of increase in future compensation levels	3.98% - 4.45%	3.98% - 4.40%	3.98% - 4.40%
Expected long-term rate of return on plan assets:			
Pension assets	6.00% - 7.00%	6.00% - 7.25%	7.00%
Other postretirement non-taxable assets	Blended 6.75%	Blended 6.75%	
Other postretirement taxable assets	6.00% - 7.00%	6.50% - 7.25%	6.00% - 7.00%
Assumed health care trend rate:	4.75%	5.25%	5.25%
Pre-65	8.15%	6.95%	6.65%
Post-65	10.13%	7.88%	7.50%
Ultimate health care cost trend rate	4.75%	4.75%	4.75%
Year ultimate health care cost trend rate is reached and beyond:			
Pre-65	2035	2032	2032
Post-65	2035	2032	2032

With respect to the mortality assumptions, Entergy used the Pri-2012 Employee and Healthy Annuitant Table, projected generationally using Scale MP-2021 with Aon's Endemic Adjustment, in determining its December 31, 2025 and 2024 pension plans' PBOs and other postretirement benefits' APBO.

Defined Contribution Plans

Entergy sponsors the Savings Plan of Entergy Corporation and Subsidiaries (System Savings Plan). The System Savings Plan is a defined contribution plan covering eligible employees of Entergy and certain of its subsidiaries. The participating Entergy subsidiary makes matching contributions to the System Savings Plan for all eligible participating employees in an amount equal to either 70% or 100% of the participants' basic contributions, up to 6% of their eligible earnings per pay period. The matching contribution is allocated to investments as directed by the employee.

Entergy sponsored the Savings Plan of Entergy Corporation and Subsidiaries VI (Savings Plan VI) (established in April 2007) and the Savings Plan of Entergy Corporation and Subsidiaries VII (Savings Plan VII) (established in April 2007) to which matching contributions were made. The plans were defined contribution plans that covered eligible employees, as defined by each plan, of Entergy and certain of its subsidiaries. Effective December 31, 2023, employees participating in Savings Plan VI and Savings Plan VII were transferred into the System Savings Plan when Savings Plan VI and Savings Plan VII merged into the System Savings Plan.

Entergy also sponsors the Savings Plan of Entergy Corporation and Subsidiaries VIII (established January 2021) and the Savings Plan of Entergy Corporation and Subsidiaries IX (established January 2021) to which company contributions are made. The participating Entergy subsidiary makes matching contributions to these defined contribution plans for all eligible participating employees in an amount equal to 100% of the participants' basic contributions, up to 5% of their eligible earnings per pay period. Eligible participants may also receive a discretionary annual company contribution up to 4% of the participant's eligible earnings (subject to vesting).

The Registrant Subsidiaries' 2025, 2024, and 2023 contributions to defined contribution plans for their employees were as follows:

Year	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)		
2025	\$7,550	\$9,529	\$4,524	\$1,555	\$4,385
2024	\$6,822	\$8,784	\$4,048	\$1,584	\$3,907
2023	\$5,866	\$7,757	\$3,534	\$1,383	\$3,380

NOTE 12. STOCK-BASED COMPENSATION

Note 12 to the financial statements is not applicable to the Registrant Subsidiaries.

NOTE 13. BUSINESS SEGMENT INFORMATION

Registrant Subsidiaries

Entergy Arkansas has one operating and reportable segment, an integrated utility business which includes the generation, transmission, and distribution of electric power. Revenue for each integrated utility business is primarily derived from retail electric sales. Each of the Registrant Subsidiaries' operations are managed on an integrated basis by that company because of the substantial effect of cost-based rates and regulatory oversight on the business process, cost structures, and operating results. The chief operating decision maker for the Registrant Subsidiaries is the respective president and chief executive officer for the Utility operating companies and the president for System Energy. Each chief operating decision maker assesses financial performance on an entity-wide basis and decides how to allocate resources based on net income that also is reported on the income statement for each of the Registrant Subsidiaries as net income. Net income is used in the annual planning process and to monitor budget versus actual results on a monthly basis and each Registrant Subsidiary's earned return on common equity in assessing financial performance. Each chief operating decision maker is only provided with the consolidated financial results for the respective Registrant Subsidiary. All segment financial information for the Registrant Subsidiaries is as reported on the respective financial statements for each of the Registrant Subsidiaries.

NOTE 14. ACQUISITIONS AND DISPOSITIONS

Acquisitions

Walnut Bend Solar

In June 2020, Entergy Arkansas signed a build-own-transfer agreement for the purchase of an approximately 100 MW to-be-constructed solar photovoltaic energy facility, Walnut Bend Solar facility, to be sited on approximately 1,000 acres in Lee County, Arkansas. Acquisition of the Walnut Bend Solar facility was initially approved by the APSC in July 2021. The agreement was amended by the parties in February 2023, and the revised agreement was approved by the APSC in July 2023. In February 2024, Entergy Arkansas made an initial payment of approximately \$170 million to acquire the facility. Substantial completion was achieved and commercial operation commenced in September 2024, at which time Entergy Arkansas made a substantial completion payment of approximately \$16 million for acquisition of the facility. The final payment of approximately \$1 million for the acquisition of the facility was made in March 2025.

West Memphis Solar

In September 2020, Entergy Arkansas signed a build-own-transfer agreement for the purchase of an approximately 180 MW to-be-constructed solar photovoltaic energy facility, West Memphis Solar facility, to be sited on approximately 1,500 acres in Crittenden County, Arkansas. Acquisition of the West Memphis Solar facility was initially approved by the APSC in October 2021. In March 2022 the counterparty to the build-own-transfer agreement notified Entergy Arkansas that it was seeking changes to certain terms of the agreement, including both cost and schedule. Entergy Arkansas filed a supplemental application with the APSC in January 2023 for a change in the transmission route and updates to the cost and schedule, which was approved by the APSC in March 2023. In August 2024, Entergy Arkansas made an initial payment of approximately \$48 million to acquire the facility. Substantial completion was achieved in November 2024, at which time Entergy Arkansas made a substantial completion payment of approximately \$192 million for acquisition of the facility. Commercial operation commenced in December 2024.

Driver Solar

In August 2022, Entergy Arkansas signed a build-own-transfer agreement for the purchase of an approximately 250 MW to-be-constructed solar photovoltaic energy facility, Driver Solar facility, to be sited near Osceola, Arkansas. Acquisition of the Driver Solar facility was approved by the APSC in August 2022. In August 2024, Entergy Arkansas made an initial payment of approximately \$308 million to acquire the facility. Substantial completion was achieved in November 2024, at which time Entergy Arkansas made a substantial completion payment of approximately \$85 million for acquisition of the facility. Commercial operation commenced in December 2024. The final payment of approximately \$0.3 million for the acquisition of the facility was made in April 2025.

NOTE 15. RISK MANAGEMENT AND FAIR VALUES

Market Risk

In the normal course of business, Entergy is exposed to a number of market risks. Market risk is the potential loss that Entergy may incur as a result of changes in the market or fair value of a particular commodity or instrument. All financial and commodity-related instruments, including derivatives, are subject to market risk including commodity price risk, equity price, and interest rate risk. Entergy uses derivatives primarily to mitigate commodity price risk associated with the price of fuel and to mitigate interest rate exposure related to certain financing agreements.

The Utility has limited exposure to the effects of market risk because it operates primarily under cost-based rate regulation. To the extent approved by their retail regulators, the Utility operating companies use commodity and financial instruments to hedge the exposure to price volatility inherent in their purchased power, fuel, and gas purchased for resale costs, that are recovered from customers.

Derivatives

Entergy designates a significant portion of its derivative instruments as normal purchase/normal sale transactions due to their physical settlement provisions, including power purchase and sales agreements, fuel purchase agreements, and capacity contracts. Certain derivative instruments do not qualify for designation as normal purchase/normal sale transactions due to their financial settlement provisions. See further discussion below regarding these derivative instruments.

During the second quarter 2025, Entergy participated in the annual financial transmission rights auction process for the MISO planning year of June 1, 2025 through May 31, 2026. Financial transmission rights are derivative instruments that represent economic hedges of future congestion charges that will be incurred in serving Entergy's customer load. They are not designated as hedging instruments. Entergy initially records financial transmission rights at their estimated fair value and subsequently adjusts the carrying value to their estimated fair value at the end of each accounting period prior to settlement. Unrealized gains or losses on financial transmission rights held by the non-utility operations are included in operating revenues. The Utility operating companies recognize regulatory liabilities or assets for unrealized gains or losses on financial transmission rights. The total volume of financial transmission rights outstanding as of December 31, 2025 is 9,504 GWh for Entergy Arkansas, 23,971 GWh for Entergy Louisiana, 5,070 GWh for Entergy Mississippi, 1,637 GWh for Entergy New Orleans, and 4,714 GWh for Entergy Texas. Credit support for financial transmission rights held by the Utility operating companies is covered by cash and/or letters of credit issued by each Utility operating company as required by MISO. No cash was required to be posted for financial transmission rights exposure for the Utility operating companies as of December 31, 2025 and 2024. Letters of credit posted with MISO covered the financial transmission rights exposure for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy Texas as of December 31, 2025 and for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas as of December 31, 2024. Credit support for financial transmission rights held by Entergy's non-utility operations business may also be covered by cash and/or letters of credit. No cash or letters of credit were required to be posted for financial transmission rights exposure for the non-utility operations business as of December 31, 2025 and 2024.

The fair values of derivative instruments not designated as hedging instruments on the Registrant Subsidiaries' balance sheets as of December 31, 2025 and 2024 are shown in the tables below. Certain investments, including those not designated as hedging instruments, are subject to master netting agreements and are presented in the balance sheet on a net basis in accordance with accounting guidance for derivatives and hedging.

Instrument	Balance Sheet Location	Gross Fair Value (a)	Offsetting Position (b) (In Millions)	Net Fair Value (c) (d)	Registrant
2025					
Assets:					
Financial transmission rights	Prepayments and other	\$5.5	\$—	\$5.5	Entergy Arkansas
Financial transmission rights	Prepayments and other	\$16.8	(\$0.1)	\$16.7	Entergy Louisiana
Financial transmission rights	Prepayments and other	\$0.4	\$—	\$0.4	Entergy Mississippi
Financial transmission rights	Prepayments and other	\$1.8	\$—	\$1.8	Entergy New Orleans
Financial transmission rights	Prepayments and other	\$2.3	(\$0.2)	\$2.1	Entergy Texas
Interest rate swaps	Prepayments and other	\$0.5	\$—	\$0.5	Entergy Texas
Liabilities:					
Natural gas swaps	Other current liabilities	\$5.3	\$—	\$5.3	Entergy Mississippi
Interest rate swaps	Other non-current liabilities	\$3.0	\$—	\$3.0	Entergy Texas
2024					
Assets:					
Natural gas swaps	Prepayments and other	\$1.6	\$—	\$1.6	Entergy Mississippi
Financial transmission rights	Prepayments and other	\$8.6	(\$0.1)	\$8.5	Entergy Arkansas
Financial transmission rights	Prepayments and other	\$8.7	(\$0.1)	\$8.6	Entergy Louisiana
Financial transmission rights	Prepayments and other	\$1.3	\$—	\$1.3	Entergy New Orleans
Financial transmission rights	Prepayments and other	\$2.0	(\$0.1)	\$1.9	Entergy Texas
Liabilities:					
Financial transmission rights	Other current liabilities	(\$0.4)	\$0.9	\$0.5	Entergy Mississippi

a. Represents the gross amounts of recognized assets/liabilities

b. Represents the netting of fair value balances with the same counterparty

c. Represents the net amounts of assets/liabilities presented on the Registrant Subsidiaries' balance sheets

d. Excludes letters of credit posted with MISO to cover financial transmission rights exposure in the amount of \$0.1 million for Entergy Arkansas, \$0.8 million for Entergy Louisiana, \$0.8 million for Entergy Mississippi, and \$0.1 million for Entergy Texas as of December 31, 2025 and in the amount of \$0.5 million for Entergy Arkansas, \$0.1 million for Entergy Louisiana, \$0.8 million for Entergy Mississippi, \$0.1 million for Entergy New Orleans, and \$0.3 million for Entergy Texas as of December 31, 2024

The effects of derivative instruments not designated as hedging instruments on the Registrant Subsidiaries' income statements for the years ended December 31, 2025, 2024, and 2023 are as follows:

Instrument	Income Statement Location	Amount of gain (loss) recorded in the income statement (In Millions)	Registrant
2025			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a) (\$8.4)	Entergy Mississippi
Financial transmission rights	Purchased power expense	(b) \$51.3	Entergy Arkansas
Financial transmission rights	Purchased power expense	(b) \$101.0	Entergy Louisiana
Financial transmission rights	Purchased power expense	(b) \$11.5	Entergy Mississippi
Financial transmission rights	Purchased power expense	(b) \$15.0	Entergy New Orleans
Financial transmission rights	Purchased power expense	(b) \$15.8	Entergy Texas
Interest rate swaps	Interest expense	(c) (\$2.5)	Entergy Texas
2024			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a) (\$7.0)	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a) (\$0.5)	Entergy New Orleans
Financial transmission rights	Purchased power expense	(b) \$59.8	Entergy Arkansas
Financial transmission rights	Purchased power expense	(b) \$71.7	Entergy Louisiana
Financial transmission rights	Purchased power expense	(b) \$7.5	Entergy Mississippi
Financial transmission rights	Purchased power expense	(b) \$6.9	Entergy New Orleans
Financial transmission rights	Purchased power expense	(b) \$17.8	Entergy Texas
2023			
Natural gas swaps and options	Fuel, fuel-related expenses, and gas purchased for resale	(a) (\$8.4)	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a) (\$42.9)	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a) (\$3.0)	Entergy New Orleans
Financial transmission rights	Purchased power expense	(b) \$25.8	Entergy Arkansas
Financial transmission rights	Purchased power expense	(b) \$60.4	Entergy Louisiana
Financial transmission rights	Purchased power expense	(b) \$13.7	Entergy Mississippi
Financial transmission rights	Purchased power expense	(b) \$6.4	Entergy New Orleans
Financial transmission rights	Purchased power expense	(b) \$17.3	Entergy Texas

a. Due to regulatory treatment, the natural gas swaps and options are marked-to-market through fuel, fuel-related expenses, and gas purchased for resale and then such amounts are simultaneously reversed and recorded as an offsetting regulatory asset or liability. The gains or losses recorded as fuel expenses when the swaps and options are settled are recovered or refunded through fuel cost recovery mechanisms.

b. Due to regulatory treatment, the changes in the estimated fair value of financial transmission rights for the Utility operating companies are recorded through purchased power expense and then such amounts are simultaneously reversed and recorded as an offsetting regulatory asset or liability. The gains or losses recorded as purchased power expense when the financial transmission rights for the Utility operating companies are settled are recovered or refunded through fuel cost recovery mechanisms.

- c. Due to regulatory treatment, the changes in the estimated fair value of the interest rate swaps for Entergy Texas are recorded through interest expense and then such amounts are simultaneously reversed and recorded as an offsetting regulatory asset or liability. The gains or losses recorded as interest expense when the interest rate swaps for Entergy Texas are settled are expected to be recovered in ratemaking relating to the Legend Power Station.

Fair Values

The estimated fair values of Entergy's financial instruments and derivatives are determined using historical prices, bid prices, market quotes, and financial modeling. Considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that Entergy could realize in a current market exchange. Gains or losses realized on financial instruments are reflected in future rates and therefore do not affect net income. Entergy considers the carrying amounts of most financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments.

Accounting standards define fair value as an exit price, or the price that would be received to sell an asset or the amount that would be paid to transfer a liability in an orderly transaction between knowledgeable market participants at the date of measurement. Entergy and the Registrant Subsidiaries use assumptions or market input data that market participants would use in pricing assets or liabilities at fair value. The inputs can be readily observable, corroborated by market data, or generally unobservable. Entergy and the Registrant Subsidiaries endeavor to use the best available information to determine fair value.

Accounting standards establish a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy establishes the highest priority for unadjusted market quotes in an active market for the identical asset or liability and the lowest priority for unobservable inputs.

The three levels of the fair value hierarchy are:

- Level 1 - Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the entity has the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of individually owned common stocks, cash equivalents (temporary cash investments, securitization recovery trust account, and escrow accounts), debt instruments, and gas swaps traded on exchanges with active markets. Cash equivalents includes all unrestricted highly liquid debt instruments with an original or remaining maturity of three months or less at the date of purchase.
- Level 2 - Level 2 inputs are inputs other than quoted prices included in Level 1 that are, either directly or indirectly, observable for the asset or liability at the measurement date. Assets are valued based on prices derived by independent third parties that use inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads. Prices are reviewed and can be challenged with the independent parties and/or overridden by Entergy if it is believed such would be more reflective of fair value. Level 2 inputs include the following:
 - quoted prices for similar assets or liabilities in active markets;
 - quoted prices for identical assets or liabilities in inactive markets;
 - inputs other than quoted prices that are observable for the asset or liability; or
 - inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 2 consists primarily of individually-owned debt instruments, gas swaps, and interest rate swaps valued using observable inputs.

- Level 3 - Level 3 inputs are pricing inputs that are generally less observable or unobservable from objective sources. These inputs are used with internally developed methodologies to produce management's best estimate of fair value for the asset or liability. Level 3 consists primarily of financial transmission rights.

The values of financial transmission rights are based on unobservable inputs, including estimates of congestion costs in MISO between applicable generation and load pricing nodes based on the 50th percentile of historical prices. They are classified as Level 3 assets and liabilities. The valuations of these assets and liabilities are performed by the Office of Corporate Risk Oversight. The values are calculated internally and verified against the data published by MISO. Entergy's Accounting group reviews these valuations for reasonableness, with the assistance of others within the organization with knowledge of the various inputs and assumptions used in the valuation. The Office of Corporate Risk Oversight reports to the Vice President and Treasurer. The Accounting group reports to the Chief Accounting Officer.

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' assets and liabilities that are accounted for at fair value on a recurring basis as of December 31, 2025 and December 31, 2024. The assessment of the significance of a particular input to a fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

Entergy Arkansas

2025	Level 1	Level 2	Level 3	Total
			(In Millions)	
Assets:				
Temporary cash investments	\$268.5	\$—	\$—	\$268.5
Decommissioning trust funds (a):				
Equity securities	20.0	—	—	20.0
Debt securities	251.9	362.1	—	614.0
Common trusts (b)				1,182.3
Financial transmission rights	—	—	5.5	5.5
	<u>\$540.4</u>	<u>\$362.1</u>	<u>\$5.5</u>	<u>\$2,090.3</u>
2024	Level 1	Level 2	Level 3	Total
			(In Millions)	
Assets:				
Temporary cash investments	\$3.4	\$—	\$—	\$3.4
Decommissioning trust funds (a):				
Equity securities	12.9	—	—	12.9
Debt securities	259.9	319.1	—	579.0
Common trusts (b)				1,012.5
Financial transmission rights	—	—	8.5	8.5
	<u>\$276.2</u>	<u>\$319.1</u>	<u>\$8.5</u>	<u>\$1,616.3</u>

- a. The decommissioning trust funds hold equity and fixed income securities. Equity securities are invested to approximate the returns of major market indices. Fixed income securities are held in various governmental and corporate securities. See Note 16 to the financial statements for additional information on the investment portfolios.
- b. Common trust funds are not publicly quoted and are valued by the fund administrators using net asset value as a practical expedient. Accordingly, these funds are not assigned a level in the fair value table. The fund administrator of these investments allows daily trading at the net asset value and trades settle at a later date.

The following table sets forth a reconciliation of changes in the net assets (liabilities) for the fair value of financial transmission rights classified as Level 3 in the fair value hierarchy for the year ended December 31, 2025.

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Millions)		
Balance as of January 1, 2025	\$8.5	\$8.6	(\$0.5)	\$1.3	\$1.9
Issuances of financial transmission rights	11.8	28.7	1.5	2.9	4.0
Gains included as a regulatory liability/asset	36.5	80.4	10.9	12.6	12.0
Settlements	(51.3)	(101.0)	(11.5)	(15.0)	(15.8)
Balance as of December 31, 2025	\$5.5	\$16.7	\$0.4	\$1.8	\$2.1

The following table sets forth a reconciliation of changes in the net assets (liabilities) for the fair value of financial transmission rights classified as Level 3 in the fair value hierarchy for the year ended December 31, 2024.

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Millions)		
Balance as of January 1, 2024	\$6.0	\$9.8	\$1.4	\$1.1	\$2.4
Issuances of financial transmission rights	17.6	21.6	3.9	2.8	7.3
Gains included as a regulatory liability/asset	44.7	48.9	1.7	4.3	10.0
Settlements	(59.8)	(71.7)	(7.5)	(6.9)	(17.8)
Balance as of December 31, 2024	\$8.5	\$8.6	(\$0.5)	\$1.3	\$1.9

NOTE 16. DECOMMISSIONING TRUST FUNDS

The NRC requires certain of the Utility operating companies and System Energy to maintain nuclear decommissioning trusts to fund the costs of decommissioning ANO 1 and 2, River Bend, Waterford 3, and Grand Gulf. Entergy's nuclear decommissioning trust funds invest in equity securities, fixed-rate debt securities, and cash and cash equivalents.

Entergy records decommissioning trust funds on the balance sheet at their fair value. Because of the ability of the Registrant Subsidiaries to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, for unrealized gains/(losses) on investment securities, the Registrant Subsidiaries record an offsetting amount in other regulatory liabilities/assets. Generally, Entergy records gains and losses on its debt and equity securities using the specific identification method to determine the cost basis of its securities.

Entergy Arkansas

Entergy Arkansas holds equity securities and available-for-sale debt securities in nuclear decommissioning trust accounts. The available-for-sale debt securities held as of December 31, 2025 and 2024 are summarized as follows:

	2025	2024
		(In Millions)
Fair value	\$614.0	\$579.0
Unrealized gains	\$7.5	\$1.2
Unrealized losses	\$14.2	\$25.8

The amortized cost of available-for-sale debt securities was \$620.7 million as of December 31, 2025 and \$603.5 million as of December 31, 2024. As of December 31, 2025, the available-for-sale debt securities had an average coupon rate of approximately 3.88%, an average duration of approximately 6.49 years, and an average maturity of approximately 8.86 years.

The unrealized gains/(losses) recognized during the year ended December 31, 2025 on equity securities still held as of December 31, 2025 were \$137.5 million. The equity securities are generally held in funds that are designed to approximate or somewhat exceed the return of the Standard & Poor's 500 Index. A relatively small percentage of the equity securities are held in funds that are designed to approximate or somewhat exceed the return of the Wilshire 4500 Index. The debt securities are generally held in individual government and credit issuances.

The fair value and gross unrealized losses of available-for-sale debt securities, summarized by length of time that the securities had been in a continuous loss position, were as follows as of December 31, 2025 and 2024:

	2025		2024	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
			(In Millions)	
Less than 12 months	\$89.1	\$0.6	\$282.8	\$8.2
More than 12 months	211.1	13.6	195.0	17.6
Total	\$300.2	\$14.2	\$477.8	\$25.8

The fair value of available-for-sale debt securities, summarized by contractual maturities, as of December 31, 2025 and 2024 are as follows:

	2025	2024
		(In Millions)
Less than 1 year	\$27.7	\$31.7
1 year - 5 years	140.2	142.5
5 years - 10 years	256.8	231.0
10 years - 15 years	69.1	62.2
15 years - 20 years	61.4	62.8
20 years+	58.8	48.8
Total	\$614.0	\$579.0

The following table summarizes proceeds from the dispositions of available-for-sale debt securities and the related gains and losses from the sales for the years ended December 31, 2025, 2024, and 2023:

	2025	2024	2023
		(In Millions)	
Proceeds from disposition of securities	\$41.7	\$210.6	\$28.5
Realized gains	\$0.5	\$0.1	\$0.1
Realized losses	\$0.1	\$35.8	\$2.0

During the years ended December 31, 2025, 2024, and 2023, gross gains and gross losses related to available-for-sale debt securities were reclassified out of other regulatory liabilities/assets into earnings.

NOTE 17. VARIABLE INTEREST ENTITIES

Note 17 to the financial statements is not applicable to the presentation of the FERC Form 1.

NOTE 18. TRANSACTIONS WITH AFFILIATES

Each Registrant Subsidiary purchases electricity from or sells electricity to the other Registrant Subsidiaries, or both, under rate schedules filed with the FERC. The Registrant Subsidiaries receive management, technical, advisory, operating, and administrative services from Entergy Services; and receive management, technical, and operating services from Entergy Operations. These transactions are on an "at cost" basis.

The tables below contain the various affiliate transactions of the Utility operating companies, System Energy, and other Entergy affiliates.

Intercompany Revenues

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>	<u>System Energy</u>
			(In Millions)			
2025	\$96.0	\$386.5	\$1.0	\$0.4	\$—	\$581.4
2024	\$111.8	\$312.8	\$1.0	\$—	\$—	\$583.3
2023	\$125.2	\$317.6	\$1.0	\$—	\$0.7	\$588.4

Intercompany Operating Expenses

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>	<u>System Energy</u>
			(In Millions)			
2025	\$534.0	\$639.6	\$434.4	\$294.0	\$313.7	\$146.8
2024	\$540.6	\$649.3	\$339.6	\$293.9	\$319.4	\$166.6
2023	\$585.8	\$719.8	\$345.2	\$302.5	\$316.8	\$179.0

Intercompany Interest and Investment Income

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>	<u>System Energy</u>
			(In Millions)			
2025	\$1.7	\$299.1	\$2.9	\$0.3	\$0.7	\$0.5
2024	\$2.2	\$315.4	\$0.4	\$0.2	\$2.7	\$0.8
2023	\$0.7	\$303.2	\$0.2	\$1.0	\$1.8	\$0.6

NOTE 19. SUBSEQUENT EVENT

Management has evaluated the impact of events after December 31, 2025 up to February 19, 2026, the date that Entergy Arkansas's U.S. GAAP financial statements were issued and has updated such evaluations for disclosure purposes through April 3, 2026. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								324,766,014	
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								440,531,995	
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	16,139,902,433	\$16,139,902,433					
4	Property Under Capital Leases	\$112,764,802	112,764,802					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	745,292,559	745,292,559					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	16,997,959,794	16,997,959,794					
9	Leased to Others							
10	Held for Future Use	408,814	408,814					
11	Construction Work in Progress	623,032,579	623,032,579					
12	Acquisition Adjustments	44,516,241	44,516,241					
13	Total Utility Plant (8 thru 12)	17,665,917,428	17,665,917,428					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	6,301,385,359	\$6,301,385,359					
15	Net Utility Plant (13 less 14)	11,364,532,069	11,364,532,069					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	6,268,611,426	\$6,268,611,426					
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	\$4,304,884	4,304,884					
22	Total in Service (18 thru 21)	6,272,916,310	6,272,916,310					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							

28	Depreciation	100,710	100,710					
29	Amortization							
30	Total Held for Future Use (28 & 29)	100,710	100,710					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	28,368,339	28,368,339					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,301,385,359	6,301,385,359					

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases
Includes Operating Leases recorded in accordance with FASB ASU No. 2016-02, Leases, as provided for in FERC Docket No. AI19-1-000.
(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService
Includes a credit balance of \$4,304,884 of accumulated provision for amortization of intangible assets.
(c) Concept: UtilityPlantInServiceClassified
Includes \$287,807,646 related to asset retirement cost assets.
(d) Concept: AccumulatedProvisionForDepreciationAmortizationAndDepletionOfPlantUtility
Includes a credit balance of \$145,273,520 for asset retirement obligation-related accumulated provisions.
(e) Concept: DepreciationUtilityPlantInService
Includes a credit balance of \$145,273,520 for asset retirement obligation-related accumulated provisions.
(f) Concept: AccumulatedProvisionForDepreciationAmortizationAndDepletionOfPlantUtility
Includes a credit balance of \$145,273,520 for asset retirement obligation-related accumulated provisions.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials	82,940,951	64,909,678		\$71,537,673	76,312,956
4	Allowance for Funds Used during Construction	3,262,564	3,624,740		\$3,096,509	3,790,795
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)	86,203,515				80,103,751
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)	\$165,658,030	131,488,864	86,377,801		\$210,769,093
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	(5,671,495)	(8,169,763)	(2,008,262)		(11,832,996)
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	257,533,040				302,705,840
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)					0

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: NuclearFuelUnderCapitalLeases

As of December 31, 2025, arrangements to lease nuclear fuel existed in an aggregate amount up to \$240 million for Entergy Arkansas. The lessors finance the acquisition and ownership of nuclear fuel through loans made under revolving credit agreements, the issuance of commercial paper, and the issuance of intermediate-term notes. The credit agreements for Entergy Arkansas have a termination date of June 25, 2027. The intermediate-term notes issued pursuant to these fuel lease arrangements have varying maturities through May 1, 2029. It is expected that additional financing under the leases will be arranged as needed to acquire additional fuel, to pay interest, and to pay maturing debt. However, if such additional financing cannot be arranged, the lessee in each case must repurchase sufficient nuclear fuel to allow the lessor to meet its obligations in accordance with the fuel lease.

(b) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Withdrawals and allocation adjustments related to the regulated nuclear pool.

(c) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Withdrawals and allocation adjustments related to the regulated nuclear pool.

(d) Concept: NuclearFuelUnderCapitalLeases

FUEL LEASE FOR ARKANSAS NUCLEAR ONE
LESSOR: RIVER FUEL TRUST #1

Investment of River Fuel Trust #1 at December 31, 2025	
Investment at December 31, 2024	\$165,658,030
Additional investment in fuel	129,928,850
Daily lease charges allocated to and included in capitalized costs	1,560,014
Less: Burn-up charges paid to lessor	86,377,801
Total Investment at December 31, 2025	\$210,769,093
Cost Incurred under River Fuel Trust #1 Lease for the Year Ended December 31, 2025	
Daily Lease Charges	\$4,900,277

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- 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.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- 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.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- 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.
- 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.
- 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.
- 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	33,366					33,366
3	(302) Franchise and Consents	3,832,306					3,832,306
4	(303) Miscellaneous Intangible Plant	914,717,986				(911,589,202)	3,128,784
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	918,583,658				(911,589,202)	6,994,456
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	2,128,299		274,535			1,853,764
9	(311) Structures and Improvements	68,287,831	1,645,920	166,907			69,766,844
10	(312) Boiler Plant Equipment	530,629,707	3,090,062	1,157,699			532,562,070
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	153,990,909	470,575	301,614			154,159,870
13	(315) Accessory Electric Equipment	64,585,011	322,391	105,060			64,802,342
13.1	(315.1) Computer Hardware		892	1,547		2,199,014	2,198,359
13.2	(315.2) Computer Software					440,671	440,671
13.3	(315.3) Communication Equipment					1,406,293	1,406,293
14	(316) Misc. Power Plant Equipment	15,664,736	69,052	11,223		(3,292,001)	12,430,564
15	(317) Asset Retirement Costs for Steam Production	47,422,653					47,422,653
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	882,709,146	5,598,892	2,018,585		753,977	887,043,430
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	2,641,307	107,891				2,749,198
19	(321) Structures and Improvements	678,256,978	8,916,128	1,924,006			685,249,100
20	(322) Reactor Plant Equipment	1,818,654,446	27,284,277	10,003,171			1,835,935,552

21	(323) Turbogenerator Units	496,454,767	173,454,348	5,965,203		663,943,912
22	(324) Accessory Electric Equipment	384,559,762	7,221,582	854,013		390,927,331
22.1	(324.1) Computer Hardware		334,947		16,975,587	17,310,534
22.2	(324.2) Computer Software		4,667,384		173,876,720	178,544,104
22.3	(324.3) Communication Equipment		1,128,750	15,890	12,307,056	13,419,916
23	(325) Misc. Power Plant Equipment	417,497,212	2,472,762	1,780,645	(26,154,217)	392,035,112
24	(326) Asset Retirement Costs for Nuclear Production	222,655,016				222,655,016
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	4,020,719,488	225,588,069	20,542,928	177,005,146	4,402,769,775
26	C. Hydraulic Production Plant					
27	(330) Land and Land Rights	1,304,416				1,304,416
28	(331) Structures and Improvements	3,913,604	102,300	81,161		3,934,743
29	(332) Reservoirs, Dams, and Waterways	16,602,378	186	2,045		16,600,519
30	(333) Water Wheels, Turbines, and Generators	23,613,629	603,783	219,143		23,998,269
31	(334) Accessory Electric Equipment	3,749,053	1,725			3,750,778
31.1	(334.1) Computer Hardware				906,848	906,848
31.2	(334.2) Computer Software		266,207			266,207
31.3	(334.3) Communication Equipment		23,601		178,083	201,684
32	(335) Misc. Power Plant Equipment	3,881,135	364,222	53,266	(1,084,931)	3,107,160
33	(336) Roads, Railroads, and Bridges					
34	(337) Asset Retirement Costs for Hydraulic Production	7,341				7,341
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	53,071,556	1,362,024	355,615		54,077,965
35.1	D. Solar Production Plant					
35.2	(338.1) Land and Land Rights		24,476,400		200,199	24,676,599
35.3	(338.2) Structures and Improvements		35,422,608		35,968,982	71,391,590
35.5	(338.4) Solar Panels		454,152,972	347,004	123,927,576	577,733,544
35.6	(338.5) Collector System		60,189,520			60,189,520
35.7	(338.6) Generator Step-up Transformers (GSU)		7,877,651	379,867		7,497,784
35.8	(338.7) Inverters		31,540,907	499,053		31,041,854
35.9	(338.8) Other Accessory Electrical Equipment		21,115,090	1,238,262	29,162,048	49,038,876
35.10	(338.9) Computer Hardware		5,010,037			5,010,037
35.11	(338.10) Computer Software				612,364	612,364
35.12	(338.11) Communication Equipment		75,202			75,202
35.13	(338.12) Miscellaneous Power Plant Equipment		829,764		1,760,775	2,590,539
35.14	(338.13) Asset Retirement Costs for Solar Production				17,722,636	17,722,636
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)		640,690,151	2,464,186	209,354,580	847,580,545
35.16	E. Wind Production Plant					

35.17	(338.20) Land and Land Rights						
35.18	(338.21) Structures and Improvements						
35.20	(338.23) Wind Turbines						
35.21	(338.24) Wind Towers and Fixtures						
35.23	(338.26) Collector System						
35.24	(338.27) Generator Step-up Transformers (GSU)						
35.25	(338.28) Inverters						
35.26	(338.29) Other Accessory Electrical Equipment						
35.27	(338.30) Computer Hardware						
35.28	(338.31) Computer Software						
35.29	(338.32) Communication Equipment						
35.30	(338.33) Miscellaneous Power Plant Equipment						
35.31	(338.34) Asset Retirement Costs for Wind Production						
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)						
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. Other Production Plant						
37	(340) Land and Land Rights	29,672,520	(24,291,579)			(200,199)	5,180,742
38	(341) Structures and Improvements	504,397,189	(54,326,988)	414,121		(35,968,982)	413,687,098
39	(342) Fuel Holders, Products, and Accessories	5,943,688					5,943,688
40	(343) Prime Movers	230,881,799	8,559,345	3,451,949			235,989,195
41	(344) Generators	869,083,392	(403,629,516)	3,976,807		(123,927,576)	337,549,493
42	(345) Accessory Electric Equipment	186,247,120	(121,796,696)	20,420		(29,162,048)	35,267,956
42.1	(345.1) Computer Hardware		674,775			2,749,110	3,423,885
42.2	(345.2) Computer Software		(577,485)			965,000	387,515

42.3	(345.3) Communication Equipment					47,630	47,630
43	(346) Misc. Power Plant Equipment	10,567,044	(1,398,472)	23,978		(4,107,333)	5,037,261
44	(347) Asset Retirement Costs for Other Production	17,722,636				(17,722,636)	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,854,515,388	(596,786,616)	7,887,275		(207,327,034)	1,042,514,463
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	6,811,015,578	276,452,520	33,268,589		179,786,669	7,233,986,178
47	3. Transmission Plant						
48	(350) Land and Land Rights	83,714,305	3,370,391			(1,035,806)	86,048,890
48.2	(351.1) Computer Hardware		364,996			12,483,372	12,848,368
48.3	(351.2) Computer Software		232,431			89,080,717	89,313,148
48.4	(351.3) Communication Equipment		3,361,820	180,814		120,593,138	123,774,144
49	(352) Structures and Improvements	134,200,206	(2,464,360)	202,106		(8,856,788)	122,676,952
50	(353) Station Equipment	1,486,169,621	20,222,020	4,295,924		(196,091,680)	1,306,004,037
51	(354) Towers and Fixtures	146,355,281	285	304,097			146,051,469
52	(355) Poles and Fixtures	631,246,842	23,588,004	4,750,048			650,084,798
53	(356) Overhead Conductors and Devices	511,399,231	9,425,481	1,445,578		(33,220,999)	486,158,135
54	(357) Underground Conduit	18,568					18,568
55	(358) Underground Conductors and Devices	47,820				(6,912)	40,908
56	(359) Roads and Trails	1,899,786					1,899,786
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,995,051,660	58,101,068	11,178,567		(17,054,958)	3,024,919,203
59	4. Distribution Plant						
60	(360) Land and Land Rights	27,067,980	8,587,537			1,035,806	36,691,323
61	(361) Structures and Improvements	81,088,677	49,377,772	64,474		9,038,183	139,440,158
62	(362) Station Equipment	654,651,697	31,108,604	1,971,789		(22,248,991)	661,539,521
63.1	(363.1) Computer Hardware		1,139	59,059		1,163,694	1,105,774
63.2	(363.2) Computer Software		6,147,911			176,296,986	182,444,897
63.3	(363.3) Communication Equipment		2,233,330	35,966		119,047,103	121,244,467
64	(364) Poles, Towers, and Fixtures	1,041,996,268	90,306,551	8,653,228			1,123,649,591
65	(365) Overhead Conductors and Devices	919,236,561	57,285,363	16,463,377		(185,740)	959,872,807
66	(366) Underground Conduit	155,885,267	15,885,319	243,088			171,527,498
67	(367) Underground Conductors and Devices	225,144,058	12,739,991	846,402			237,037,647
68	(368) Line Transformers	1,232,112,196	80,946,220	9,786,954			1,303,271,462
69	(369) Services	344,970,578	2,839,922	557,391			347,253,109
70	(370) Meters	256,498,495	20,685,919	1,611,779			275,572,635
71	(371) Installations on Customer Premises	76,179,867	8,500,776	5,430,060			79,250,583
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	130,003,608	4,441,279	1,025,337			133,419,550

74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,144,835,252	391,087,633	46,748,904		284,147,041	5,773,321,022
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements						
84.4	(387.3) Energy Storage Equipment						
84.6	(387.5) Collector System						
84.7	(387.6) Generator Step-up Transformers (GSU)						
84.8	(387.7) Inverters						
84.9	(387.8) Computer Hardware						
84.10	(387.9) Computer Software						
84.11	(387.10) Communication Equipment						
84.12	(387.11) Miscellaneous Energy Storage Equipment						
84.13	(387.12) Asset Retirement Costs for Energy Storage						
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)						
85	7. General Plant						
86	(389) Land and Land Rights	10,470,350					10,470,350
87	(390) Structures and Improvements	208,107,092	4,622,318	1,191,813			211,537,597
88	(391) Office Furniture and Equipment	24,662,162	877,764	68,340		(20,394,447)	5,077,139
89	(392) Transportation Equipment	93,045	3,411,794				3,504,839
90	(393) Stores Equipment	297,157	122,195	5,486			413,866
91	(394) Tools, Shop and Garage Equipment	19,924,985	2,831,172	589,489			22,166,668
92	(395) Laboratory Equipment	786,311		89,143			697,168
93	(396) Power Operated Equipment	36,268					36,268
94	(397.1) Computer Hardware		5,733,002	5,225,063		17,202,518	17,710,457
94.1	(397.2) Computer Software		32,505,495			470,316,745	502,822,240

94.2	(397.3) Communication Equipment	75,693,198	8,362,560	14,643,536		(2,414,366)	66,997,856
95	(398) Miscellaneous Equipment	2,605,022	2,095,344	160,681			4,539,685
96	SUBTOTAL (Enter Total of lines 86 thru 95)	342,675,590	60,561,644	21,973,551		464,710,450	845,974,133
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	342,675,590	60,561,644	21,973,551		464,710,450	845,974,133
100	TOTAL (Accounts 101 and 106)	16,212,161,738	786,202,865	113,169,611			16,885,194,992
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	16,212,161,738	786,202,865	113,169,611			16,885,194,992

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

[\(a\)](#) Concept: ElectricPlantInServiceAdditions

The negative project additions include reversal credits from prior year additions for unclassified project costs closed to plant in service.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
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42						
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44						
45						
46						
47	TOTAL					

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Land and Land Rights Under \$250,000			264,401
3				
21	Other Property:			
22	Other Property Under \$250,000			144,413
47	TOTAL			408,814

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION LINES PLANT:	
2	EAL LP ARDOT PROJECT 070367 HWY	2,464,955
3	EAL LP ARDOT PROJECT CA0613: UG POR	1,569,393
4	EAL LP; SA24A005_Feeder_L223, Devic	1,370,698
5	EAL LP ARDOT PROJECT 070367 - UG Po	1,357,281
6	EAL LP ARDOT PROJECT CA0613: OH POR	1,267,108
7	2023 FLIP EAL Southeast L221	1,161,628
8	V970 BUILD OUT - ALEXANDER SUB - AL	824,832
9	EAL Severe Weather (9/22-24/2025)	782,362
10	EAL LP; FC24A002_Feeder_C151_Device	534,239
11	EAL LP - Iron Bluffs - Roun	514,356
12	EAL LP ARDOT PROJECT 020475 HWY 83	486,685
13	EAL LP; V930 - LR ALEXANDER - BASS	476,532
14	EAL LP; FOCUS PROJECT FC24A035 -MAG	461,312
15	NORTHSHORE FACILITY BURIAL & RECOND	457,886
16	Blake Hill Sub formerly Black Snake	401,212
17	EAL LP FOCUS 2021: Breaker: C343 De	394,861
18	FC24A033-HOT SPRINGS -Z467...	364,159
19	EAL Severe Weather (11/24-25/2025)	347,442
20	2023 FLIP EAL Southeast L432	341,677
21	EAL Severe Weather (10/18/2025)	336,369
22	2023 FLIP EAL Northeast N481	334,587
23	EAL LP; FC23A035_Feeder_L141_Device	333,069
24	EAL LP; LRAFB Items 6-9	323,541
25	2023 FLIP EAL Northeast P513 - Regu	322,364
26	IMPROVE - Harrisburg T&D Placeholde	321,841
27	EAL LP ARDOT PROJECT 061344: HWY 67	319,182
28	HIGHWAY - Highway Relocation - OH -	319,099
29	EAL LP ARDOT PROJECT 110614: OH POR	318,647
30	4500 RIVER PORT RD-AMAZON LIT3-UG L	309,085

31	EAL LP; FOCUS - FOCUS: FC23A073, Y4	308,311
32	2023 FLIP EAL Central G950 LONG LEA	306,581
33	2023 FLIP EAL Central V380	296,047
34	St. Francis Sub CKT 130	273,191
35	2023 FLIP EAL Central G830	267,892
36	SECTION - SHN G950- G935 - G970	267,496
37	IMPROVE - BLAKEHILL FEEDER 3 - SUB	247,883
38	EAL_T&D Little Rock Enhanced Reliab	243,912
39	2025 - IMPROVE - DARDANELLE - K930	352,558
40	RELIABILITY - 134D	230,167
41	EAL LP; UG FACILITIES TABER EXTRUSI	226,341
42	EAL LP ARDOT PROJECT 090647 : OH PO	220,858
43	NORTHSHORE PARK - D130 - COOKS LAND	220,220
44	EAL LP; FC24A003_Feeder_C456_Device	219,635
45	2023 FLIP EAL Southwest Y406	217,723
46	C3-HIGHWAY - S213 & S217 - Goblin D	216,512
47	FC24A059 - F930 - 1973F	211,715
48	EAL LP CUSTOMR - Downtown Project -	201,082
49	NEW GRAIN	197,456
50	EAL LP ARDOT PROJECT 050420: OH POR	196,761
51	EAL LP ARDOT PROJECT 020675 (PART 1)	193,458
52	EAL LP ARDOT PROJECT 020768 : OH PR	191,277
53	2025 - IMPROVE - ATKINS - G430 - Re	180,336
54	EAL LP ARDOT PROJECT 061382: OH POR	176,236
55	EAL LP; FC24A021_Feeder_C530_Dev	175,310
56	FOCUS-SA24A022-EL DORADO-CIRCUIT A2	167,529
57	EAL LP FOCUS - MARION W205 1R30 FC2	165,730
58	Improve - Joint T&D Harrisburg 161k	164,036
59	EAL Severe Weath/Wind (12/28-29/25)	160,578
60	EAL LP; RELIAB - Target Device Reli	159,879
61	EAL LP; PORT SUB V835-FRAZIER PIKE-	156,045
62	Minor Add 061331 Phase I	156,030
63	HIGHWAY -2023- A127-BKR A127- Hwy16	153,716
64	EAL LP; - FOCUS-FC24A038-HOT SPRING	151,057
65	IMPROVE - CW25-013V - Hamlet - N610	143,536
66	EAL LP; FRAZIER PIKE-V835 SAGE V-UG	142,304
67	EAL LP; FOCUS_SA24A013_Feeder: L391	138,767

68	EAL LP ARDOT PROJECT 090578: OH POR	138,723
69	EAL LP; WHITE OAK-CYPRESS BEND PH I	132,295
70	EAL LP; PORT SUB V835-NORTH UG EXT	129,621
71	EAL LP ARDOT PROJECT 020717 HWY 270	129,572
72	EAL LP ARDOT PROJECT 020770 : OH PO	128,501
73	Regulator replacement CEQ 1434690	116,940
74	EAL LP ARDOT PROJECT 061737	115,899
75	CUST IMP OH/UG RELIAB - 1G41 Latera	108,045
76	FOCUS-SA24A023-ELDORADO-CIRCUIT A13	107,669
77	EAL LP; FC24A014_C182_3C02_Ulm, Stu	107,588
78	EAL LP; RECONDUCTING DOWN	105,193
79	EAL LP; 1211A 4KV CONVERS	104,532
80	EAL LP; 6101 ZEUBER RD-ELOPAK-UG BO	103,276
81	FOCUS-FC25A017-F310 - CI 534	102,243
82	EAL LP; FRAZIER PIKE SUB-WEST FEED	102,016
83	PSV009- Hot Springs Blake Hill- Fee	100,084
84	Other distribution lines plant	1,819,385
85	GENERAL AND INTANGIBLE PLANT:	
86	FSM Click Replacement SW	3,605,613
87	Helicopter acquisition EAL	3,569,278
88	GMS Software Upgrade	2,745,043
89	Update T&D Maximo to IBM MAS 9.1	2,324,283
90	Distribution Resiliency Plan	1,781,721
91	Prior leased equipment purchases	2,891,161
92	Tools and equipment purchases	1,393,421
93	Nuclear PDS Replacement	894,787
94	LFN - Environmental Health Safety S	853,258
95	Accr Prx Code-Dist Cap EAL	833,505
96	PD Capital Prioritization ESI	762,685
97	Power Compass	679,027
98	Accr Prx Code-TRN AM Cap EAL	611,450
99	2024 Documentum Upgrade & OpenPass	582,882
100	Endevor Work Planning Digitization	487,750
101	Adv. Facilities Rating Mgmt - Ph 2	342,305
102	Continuous Improvement - Accrual Capital Proxy Code	290,009
103	Accr Prx Code-TRN Storm Cap Ark	240,683
104	View Outage Map	223,486

105	SharePoint Online Upgrade	149,016
106	Nuclear Cyber Kiosks/Laptops ANC	139,274
107	EAL Aviation Drone Fleet	138,065
108	IT Systems: PwrThr Asset Management	136,002
109	BRIGHT - Release 3	126,526
110	Accr Prx Code-Dist Storm Cap EAL	116,134
111	API Security	107,039
112	AiDash CRIS Wildfire	103,468
113	EAL Fleet Rotary Lifts	101,918
114	Other general and intangible plant	957,821
115	PRODUCTION PLANT:	
116	EAL Lake Catherine Unit 5	137,372,916
117	ANO2 RVCH and CEDM Replacement	64,838,169
118	EAL Jefferson Power Station	56,944,460
119	HT1 - Hot Spring LTSA Capital	23,337,753
120	Arkansas Cypress Solar North	18,212,204
121	ANO2 RVLMS Obsolete Equip	16,017,324
122	UP2 LTSA Adjustments Capital	15,893,787
123	ANO2 ECP Supply Piping Replacement	15,799,886
124	ANO1 ECP Supply Piping Replacement	13,962,363
125	AN1 RCS HOT LEG ALLOY 600 RCS MOD	8,126,421
126	WB1 - New 910 MVA Transformer	8,073,062
127	ANO1 Process Computer Upgrade	8,012,006
128	AN2 2VCH-1A 1B Main Chiller Repl	7,780,118
129	ANC Security Defensive Strategy Upg	7,281,449
130	OP1 LTSA Services Capital	7,181,184
131	OP2 LTSA Services Capital	7,087,482
132	UP2 - Cooling Tower Repl - FRP Conv	6,210,404
133	UP2A - Advance Gas Path (AGP Tech)	5,997,661
134	AN2 Repl 2E-6A/2E-7A FW Tube Bundle	4,648,052
135	EAL Black Branch Unit 1	4,129,337
136	AN1 SUBSEQUENT LICENSE RENEWAL	3,569,350
137	OP1 - AdvanceGas Path (AGPTech)RPLC	3,404,617
138	AN2 THERMAL SLEEVE REMOVAL TOOL	3,270,046
139	UP2B - Advance Gas Path (AGP Tech)	3,069,235
140	HT1A-Advance Gas Path (AGP Tech) Up	3,068,406
141	HT1B-Advance Gas Path (AGP Tech) Up	3,068,406

142	ANO1 ICW Heat Exchanger A & B Repl	3,050,408
143	AN1 Replace CRD CEDM Power Cables	2,599,426
144	EAL WB Purchase	2,492,222
145	UP2 - 2C HP/IP Diaphragm Exchange	2,268,064
146	AN2 Obsolete CPC System Replacement	2,026,441
147	AN1 RV Flange Leak Offline Repl.	2,005,016
148	ANC REPL SEISMC MONITORING SYSTEM	1,919,942
149	U2 Repl MFW Turbine Rotor 2K-2A	1,677,700
150	Conditioned Based Transmitters ANO	1,595,710
151	AN2 2Y-26 Inverter Replacement	1,573,734
152	AN2 Refurb/Repl 2CV-1010-1/1060-2	1,493,099
153	ANO2 "B" EDG Exciter/Voltage Regula	1,459,309
154	RDC Spillway Gate Hoist Remote Oper	1,450,695
155	AN1 PROCURE SPARE MAIN TRANSFORMER	1,364,796
156	SW PIPING REPLX 2VCC-2A/B	1,348,740
157	AN2 Refurb Circ Water Pump 2P-3A/B	1,314,428
158	AN2 ECP SW RETURN EXPOXY COATING	1,271,471
159	AN2 Repl SW Pipe 2E-35B Heat XChang	1,141,977
160	AN2 REPL LOSS OF FIELD RELAY	1,081,189
161	EAL Driver Solar O&M Building	1,026,793
162	EAL - White Bluff Gas Conv Unit 1	959,820
163	AN2 Repl 2VUC-30 SPDS Room Cooler	948,980
164	ANC Ground Water Mitigation	922,200
165	SPO Big Island Solar BOT Transactio	910,883
166	EAL EI Dorado CCCT	860,636
167	AN2 SUBSEQUENT LICENSE RENEWAL	849,231
168	2R30 REPL MAGNESIUM ROTOR MOTOR	826,936
169	ANO1 1R31 SW Supply Header Loop	809,644
170	ANO2 2R31 SW Supply Header Loop	772,757
171	ANC Scoping Study for Fire Sys Repl	737,583
172	AN1 SW Piping Replacement 1R34	718,733
173	SPO EAL West Memphis Spare Parts	706,013
174	EAL-Arkansas Heart Hospital	652,671
175	ANC REROOF CSB BUILDING	584,228
176	AN1 CW Internal Pipe Re-Coat	557,486
177	HT1 Gas Turbine Inlet Chiller Refur	542,892
178	ANO2 Process Computer Upgrade	528,842

179	AN2 2P-4A SW MOTOR Rewind	507,514
180	AN1 ICC-MDS Replacement	465,288
181	AN2 2M-30 Cooling Tower Fill Repl	445,855
182	AN2 Yokogawa Long Range Plan	442,730
183	AN1 Phse 2 Reactor Bldg Steel Proj.	417,591
184	2R31 12 Year Breaker Refurbishment	407,003
185	AN2 Install Reactor Drain Tank Rack	394,795
186	AN2FWCS -- Long Range Plan for Upgr	379,851
187	AN2 REPL 2CV-0761 VALVE	342,339
188	AN1 Repl RBHV SW Cling Coils VCC-2B	340,130
189	REPLACE 2VCC-2D COOLING COILS	336,215
190	AN2 Target Rock Valve Replacement	303,194
191	CDC - N. Abutment Post Tension Anch	263,288
192	AN2 Refurb 2P-60A LPSI Motor	259,654
193	ANO1 Fire Sys Piping Repl	256,590
194	2R31 ANO 2 Snubber Repl	243,872
195	HT1A - Mark VIe Turbine Controls	235,503
196	HT1B - Mark VIe Turbine Controls	235,503
197	AN2 ADD MAIN STEAM VIB REDUCTION S	229,685
198	AN2HBC-78 SW Pipe Replacement	184,096
199	AN2 REPL 2T-24 COOL TOWER ACID TANK	157,863
200	AN1 EDG GENERATOR INSTALL PERM HEAT	146,529
201	AN1 Repl Butterfly Valve CV-3820	143,197
202	ANOC Spent Fuel Cooling System Mod	127,431
203	AN2 Repl Cooling Tower Bypass Pipe	126,983
204	ANO2 Spent Fuel Handling Equipment	122,808
205	Repl 2SI-16 B/D SIT Outlet Val	119,621
206	Repl Target Rock Valve 2SV-5025A/B	118,853
207	ANO1 Main Refuel Bridge Replacement	118,092
208	U2 Repl Target Rock Valves	110,190
209	AN2 REPL CONTROL ROOM LIGHTING	108,525
210	Other production plant	1,134,339
211	TRANSMISSION AND DISTRIBUTION SUBSTATION:	
212	EI Dorado 500kV Substation	11,530,315
213	Wild Cat 230/500kV Substation	4,885,257
214	Blakehill 115kV: New Sub	4,601,079
215	EI Dorado Chem Co 25.76 MW Add	2,820,825

216	Blakehill Land Purchase	1,009,190
217	Frazier Pike Phase 2 115Kv Install	1,006,362
218	PB Whitehall; HV switches, CS, LV B	908,610
219	GARLAND; BREAKERS AND RELAYS	895,225
220	Magnolia DOW Xfmr Replacement	713,596
221	T20-1 MOBILE EQUIPMENT FAILURE	692,081
222	Dalark Failed Transformer	632,741
223	EAL: Spare 115kV 50MVA (Frazier)	614,797
224	Russellville South; diff panel, LV	576,510
225	AR Grid; purchase tools	551,570
226	EAL: 13.8kV 3.33MVA Reg (Haskell)	500,521
227	Gum Springs: Bld 115kV SS	485,601
228	EI Dorado Upland; replace circuit s	461,561
229	EI Dorado East; replace HV breakers	360,872
230	CIP-014:EAI Phys Sec IT Failures	356,309
231	UPP; failed switch 2C2	331,929
232	McNeil EHV; failed BU carrier relay	322,015
233	EAL: Camlin XFMR Monitor @ HS EHV	285,691
234	LR KANIS RD; VOLTAGE REGULATOR R1	283,610
235	OSCEOLA; FAILED OCB R230 & DISCONN	236,713
236	EAL: Camlin Mon Mayflower AT1/2	233,056
237	Baptist Health Solar Upgd Ulm 115	225,831
238	Replace failed McNeil Primary and B	221,810
239	Sierra 115kV: New Sub	212,924
240	Thibault Rd 115kV Substation	147,300
241	Sherwood 115kV Network Upgrade	137,025
242	Keo 500kV Reconfigure - Add Breaker	136,533
243	SHERWOOD; SWITCH B0628	127,050
244	LR Gaines; failed carrier sets (2)	123,561
245	REPARE SYSTEM SPARE REGULATOR W/LTC	114,689
246	HILO	113,834
247	Other transmission and distribution substation	2,092,945
248	TRANSMISSION LINES PLANT:	
249	Norfolk-Southland 161kV Ln Upgrd	4,885,852
250	3/14 Storms ISES-Searcy Price	1,999,919
251	3/14 Storm ISES-Newport #1	1,523,486
252	C6ML100285 -HAYTI SOUTH-PORTAGEVILL	1,159,566

253	El Dorado-Smalling 500kV T Line	480,396
254	Rebuild Southland to Mntnhome 161kV	468,585
255	C6ML100256-HILO-AECC SUMMERVILLE (8	307,663
256	Donan-Mosanto T-Line 115kV Rebuild	296,646
257	C6ML100425 Failure AECC BOTKINBURG-	157,567
258	Blakehill 115kV Cut-in:Carpenter	145,783
259	115kv AECC Wilmar to Monticello S	111,197
260	EAL: Heimdall - Con W - Morrilton E	101,179
261	Other transmission lines plant	844,563
262	OTHER UNDISTRIBUTED OVERHEADS	1,614,960
43	Total	623,032,579

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	5,384,874,493	5,384,773,783	100,710	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	443,817,760	443,817,760		
4	(403.1) Depreciation Expense for Asset Retirement Costs	12,105,089	12,105,089		
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):	22,186	22,186		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	455,945,035	455,945,035		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(113,169,611)	(113,169,611)		
13	Cost of Removal	(79,384,905)	(79,384,905)		
14	Salvage (Credit)	7,763,837	7,763,837		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(184,790,679)	(184,790,679)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	612,683,287	612,683,287		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,268,712,136	6,268,611,426	100,710	
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	648,218,130	648,218,130		
21	Nuclear Production	2,124,842,415	2,124,842,415		
22	Hydraulic Production-Conventional	22,169,369	22,157,978	11,391	
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production	23,607,240	23,607,240		
23.2	Wind Production				

23.3	Other Renewable Production				
24	Other Production	700,265,674	700,265,674		
25	Transmission	763,076,016	763,076,016		
26	Distribution	1,506,573,696	1,506,573,696		
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	479,959,596	479,870,277	89,319	
29	TOTAL (Enter Total of lines 20 thru 28)	6,268,712,136	6,268,611,426	100,710	

FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAdjustments

Excludes service company depreciation allocations of \$8,544,505 and expense reclassifications of (\$952,598) since these allocations and reclassifications do not offset to accumulated reserves. (they are included in the depreciation expense shown on page 336)

(b) Concept: OtherAccounts

Includes depreciation on railcars, which is accounted for as fuel expense.

(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

Gain on sale of land	\$611,088
FERC Order 898 Transfers (see below - pg 219 excludes Intangible Plant)	(613,294,375)
Total	<u>(612,683,287)</u>

Entergy Arkansas implemented FERC Order 898, effective January 1, 2025, transferring plant balances and the associated accumulated depreciation. Below are the transfers by function:

FERC 898 Implementation

	Plant Transfer	Reserve Transfer	Net Book Value
Intangible Plant	(\$911,589,202)	\$613,294,375	(\$298,294,827)
Steam Production Plant	753,977	(556,820)	197,157
Nuclear Production Plant	176,384,389	(105,039,517)	71,344,872
Solar Production Plant	847,948,378	(2,481,868)	845,466,510
Other Production	(826,161,773)	1,657,919	(824,503,854)
Transmission	(36,814,017)	(72,176,063)	(108,990,080)
Distribution	284,147,041	(88,811,857)	195,335,184
General	465,331,207	(345,886,169)	119,445,038
Total	<u>\$—</u>	<u>\$—</u>	<u>\$—</u>

(d) Concept: AccumulatedDepreciationSteamProduction

Includes a credit balance of \$5,835,830 for asset retirement obligations.

(e) Concept: AccumulatedDepreciationNuclearProduction

Includes a credit balance of \$137,975,634 for asset retirement obligations.

(f) Concept: AccumulatedDepreciationHydraulicProductionConventional

Includes a debit balance of \$45,370 for asset retirement obligations.

(g) Concept: AccumulatedDepreciationSolarProduction

Includes a credit balance of \$1,507,426 for asset retirement obligations.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- 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.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- 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.
- 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.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- 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).
- 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	AR Searcy Partnership, LLC - Subsidiary Company Subheading	06/30/2021						
2	AR Searcy Partnership, LLC - Paid-In-Capital			(7,123,294)		(2,965,873)	(10,089,167)	
3	AR Searcy Partnership, LLC - Capital Contribution			88,750,034			88,750,034	
4	AR Searcy Partnership, LLC - Outside Basis			4,159,300			4,159,300	
5	AR Searcy Partnership, LLC - Unappropriated Undistributed Subsidiary Earnings			(1,445,296)	(208,620)		(1,653,916)	
6	AR Searcy Partnership, LLC - Subtotal			84,340,744	(208,620)	(2,965,873)	81,166,251	
7	Arkansas Power & Light Company - Subsidiary Company Subheading							
8	Arkansas Power & Light Company - Capital Contribution			10,006			10,006	
9	Arkansas Power & Light Company - Unappropriated Undistributed Subsidiary Earnings			204	247		451	
10	Arkansas Power & Light Company - Subtotal			10,210	247		10,457	
42	Total Cost of Account 123.1 \$		Total	84,350,954	(208,373)	(2,965,873)	81,176,708	

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)	34,264,667	26,483,949	
2	Fuel Stock Expenses Undistributed (Account 152)	15,671,999	12,898,284	
3	Residuals and Extracted Products (Account 153)		0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	248,995,407	286,413,306	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	98,819,536	107,388,323	Electric
8	Transmission Plant (Estimated)	1,138,330	1,107,545	Electric
9	Distribution Plant (Estimated)	1,472,861	4,825,368	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	350,426,134	399,734,542	
13	Merchandise (Account 155)		0	
14	Other Materials and Supplies (Account 156)		0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)		0	
16	Stores Expense Undistributed (Account 163)	33,811,939	30,927,347	
17				
18				
19				
20	TOTAL Materials and Supplies	434,174,739	470,044,122	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

		Balance at Beg of Year	
Production (estimated)			\$141,359,403
Transmission (estimated)			31,177,832
Distribution (estimated)			76,458,172
Total Assigned to Construction (estimated)			<u>\$248,995,407</u>

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

		Balance at End of Year	
Production (estimated)			\$140,463,085
Transmission (estimated)			41,623,735
Distribution (estimated)			104,326,486
Total Assigned to Construction (estimated)			<u>\$286,413,306</u>

24													
25													
26													
27													
28	Total	7,702										7,702	
29	Balance-End of Year	322,809	7	35,220		35,220	35,220	919,796	1,348,265	7			
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by authoritative agency												
38	Deduct: Returned by authoritative agency												
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												

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: AllowanceInventoryNumber
Represents allowances in FERC Account 558.1
(b) Concept: AllowancesIssuedLessWithheldAllowancesNumber
Future years include allowances issued from 2029 through 2056.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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					0

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Retired plant - electric meters - APSC Docket No. 16-060-U Order 168 - Amort period 4/2019 - 3/2034 - Commission auth AC19-167-000 September 6, 2019	32,764,506		407	3,542,108	29,222,398
49	TOTAL	32,764,506			3,542,108	29,222,398

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20	Total				
21	Generation Studies				
22					
23					
24					
25					
26					
27					

28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	Total				
40	Grand Total				

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Storm Restoration Costs - APSC Docket No. 15-015-U	29,828,038		571,593	535,582	29,292,456
2	Grand Gulf 1 Cost Rider Under-Recovery	4,525,161	1,891,471			6,416,632
3	MISO Rider Under-Recovery	9,122,066		407.3	962,700	8,159,366
4	Deferred Fuel Under-Recovery		27,769,662			27,769,662
5	Federal Litigation Consulting Fees - APSC Docket No. 07-138-TF	1,878,889		928	1,796,213	82,676
6	Asset Retirement Obligation - Coal	9,204,033	5,019,354			14,223,387
7	Asset Retirement Obligation - Nuclear	677,123,414	50,022,449	407.3	408,283	726,737,580
8	Asset Retirement Obligation - Fossil	5,164,123	1,075,179			6,239,302
9	Asset Retirement Obligation - Hydro	97,066	6,667			103,733
10	Defined Benefit Pension and Other Postretirement Plans	426,355,103		107,926,190,283, 410.1,411.1,253	54,161,365	372,193,738
11	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 130 months effective Oct 2020	5,779,323		926	877,872	4,901,451
12	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 120 months effective July 2021	20,640,540		926	3,175,468	17,465,072
13	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 128 months effective July 2022	19,349,387		926	2,369,312	16,980,075
14	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 139 months effective April 2023	7,855,134		926	798,827	7,056,307
15	TCA/Ice Storm Settlement - APSC Docket No. 01-296-U and APSC Docket No. 01-084-U, Amort 30 years eff Jan 2002	3,686,616		407.3	526,656	3,159,960
16	MOARK Agreement - APSC Docket No. 13-028-U Order No. 21. Amort period 20 year eff Jan 2014	3,899,594		566	433,288	3,466,306
17	Lake Catherine 4 Reliability & Sustainability Costs - APSC Docket No. 15-015-U - Amortization 9.25 years beg March 2016	772,330		403,500,506,507,510, 512,513,514	772,330	
18	ANO Flood Barrier Costs - APSC Docket No. 15-015-U Order No. 18, Amort 10 years thru Feb 2026	1,160,271		517,520,524,525,528, 530,532	994,519	165,752
19	ANO Fukushima Costs - APSC Docket No. 15-015-U Order No. 18, Amort 10 years thru Feb 2026	893,073		403,517,520,524,525, 528,530,531,532,920, 923	765,491	127,582
20	Deferred COVID-19 bad debt expense - APSC Docket No. 20-012-A - Amort Jan 2024-Dec 2033	35,114,431		904	3,901,603	31,212,828
21	Income Taxes	90,720,939	3,437,513	190,282,283,410.1, 411.1	5,762,544	88,395,908

22	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 138 months effective Oct 2022	7,005,330		926	757,333	6,247,997
23	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 135 months effective April 2023	14,033,032		926	1,477,161	12,555,871
24	2026 Rate Case Expense Deferral - APSC Docket No. 26-001-U		383,559			383,559
25	Formula Rate Plan Historical Adjustment - APSC Docket No. 16-036-FR - Amort pd 12 months effective January 2025	15,500,000		407.3	15,500,000	
26	Power Through Generation Development Costs	2,350,013		186	2,350,013	
27	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 276 months effective July 2024	1,101,856		926	48,971	1,052,885
28	Asset Retirement Obligation - Solar	1,414,038	1,797,474			3,211,512
29	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 132 months effective August 2025		1,076,250	926	40,767	1,035,483
30	Qualified Pension Settlement Cost Deferral - APSC Docket No. 20-028-U - Amortization 121 months effective August 2025		848,434	926	35,059	813,375
31	Formula Rate Plan Historical Adjustment - APSC Docket No. 16-036-FR - Amort pd 12 months effective January 2026		28,272,930			28,272,930
44	TOTAL	1,394,573,800	121,600,942		98,451,357	1,417,723,385

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MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Non-Expense Accrued Labor	5,315,325	753,682			6,069,007
2	Other Post Employment Benefits	145,883,000	11,487,999			157,370,999
3	Agric Irrig AMI Load Control - Docket 08-072-TF	1,621,855		930.2	685,969	935,886
4	Pooled Equipment - PEICo	942,569		517	83,221	859,348
5	Other	492,962		131, 228.1	411,127	81,835
6	Production Tax Credits affiliate indemnification costs		15,093,338			15,093,338
7	Production Tax Credits transaction costs		21,998,803			21,998,803
8	Power Through Generation Development Costs - APSC Docket No. 20-049-U		2,927,499			2,927,499
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	154,255,711				205,336,715

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	Intrst/Tax Tax Deficiencies	21,226	21,226
3	ANO Shutdown Costs	(115,426)	(69,425)
4	Grand Gulf 1 - Over/Under Recovery	(1,104,003)	(1,565,466)
5	Taxable Unbilled Revenue	3,546,249	5,490,264
6	Property Insurance Reserve	9,948,195	11,975,053
7	Capitalized Repairs	2,386	1,139
8	Injuries & Damages Reserve	1,261,484	1,575,697
9	Pension Plan	(102,278,116)	(103,252,855)
10	Defined Benefit Pension	92,153,359	78,311,417
11	Supplemental Pension Plan	390,921	406,055
12	Other Post Employment Benefits	(31,615,010)	(33,647,892)
13	Deferred Fuel		(6,774,965)
14	Removal Cost	(56,135,016)	(67,468,814)
15	Acquisition	(1,163,011)	(1,070,834)
16	Solar & Nuclear PTCs Monetized		11,521,237
17	Accrual of Reserves		742,009
18	Asset retirement obligation	188,733	(219,676)
19	Litigation Settlement	844,420	844,420
20	Accrued Medical Claims	1,691,806	1,902,627
21	Uncollectible Accounts	1,139,817	1,781,612
22	Def Gain/Basis Step-Up	236,008	212,411
23	Basis Step-Up	211,092,991	190,840,123
24	Partnership Income/Loss	(42,083)	(54,685)
25	Contract Deferred Revenue	809,423	439,137
26	Environmental Reserve	171,755	171,755
27	Incentive Compensation	4,343,585	3,819,002
28	Long-Term Incentive Compensation	135,114	152,008
29	Stock Options	78,495	103,341
30	Restricted Stock Awards	239,563	309,512

31	Deferred Directors' Fees	54,623	34,055
32	Rate Refund	1,995,020	
33	Reorganization Costs	18,298,674	21,468,075
34	Income tax adjustment	130,365,736	131,948,699
35	Tax Attribute - NOL/CR Carryforward	10,287,766	10,287,766
36	NOL Protected Excess	7,920,801	7,435,876
37	ADIT-NOL-SRLY Fed NonCur	55,703,760	55,703,760
38	ADIT-Contrib Carryforward	996,030	1,502,029
39	ADIT-Tax CR Carryforward	12,889,089	16,113,443
40	Fed Offset-St Carryover	(5,430,332)	(5,694,833)
41	ADIT NOL Carryforward - Fed	65,246,160	112,906,710
42	ADIT NOL Carryforward - St	25,858,726	27,103,862
43	ADIT-Ben-Potnt Disall UTPs Res	5,400,000	5,400,000
44	Tax Credit Valuation Allowance - Fed	(265,603)	(1,727,371)
45	Tax Credit Carryforward PTC - Fed	5,312,067	138,946,300
46	FIN 48 Adjustment		(104,398,896)
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	470,475,382	513,524,908
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	470,475,382	513,524,908
Notes			

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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										
3										
4										
5	Total					0				
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total					0				

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-03	Year/Period of Report End of: 2025/ Q4
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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.

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

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	1,928,477,357
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
15.2	Capital contributions from parent	
16	Ending Balance Amount	1,928,477,357
17	Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,928,477,357

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	0

22													
23	Subtotal											0	
24	Advances from Associated Companies (Account 223)												
25													
26													
27													
28	Subtotal											0	
29	Other Long Term Debt (Account 224)												
30	Solid Waste Disposal - Department of Energy (Nuclear Fuel Disposal Cost)	224										225,308,803	9,292,845
31	Long-Term Obligations - Little Rock Air Force Base distribution facilities 4.2%	224										1,887,804	79,796
32	Subtotal											227,196,607	9,372,641
33	TOTAL		5,060,000,000	39,301,195								5,287,196,607	224,292,224

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FOOTNOTE DATA			

(a) Concept: InterestExpenseOnLongTermDebtIssued
Total interest for Accounts 221 and 224 is recorded in Account 427, as shown on page 117, line 62.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, 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)	440,531,995
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Avoided Cost - Tax Interest	4,887,148
6	Deferred Contract Revenue	(1,517,751)
7	Disallowed Compensation	14,286,293
8	Other Misc Taxable Items	526,656
9	Unbilled Revenue	7,968,251
9	Deductions Recorded on Books Not Deducted for Return	
10	Accrual of Reserves	11,530,456
11	Deferred Compensation and Benefits	2,128,234
12	Dry Cask Amortization	2,008,237
13	Asset Retirement Obligation	(1,674,014)
14	Meals and Entertainment	418,694
15	Nuclear Fuel Burn	86,377,801
16	Penalties	249,056
17	Political Expenses	1,403,500
18	Rate Refund	(8,177,318)
19	Reserve for Uncollectible Accounts	2,630,631
20	Securitization	(939,104)
21	Other	1,711,797
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	27,965,274
16	Equity Earnings in Subs	(208,373)
17	Tax Equity Partnership	51,105
19	Deductions on Return Not Charged Against Book Income	
20	Amortization of Other Assets	6,209,795

21	Amortization of Regulatory Assets	(4,334,892)
22	Bond Reacquisition Loss	(1,232,285)
23	Daily Lease Charges	(966,150)
24	Decommissioning Costs	4,558,310
25	Deferred Compensation & Benefits	750,945
26	Deferred Fuel	27,769,662
27	Depletion	3,080
28	Depreciation of Nuclear Fuel	78,002,202
29	Depreciation of Plant Assets	564,402,230
30	Dividends Received Deduction	7,839,864
31	Service Company Billings	(981,157)
32	Grand Gulf 1 Costs	1,891,471
33	Outage Costs	(12,350,210)
34	Pension and OPEB	10,951,439
35	Prepaid Expenses	407,112
36	Research and Development Costs	109,829,643
37	Software Costs	36,152,892
38	UOP Repairs	235,893,985
39	IRC Sec 475 Mark to Market Adjustments	(4,686,066)
40	Other Deferred Costs	38,990
41	Solar & Nuclear PTCs Monetized	(21,434,796)
42	Other Reconciling Items:	
43	Net Operating Loss	394,155,461
44	Federal Income Tax Accrual - Current year	(27,915)
45	Federal Income Tax Accrual - Prior year	(236,668,910)
46	Investment Tax Credit	(1,230,547)
47	FIN 48 taxes	221,919,207
48	Provision for Deferred Income Tax	128,482,192
49	State Income Tax - Current Year	5,973
50	State Income Tax Accrual - Prior Year	(4,594,882)
27	Federal Tax Net Income	(132,929)
28	Show Computation of Tax:	
29	Normal and Surtax @ 21%	(27,915)
30	Estimated Consolidated Income Tax Allocated	0

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: ComputationOfTax

The Respondent intends to join in the filing of a consolidated Federal Income Tax Return by Entergy Corporation and Subsidiary Companies for the year ended 2025. The estimated consolidated tax allocable under Entergy and Subsidiary Companies Intercompany Income Tax Allocation Agreement based on the provisions of Securities and Exchange Commission Rule 45(c) follows:

Entergy Utility Property, Inc.	(\$38,000)
Entergy Utility Affiliates, LLC	(12,000)
Entergy Utility Assets Holdings, Inc.	2,486,000
Entergy Utility Enterprises, Inc.	1,000
System Energy Resources, Inc.	(5,342,000)
Entergy Operations, Inc.	(109,000)
Entergy Corporation	(112,859,000)
Entergy Nuclear New York Investment Company, LLC	2,000
Entergy Nuclear Holding Company #3, LLC	(3,765,000)
Entergy Assets Management Company, LLC	(3,438,000)
Entergy Northeast Holdings, LLC	(4,411,000)
Entergy Power Marketing Holding II, Inc.	(94,000)
Entergy Nuclear Power Marketing, LLC	1,912,000
Entergy Nuclear, Inc.	(296,000)
Entergy Nuclear Holding Company #1	(4,516,000)
Entergy Nuclear Operations, Inc.	(11,591,000)
Entergy Power Holdings, Inc.	8,877,000
Entergy TransCo HoldCo, LLC	(6,000)
EAM Nelson Holding, LLC	141,000
Entergy Power Investment Holding, Inc.	9,893,000
Entergy Mississippi Turbine Company	(358,000)
Entergy Power, LLC	(213,000)
Entergy Enterprises, Inc.	120,000
Entergy Power Gas Operations, LLC	26,555,000
Entergy Power Marketing Holding I, Inc.	(10,743,000)
Entergy Nuclear Palisades, LLC	(8,878,000)
Entergy Utility Affiliates Holdings, Inc.	1,000
EWO Marketing, LLC	(1,852,000)
Entergy Global, LLC	2,498,000
Entergy Ventures, Inc.	(141,000)
EUP Holdings, LLC	388,000
Entergy Assets Management Holding, Inc.	(15,000)
Entergy Technology Company	(41,000)
Entergy TransCo Texas, LLC	(10,000)
Entergy Services Holding, Inc.	(6,527,000)
Entergy Asset Management, Inc.	6,215,000
Entergy Nuclear Indian Point 2, LLC	(11,916,000)
Entergy Nuclear Indian Point 3, LLC	(11,277,000)
Entergy Finance Company, LLC	156,851,000
Entergy New Orleans, LLC	15,316,000
Entergy Utility Holding Company, LLC	(32,808,000)
Total	\$—

Supplemental Information -Entergy Utility Holding Company, LLC	
Entergy Louisiana, LLC	(\$107,038,000)
Entergy Arkansas, LLC	(28,056,000)
Entergy Mississippi, LLC	46,193,000
Entergy Utility Holding Company, LLC	56,093,000
Total	<u><u>(\$32,808,000)</u></u>
Supplemental Information -Entergy Services Holdings, Inc	
Entergy Services Holdings, Inc.	(\$3,247,000)
Entergy Services, LLC	(2,110,000)
Entergy Account Services, LLC	(1,170,000)
Total	<u><u>(\$6,527,000)</u></u>

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Federal Income Tax	Federal Tax			53,013,265	0	(19,245,613)	(241,199,186)		274,966,838		(28,268,538)			9,022,925
2	FICA	Federal Tax			1,719,746	0	14,176,326	13,947,008		1,949,064		4,729,344			9,446,982
3	Federal Unemployment	Federal Tax			1,057	0	64,836	60,201		5,692		21,586			43,250
4		Federal Tax			0	0						142,039			(142,039)
5	Subtotal Federal Tax				54,734,068	0	(5,004,451)	(227,191,977)	0	276,921,594	0	(23,375,569)	0	0	18,371,118
6	State Income Tax	State Tax			4,218,186	0	(4,750,821)	(3,711,813)		3,179,178		(16,486,725)			11,735,904
7					0	0				0					0
8	Subtotal State Tax				4,218,186	0	(4,750,821)	(3,711,813)	0	3,179,178	0	(16,486,725)	0	0	11,735,904
9	Regulatory Commission	Local Tax			0	2,179,105	4,011,679	3,938,551		0	2,105,977	4,011,679			0
10	Subtotal Local Tax				0	2,179,105	4,011,679	3,938,551	0	0	2,105,977	4,011,679	0	0	0
11	Railcar	Other Taxes			25,230	0	46,793	52,573		19,450					46,793
12	Gross Receipts Privilege Tax	Other Taxes			0	0				0		159			(159)
13	Subtotal Other Tax				25,230	0	46,793	52,573	0	19,450	0	159	0	0	46,634
14	Subtotal Property Tax				0	0	0	0	0	0	0	0	0	0	0
15	Subtotal Real Estate Tax				0	0	0	0	0	0	0	0	0	0	0
16	State Unemployment Tax	Unemployment Tax			386	0	22,921	21,404		1,903		7,241			15,680
17	Subtotal Unemployment Tax				386	0	22,921	21,404	0	1,903	0	7,241	0	0	15,680
18	Sales & Use Tax	Sales And Use Tax			2,165,812	0	32,491,244	29,759,320		4,897,736		0			32,491,244
19	Gross Receipts & Sales Tax	Sales And Use Tax			6,116	0	120,955	117,236		9,835		120,955			0

20	Subtotal Sales And Use Tax				2,171,928	0	32,612,199	29,876,556	0	4,907,571	0	120,955	0	0	32,491,244
21	Entergy Services, LLC	Income Tax			0	0				0	0	3,523,934			(3,523,934)
22	Subtotal Income Tax				0	0	0	0	0	0	0	3,523,934	0	0	(3,523,934)
23	State Excise Tax	Excise Tax			0	0				0		168,078			(168,078)
24	Subtotal Excise Tax				0	0			0	0	0	168,078	0	0	(168,078)
25	Subtotal Fuel Tax				0	0	0	0	0	0	0	0	0	0	0
26	Subtotal Federal Insurance Tax				0	0	0	0	0	0	0	0	0	0	0
27	Capital Stock Franchise	Franchise Tax			0	0				0		750			(750)
28	Franchise Tax - Local	Franchise Tax			16,325,256	0	53,289,254	51,158,055		18,456,455		53,457,324			(168,070)
29	Subtotal Franchise Tax				16,325,256	0	53,289,254	51,158,055	0	18,456,455	0	53,458,074	0	0	(168,820)
30	Non Income Tax	Miscellaneous Other Tax			87,000	0				87,000					0
31	Subtotal Miscellaneous Other Tax				87,000	0	0	0	0	87,000	0	0	0	0	0
32	Subtotal Other Federal Tax				0	0	0	0	0	0	0	0	0	0	0
33	Subtotal Other State Tax				0	0	0	0	0	0	0	0	0	0	0
34	Subtotal Other Property Tax				0	0	0	0	0	0	0	0	0	0	0
35	Subtotal Other Use Tax				0	0	0	0	0	0	0	0	0	0	0
36	Subtotal Other Advalorem Tax				0	0	0	0	0	0	0	0	0	0	0
37	Subtotal Other License And Fees Tax				0	0	0	0	0	0	0	0	0	0	0
38	Subtotal Payroll Tax				0	0	0	0	0	0	0	0	0	0	0
39	Ad Valorem Tax	Ad Valorem Tax			74,915,003	0	88,885,359	77,330,466		86,469,896		82,205,148			6,680,211
40	Subtotal Advalorem Tax				74,915,003	0	88,885,359	77,330,466	0	86,469,896	0	82,205,148	0	0	6,680,211
41	Entergy Services, LLC	Other Allocated Tax			0	0				0		17,367,208			(17,367,208)
42	Subtotal Other Allocated Tax				0	0	0	0	0	0	0	17,367,208	0	0	(17,367,208)
43	Subtotal Severance Tax				0	0	0	0	0	0	0	0	0	0	0
44	Subtotal Penalty Tax				0	0	0	0	0	0	0	0	0	0	0
45	Subtotal Other Taxes And Fees				0	0	0	0	0	0	0	0	0	0	0
40	TOTAL				152,477,057	2,179,105	169,112,933	(68,526,185)	0	390,043,047	2,105,977	121,000,182	0	0	48,112,751

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%	26,069,176			411.4	1,201,284		24,867,892	49.14	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	26,069,176				1,201,284		24,867,892		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
47	OTHER TOTAL									
48	GRAND TOTAL	26,069,176				1,201,284		24,867,892		

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredInvestmentTaxCreditsAveragePeriodOfAllocationToIncome

Average lives are based on estimated composite useful lives of the properties and are subject to reconsideration each year.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Qualified Pension funded status - See Note 11 - Retirement, Other Postretirement Benefits, and Defined Contribution Plans	17,875,245	131, 182.3	69,619,330	1,478,088	(50,265,997)
2	Non-Qualified Pension funded status	1,196,728	131	121,927	492,069	1,566,870
3	Performance Unit Program	553,816	131	240,485	309,729	623,060
4	Misc non-operating reserve	3,463,593				3,463,593
5	Restricted Units Program	221,647	131	159,991	75,047	136,703
6	Other	(2,423)				(2,423)
7	Production Tax Credits proceeds, including accrued interest, received from affiliate				47,262,980	47,262,980
47	TOTAL	23,308,606		70,141,733	49,617,913	2,784,786

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	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										
16.2	Other										
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										

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	1,696,233,154	387,918,667	206,946,411		182.3/254	11,094,535	182.3/254	24,987,634		1,891,098,509
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,696,233,154	387,918,667	206,946,411			11,094,535		24,987,634		1,891,098,509
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,696,233,154	387,918,667	206,946,411			11,094,535		24,987,634		1,891,098,509
10	Classification of TOTAL										
11	Federal Income Tax	1,413,312,320	318,146,408	173,996,359		182.3/254	9,334,756	182.3/254	22,534,065		1,570,661,678
12	State Income Tax	282,920,834	69,772,259	32,950,052		182.3/254	1,759,779	182.3/254	2,453,569		320,436,831
13	Local Income Tax										

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Reg Asset Covid 19	8,566,868	35,231	987,106							7,614,994
4	Reg Asset-Securitization	12,820,083	6,929,912	5,247,553							14,502,442
5	Maint/Refueling Reserve	11,925,110	5,088,639	8,055,719							8,958,030
6	Solar & Nuclear PTCs Monetized		6,534,530	233,228							6,301,302
7	Income tax adjustment	30,053,991					182.3/254	5,894,532	182.3/254	4,944,257	29,103,716
8	Minimum Pension Liability	92,153,365					190	14,458,917	190	616,975	78,311,423
9	Bond Reacquisition Loss	4,542,066	11,128	311,768							4,241,425
10	Section 475 Adj	(2,157,763)	2,103,398	2,569,753							(2,624,118)
11	Reg Asset-MOARK	951,384	3,913	109,622							845,675
12	Misc Cap Costs	449,700	73,490	175,952							347,238
13	Reg Asset-30yr Retail	899,422	4,756	133,244							770,934
14	Prepaid Expenses	1,639,455	3,159,194	3,561,103							1,237,546
15	Nuclear Decom Liability	37,453,912	1,846,573	734,482							38,566,003
9	TOTAL Electric (Total of lines 3 thru 8)	199,297,593	25,790,763	22,119,530				20,353,449		5,561,232	188,176,609
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	199,297,593	25,790,763	22,119,530				20,353,449		5,561,232	188,176,609

20	Classification of TOTAL										
21	Federal Income Tax	162,921,567	21,536,114	18,511,940			182.3/190/254	15,470,700	182.3/190/254	4,324,387	154,799,428
22	State Income Tax	36,376,026	4,254,649	3,607,590			182.3/190/254	4,882,749	182.3/190/254	1,236,845	33,377,181
23	Local Income Tax										

NOTES

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	Certain Investments in Debt & Equity Securities: ANO 1 Qualified Fund - Valuation Acct	416,365,706	128	50,019,652	136,088,320	502,434,374
2	Certain Investments in Debt & Equity Securities: ANO 2 Qualified Fund - Valuation Acct	344,895,174	128	43,130,523	112,908,718	414,673,369
3	Energy Efficiency Rider - Over-Recovery 07-085-TF	24,728,520			5,304,338	30,032,858
4	Income Taxes	508,282,328	190, 282, 283, 411.1	42,287,053	32,820,033	498,815,308
5	Capacity Costs Recovery Rider - Over-Recovery	3,163,803			5,765,319	8,929,122
6	Customer advances - minimum billing				10,000,000	10,000,000
7	Unprotected Excess Accumulated Deferred Income Taxes - APSC Docket No. 18-014-TF - Amort period Feb 2025-Jan 2027		411.1	10,425,129	22,745,737	12,320,608
8	System Agreement Costs - Over Collection	58,016			7,721	65,737
9	Deferred Fuel Over-Recovery	45,099,640	557	53,355,429	8,255,789	
10	UPSA Global Settlement - Black Box Refund	8,177,319	254	8,255,789	78,470	
11	Other Postretirement Plans	35,168,373			3,605,721	38,774,094
12	MISO Financial Transmission Rights Mark-to-Market	1,472,789	175	932,343		540,446
13	Solar Production Tax Credits - Driver Solar Facility				1,673,063	1,673,063
14	Solar Production Tax Credits - Walnut Bend Solar Facility				2,118,022	2,118,022
15	Solar Production Tax Credits - West Memphis Solar Facility				1,044,960	1,044,960
41	TOTAL	1,387,411,668		208,405,918	342,416,211	1,521,421,961

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Electric Operating Revenues

- 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.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- 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.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- 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.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,064,748,246	999,640,649	7,970,273	7,708,687	612,255	608,363
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	¹⁵ 597,511,467	¹⁵ 571,573,802	5,641,294	5,593,630	100,567	99,777
5	Large (or Ind.) (See Instr. 4)	733,895,071	632,143,802	12,062,485	9,932,431	23,324	23,639
6	(444) Public Street and Highway Lighting	11,821,833	11,469,984	79,357	79,833	859	839
7	(445) Other Sales to Public Authorities	7,734,055	7,152,347	109,480	108,797	58	53
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,415,710,672	2,221,980,584	25,862,889	23,423,378	737,063	732,671
11	(447) Sales for Resale	204,009,216	163,989,965	6,256,517	5,891,505	1	1
12	TOTAL Sales of Electricity	2,619,719,888	2,385,970,549	32,119,406	29,314,883	737,064	732,672
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	2,619,719,888	2,385,970,549	32,119,406	29,314,883	737,064	732,672
15	Other Operating Revenues						
16	(450) Forfeited Discounts	10,488,342	10,069,252				
17	(451) Miscellaneous Service Revenues	¹⁶ 1,395,922	¹⁶ 1,476,715				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	11,872,304	11,424,119				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	¹⁶ 27,239,417	¹⁶ (63,242,278)				
22	(456.1) Revenues from Transmission of Electricity of Others	102,763,632	106,615,948				

23	(457.1) Regional Control Service Revenues	2,044,719	1,930,945				
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	155,804,336	68,274,701				
27	TOTAL Electric Operating Revenues	2,775,524,224	2,454,245,250				
Line 12, column (b) includes \$ of unbilled revenues.							
Line 12, column (d) includes MWH relating to unbilled revenues							

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Basis of classification of Commercial and Industrial Sales Account 442: (a) Industrial - Standard Classification Manual; (b) Commercial - all other business or professional activities of a non-manufacturing nature.

(b) Concept: MiscellaneousServiceRevenues

Revenues from returned check charges, AMI Remote Reconnection Fees, offset by draw draft credits.

(c) Concept: OtherElectricRevenue

Other Electric Revenues:	
Green Power Tariff	\$9,061,908
Unbilled Revenue - Includes 40,184 MWH	5,125,989
Net metering avoided cost	4,368,241
Solar Purchase Options	3,793,491
MISO Mkt Sch 11 Wholesale Dist Revenue	2,849,190
Sales and Use tax	707,060
Go Zero Option	471,108
Energy Efficiency Incentive Amortization	346,038
Little Rock Air Force Base	171,493
Annual Schedule 50 Billing	153,190
Southwestern Power Administration (SWPA) admin fees	146,594
Permit revenue	138,350
Searcy Service Fees	96,317
Cancel rebills - System Energy settlement bill credits	12,626
Vehicle Charging Station Sales	7,381
Trans Union contract revenue	219
Big River Steel MISO credits	(28,708)
Third Party Sales of Inventory	(181,070)
	<u>\$27,239,417</u>

(d) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Basis of classification of Commercial and Industrial Sales Account 442: (a) Industrial - Standard Classification Manual; (b) Commercial - all other business or professional activities of a non-manufacturing nature.

(g) Concept: MiscellaneousServiceRevenues

Revenues from returned check charges, AMI Remote Reconnection Fees, offset by draw draft credits.

(f) Concept: OtherElectricRevenue

Other Electric Revenues:	
Unbilled Revenue - Includes (180,722) MWH	\$8,705,016
Green Power Tariff	7,272,685
Net metering avoided cost	4,967,928
Solar Purchase Options	3,928,896
MISO Mkt Sch 11 Wholesale Dist Revenue	2,222,181
Sales and Use tax	689,541
Third Party Sales of Inventory	589,934
Little Rock Air Force Base	208,536
Southwestern Power Administration (SWPA) admin fees	146,594
Annual Schedule 50 Billing	103,547
Searcy Service Fees	94,056
Permit revenue	70,450
City of Hot Springs Land Easements	40,072
CIAC excess reimbursements	22,448
Trans Union contract revenue	255
Big River Steel MISO credits	16
Retail bill credits - System Energy settlement	(92,304,433)
	<u>(\$63,242,278)</u>

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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	MISO Sch 1 Sched/Sys Ctrl/Disp	524,106	982,763	1,534,934	2,034,502
2	MISO Sch 2 Reactive	1,769	1,769	1,769	10,217
46	TOTAL	525,875	984,532	1,536,703	2,044,719

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	RS Gen. Purpose Res.	7,886,953	609,904,623	609,709	12,936	0.0773
2	RS3 Gen. Purpose Res.	7,068	560,199	424	16,670	0.0793
3	RT Opt. Res. Time-of-Use	601	44,213	45	13,356	0.0736
4	RMT Res Energy Mgmt TOU	1,060	79,996	69	15,362	0.0755
5	L4 All Night Outdoor Lighting	74,591	9,312,313	2,008	37,147	0.1248
6	SGS Small General Service		(530)			
7	FA General Farm Service					
8	NDCR ANO Decommissioning Cost		(1,730)			
9	GGR Grand Gulf Rider		60,571,650			
10	ECR Energy Cost Recovery Rider		95,720,388			
11	PCA Production Costs Allocation R		(42,922)			
12	EECR Energy Efficiency Cost Rate		33,206,674			
13	SDR Storm Damage Rider		(2)			
14	MFA Municipal Franchise Adj		28,693,277			
15	FLCF Federal Litig Consult Fee		719,451			
16	CCR Capacity Cost Recovery Rider		(2,214,181)			
17	MISO		(42,650,411)			
18	IBRA Interim Base Rate Adjustment					
19	FRP Formula Rate Plan		277,322,552			
20	TA Tax Adjustment Rider		(6,476,635)			
21	IRCR Interim Restructuring Credit		(679)			
22	Miscellaneous					
41	TOTAL Billed Residential Sales	7,970,273	1,064,748,246	612,255	13,018	0.1336
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	7,970,273	1,064,748,246	612,255	13,018	0.1336

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	SG1 Small Gen. Service	3,003,527	216,012,213	92,993	32,298	0.0719
2	SG2 Small Gen. Service	14,662	936,482	33	444,303	0.0639
3	SG3 Small Gen. Service	798	47,196	7	114,000	0.0591
4	SG4 Small Gen. Service	8,619	600,684	28	307,821	0.0697
5	SG5 Small Gen Service	3	1,059	3	1,000	0.3530
6	SG6 Small Gen Service	6,543	316,057	39	167,769	0.0483
7	SG7 Small Gen. Service	9,987	689,290	610	16,372	0.0690
8	GT1 Opt. LGS Time-of-Use	351,058	18,534,390	273	1,285,927	0.0528
9	GT2 Opt. LGS Time-of-Use	29,336	1,449,245	8	3,667,000	0.0494
10	GT4 Opt. LGS Time-of-Use	22,424	948,570	6	3,737,333	0.0423
11	IG1 LGS TOU Interruptible	104,280	2,072,975	33	3,160,000	0.0199
12	IG2 LGS TOU Interruptible	10,078	180,473	1	10,078,000	0.0179
13	IG4 LGS TOU Interruptible	14,295	186,340	2	7,147,500	0.0130
14	LG1 Large Gen. Service	1,136,645	59,070,953	1,234	921,106	0.0520
15	LG2 Large Gen. Service	43,468	1,934,678	16	2,716,750	0.0445
16	LG3 Large Gen. Service	497	53,825	2	248,500	0.1083
17	LG4 Large Gen. Service	18,928	1,202,417	11	1,720,727	0.0635
18	LG6 Large Gen. Service	8,852	706,600	4	2,213,000	0.0798
19	IL1 LGS Interruptible	24,594	231,819	7	3,513,429	0.0094
20	IL4 LGS Interruptible	176,450	1,654,645	4	44,112,500	0.0094
21	IP4 LPS Interruptible	76,020	812,184	1	76,020,000	0.0107
22	LP1 Large Power Service	47,701	2,026,745	6	7,950,167	0.0425
23	LP2 Large Power Service	62,615	2,435,488	5	12,523,000	0.0389
24	LP4 Large Power Service	146,986	5,129,749	9	16,331,778	0.0349
25	PT1 Opt. LPS Time-of-Use	63,160	3,658,226	11	5,741,818	0.0579
26	PT2 Opt. LPS Time-of-Use	55,941	2,338,009	3	18,647,000	0.0418
27	PT4 Opt. LPS Time-of-Use	51,752	2,008,157	4	12,938,000	0.0388

28	IT4 LPS Time-of-Use Interruptib	15,697	237,715	1	15,697,000	0.0151
29	CTV Comm. Ant. & TV Amp.	31,668	2,393,314	3,333	9,501	0.0756
30	L4 All Night Outdoor Lighting	101,943	10,523,939	1,878	54,283	0.1032
31	CGS Cotton Ginning Service	2,767	203,713	2	1,383,500	0.0736
32	NDCR ANO Decommissioning Cost		991			
33	GGR Grand Gulf Rider		27,451,618			
34	ECR Energy Cost Recovery Rider		69,065,587			
35	PCA Production Costs Allocation R		(27,178)			
36	EECR Energy Efficiency Cost Rate		19,080,093			
37	SDR Storm Damage Rider					
38	MFA Municipal Franchise Adj		21,802,375			
39	FLCF Federal Litig Consult Fee		484,835			
40	CCR Capacity Cost Recovery Rider		(1,111,780)			
41	MISO Rider		(18,702,775)			
42	FRP Formula Rate Plan		144,373,403			
43	TA Tax Adjustment		(3,498,310)			
44	IRCR Interim Restructuring Credit		(4,811)			
45	C23 Cogeneration		269			
46	Miscellaneous					
41	TOTAL Billed Small or Commercial	5,641,294	597,511,467	100,567	56,095	0.1059
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	5,641,294	^(a) 597,511,467	100,567	56,095	0.1059

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

[a] Concept: SmallOrCommercialSalesElectricOperatingRevenue

Basis of classification of Commercial and Industrial Sales Account 442: (a) Industrial - Standard Classification Manual; (b) Commercial - all other business or professional activities of a non-manufacturing nature.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	FA General Farm Service	69,384	4,483,856	3,357	20,668	0.0646
2	FAC General Farm Service	99,556	8,353,596	1,457	68,329	0.0839
3	SG1 Small Gen. Service	508,790	37,907,531	9,126	55,752	0.0745
4	SG2 Small Gen. Service	43,726	3,106,146	42	1,041,095	0.0710
5	SG3 Small Gen. Service	3,887	210,886	25	155,480	0.0543
6	SG4 Small Gen. Service	40,791	2,555,239	33	1,236,091	0.0626
7	SG5 Small Gen. Service	23,101	2,775,177	5	4,620,200	0.1201
8	SG6 Small Gen. Service	4,226	315,574	1	4,226,000	0.0747
9	IS2 SGS Interruptible	190	14,312	1	190,000	0.0753
10	GT1 Opt. LGS Time-of-Use	98,570	5,229,473	44	2,240,227	0.0531
11	GT2 Opt. LGS Time-of-Use	17,466	885,533	4	4,366,500	0.0507
12	GT4 Opt. LGS Time-of-Use	33,834	1,704,659	13	2,602,615	0.0504
13	IG1 LGS TOU Interruptible	8,360	189,236	3	2,786,667	0.0226
14	IG3 LGS TOU Interruptible	4,764	80,997	1	4,764,000	0.0170
15	IG4 LGS TOU Interruptible	7,809	161,551	2	3,904,500	0.0207
16	LG1 Large Gen. Service	528,932	28,281,365	355	1,489,949	0.0535
17	LG2 Large Gen. Service	96,775	4,737,340	28	3,456,250	0.0490
18	LG3 Large Gen. Service	785	43,913	1	785,000	0.0559
19	LG4 Large Gen. Service	219,556	9,072,462	65	3,377,785	0.0413
20	LG5 Large Gen. Service	7,205	401,407	3	2,401,667	0.0557
21	LG6 Large Gen. Service	1,242	95,749	1	1,242,000	0.0771
22	IL1 LGS Interruptible	62,337	1,000,548	15	4,155,800	0.0161
23	IL2 LGS Interruptible	16,042	234,837	3	5,347,333	0.0146
24	IL4 LGS Interruptible	122,408	1,557,159	4	30,602,000	0.0127
25	LP1 Large Power Service	183,048	8,563,394	26	7,040,308	0.0468
26	LP2 Large Power Service	745,862	33,455,262	42	17,758,619	0.0449
27	LP4 Large Power Service	1,952,760	64,824,155	55	35,504,727	0.0332

28	LP5 Large Power Service	71,612	2,695,723	5	14,322,400	0.0376
29	LP6 Large Power Service	28,595	1,106,814	2	14,297,500	0.0387
30	LPHLD4 Large Power High-Load Density Service	2,022,904	38,790,069	25	80,916,160	0.0192
31	IP4 LPS Interruptible	637,614	10,715,962	5	127,522,800	0.0168
32	IP6 LPS Interruptible	169,730	2,070,427	1	169,730,000	0.0122
33	PT1 Opt. LPS Time-of-Use	65,095	3,541,799	9	7,232,778	0.0544
34	PT2 Opt. LPS Time-of-Use	44,352	1,905,383	3	14,784,000	0.0430
35	PT4 Opt. LPS Time-of-Use	173,143	6,457,785	11	15,740,273	0.0373
36	IT1 LPS TOU Interruptible	5,592	121,763	1	5,592,000	0.0218
37	IT4 LPS TOU Interruptible	58,688	2,705,164	1	58,688,000	0.0461
38	IT6 LPS TOU Interruptible	3,525,564	108,998,548	3	1,175,188,000	0.0309
39	APA Agricultural Water Pump Svc	220,128	18,309,824	5,820	37,823	0.0832
40	APB Agricultural Water Pump Svc	63,991	6,715,106	2,509	25,505	0.1049
41	CGS Cotton Ginning Service	42,495	3,002,677	30	1,416,500	0.0707
42	L4 All Night Outdoor Lighting	13,322	1,339,691	184	72,402	0.1006
43	SS Standby Service	18,254	1,778,912			0.0975
44	C23 Cogeneration		807	3		
45	NDCR ANO Decommissioning Cost		257			
46	GGR Grand Gulf Rider		29,709,354			
47	ECR Energy Cost Recovery Rider		147,591,333			
48	PCA Production Costs Allocation R		(44,966)			
49	EECR Energy Efficiency Cost Rate		19,266,460			
50	MFA Municipal Franchise Adj		2,941,357			
51	FLCF Federal Litig Consult Fee		1,028,067			
52	CCR Capacity Cost Recovery Rider		(1,201,566)			
53	MISO Rider		(28,999,095)			
54	FRP Formula Rate Plan		136,856,094			
55	TA Tax Adjustment Rider		(3,750,569)			
56	IRCR Interim Restructuring Credit		534			
57	SDR Storm Damage Rider					
58	Miscellaneous					
41	TOTAL Billed Large (or Ind.) Sales	12,062,485	733,895,071	23,324	517,171	0.0608
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	12,062,485	733,895,071	23,324	517,171	0.0608

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	L1 Municipal Street Lighting	72,570	6,571,911	306	237,157	0.0906
2	L1SH Municipal Shielded Street Li	116	14,517	2	58,000	0.1251
3	L2 Traffic Signal Service	6,070	516,437	486	12,490	0.0851
4	L4 All Night Outdoor Lighting	306	30,018	64	4,781	0.0981
5	LEDSL Municipal Street Lighting	295	20,584	1	295,000	0.0698
6	NDCR ANO Decommissioning Cost		120			
7	GGR Grand Gulf Rider		673,523			
8	ECR Energy Cost Recovery Rider		962,681			
9	PCA Production Costs Allocation R		(453)			
10	EECR Energy Efficiency Cost Rate		224,067			
11	MFA Municipal Franchise Adj		16,742			
12	FLCF Federal Litig Consult Fee		7,026			
13	CCR Capacity Cost Recovery Rider		(11,330)			
14	MISO Rider		(118,481)			
15	FRP Formula Rate Plan		2,981,034			
16	TA Tax Adjustment Rider		(66,053)			
17	IRCR Interim Restructuring Credit		(510)			
41	TOTAL Billed Public Street and Highway Lighting	79,357	11,821,833	859	92,383	0.1490
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	79,357	11,821,833	859	92,383	0.1490

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	SG1 Small Gen. Service	1,269	90,094	35	36,257	0.0710
2	GT1 Opt. LGS Time-of-Use	7	9,310			1.3300
3	LG1 Large Gen. Service	17	1,691			0.0995
4	LP2 Large Power Service	80,816	3,135,522	1	80,816,000	0.0388
5	PT4 Opt. LPS Time-of-Use	26,824	1,148,808	1	26,824,000	0.0428
6	L4 All Night Outdoor Lighting	14	1,781	1	14,000	0.1272
7	MP Municipal Pump Service	533	35,875	20	26,650	0.0673
8	NDCR ANO Decommissioning Cost		3			
9	GGR Grand Gulf Rider		250,052			
10	ECR Energy Cost Recovery Rider		1,334,138			
11	PCA Production Costs Allocation R		(453)			
12	EECR Energy Efficiency Cost Rate		92,136			
13	MFA Municipal Franchise Adj		3,502			
14	FLCF Federal Litig Consult Fee		9,309			
15	CCR Capacity Cost Recovery Rider		(10,044)			
16	MISO Rider		(207,218)			
17	FRP Formula Rate Plan		1,875,560			
18	IRCR Interim Restructuring Credit		(13)			
19	TA Tax Adjustment Rider		(35,998)			
41	TOTAL Billed Other Sales to Public Authorities	109,480	7,734,055	58	1,887,586	0.0706
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	109,480	7,734,055	58	1,887,586	0.0706

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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)
41	TOTAL Billed - All Accounts	25,862,889	2,415,710,672	737,063	35,089	0.0934
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts	25,862,889	2,415,710,672	737,063	35,089	0.0934

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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SALES FOR RESALE (Account 447)

- 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).
- Enter the name of the purchaser 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 purchaser.
- 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 long-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 seller 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.
- 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).
- 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.
- 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.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- 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.
- 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.
- 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	^(a) Entergy Louisiana, LLC	LU					683,093	26,524,774	6,245,265		32,770,039
2	^(a) Entergy Mississippi, LLC	IU	94				544,212	26,732,185	3,286,077		30,018,262
3	^(a) Entergy New Orleans, LLC	LU	94				685,303	26,519,837	6,318,798		32,838,635
4	^(a) Entergy Power, LLC	OS	123				0		89,129		89,129
5	^(a) Conway Corporation	OS	98				0		31,886		31,886
6	^(a) Jonesboro City Light & Water	OS	151				0		141,738		141,738
7	^(a) City of Osceola	OS	101				0		5,006		5,006
8	^(a) City of West Memphis	OS	99				0		15,943		15,943
9	^(a) Arkansas Electric Cooperative Corp.	OS	82	59	51	51	0		558,001	497,037 ^(a)	1,055,038

10	East Texas Electric Cooperative	OS	147				0		44,223		44,223
11	Entergy Mississippi, LLC	OS					0		250,298		250,298
12	Associated Electric Coop., Inc.	RQ	130				(200)	1,557	6,010		7,567
13	Midcontinent ISO, Inc.	OS					4,344,109	12,573,156	93,213,068	955,228	106,741,452
15	Subtotal - RQ						(200)	1,557	6,010		7,567
16	Subtotal-Non-RQ						6,256,717	92,349,952	110,199,432	1,452,265	204,001,649
17	Total						6,256,517	92,351,509	110,205,442	1,452,265	204,009,216

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

- (a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Energy and capacity sales associated with MSS-4 from January 2025 through December 2025.
- (b) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Energy and capacity sales associated with MSS-4 from January 2025 through September 2025.
- (c) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Energy and capacity sales associated with MSS-4 from January 2025 through December 2025.
- (d) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (e) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (f) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (g) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (h) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (i) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (j) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (k) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.
- (l) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Sales provided under a letter agreement effective March 1992.
- (m) Concept: OtherChargesRevenueSalesForResale
Related to wholesale distribution and capital credit refunds
- (n) Concept: OtherChargesRevenueSalesForResale

CHARGES	
MISO Ancillary	(\$665,092)
MISO Residual Load	3,225,891
MISO Uplift	(1,717,005)
MISO Scarcy Revenue	111,434
Total Other Purchases from MISO	\$955,228

Name of Respondent: Energy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	4,233,474	3,587,692
5	(501) Fuel	326,993,367	229,271,326
6	(502) Steam Expenses	3,419,796	2,953,001
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,283,300	1,163,153
10	(506) Miscellaneous Steam Power Expenses	6,644,423	6,319,337
11	(507) Rents	53,160	100,009
12	(509) Allowances	14	47
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	342,627,534	243,394,565
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	538,292	317,239
16	(511) Maintenance of Structures	1,810,004	1,298,862
17	(512) Maintenance of Boiler Plant	11,146,571	6,053,799
18	(513) Maintenance of Electric Plant	6,001,743	5,495,243
18.1	(513.1) Maintenance of Computer Hardware	98,456	
18.2	(513.2) Maintenance of Computer Software	1,181,854	
18.3	(513.3) Maintenance of Communication Equipment		
19	(514) Maintenance of Miscellaneous Steam Plant	2,538,301	2,256,783
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,315,221	15,421,926
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	365,942,755	258,816,491
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	32,685,575	31,634,199
25	(518) Fuel	100,099,779	83,924,201
26	(519) Coolants and Water	8,406,717	7,755,901
27	(520) Steam Expenses	41,605,418	40,489,632

28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	42,685,978	42,583,068
32	(525) Rents	1,024,794	1,179,593
33	TOTAL Operation (Enter Total of lines 24 thru 32)	226,508,261	207,566,594
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	16,810,331	18,030,800
36	(529) Maintenance of Structures	1,194	110,035
37	(530) Maintenance of Reactor Plant Equipment	1,537,953	1,643,485
38	(531) Maintenance of Electric Plant	12,117,786	12,312,828
38.1	(531.1) Maintenance of Computer Hardware	27,196	
38.2	(531.2) Maintenance of Computer Software	1,022,218	
38.3	(531.3) Maintenance of Communication Equipment	391,174	
39	(532) Maintenance of Miscellaneous Nuclear Plant	77,669,192	88,144,574
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	109,577,044	120,241,722
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 & 40)	336,085,305	327,808,316
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	207,926	139,897
45	(536) Water for Power	383,015	593,372
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	560	783,872
48	(539) Miscellaneous Hydraulic Power Generation Expenses	416,544	262,592
49	(540) Rents		9,205
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,008,045	1,788,938
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	65	
54	(542) Maintenance of Structures	59,207	59,205
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,640,202	1,132,214
56	(544) Maintenance of Electric Plant	442,038	396,113
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment		
57	(545) Maintenance of Miscellaneous Hydraulic Plant	506,178	501,089

58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,647,690	2,088,621
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	3,655,735	3,877,559
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	4,862,775	4,102,031
63	(547) Fuel		
64	(548) Generation Expenses	3,355,104	3,320,423
65	(549) Miscellaneous Other Power Generation Expenses	8,836,191	11,091,025
66	(550) Rents	38,102	41,503
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	17,092,172	18,554,982
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	897,226	806,702
70	(552) Maintenance of Structures	328,881	2,114,227
71	(553) Maintenance of Generating and Electric Plant	9,836,322	9,059,216
71.1	(553.1) Maintenance of Computer Hardware	37,221	
71.2	(553.2) Maintenance of Computer Software	135,891	
71.3	(553.3) Maintenance of Communication Equipment	2	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	621,151	462,565
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	11,856,694	12,442,710
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	28,948,866	30,997,692
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	247,389,653	241,206,026
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits	31,962	
76.3	(555.3) Unbundled Environmental Credits		
77	(556) System Control and Load Dispatching	1,575,942	1,412,091
78	(557) Other Expenses	(74,284,477)	(38,813,815)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	174,713,080	203,804,302
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	1,190,627	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	4,909,292	
79.6	(558.4) Rents	1,391,882	
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	7,491,801	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		

79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment	5,702,770	
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software	1,451	
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	5,704,221	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	13,196,022	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses	665,895	
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)	665,895	
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)	665,895	
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		

79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	923,207,658	825,304,360
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,081,376	4,306,041
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,287,314	3,286,852
87	(561.3) Load Dispatch-Transmission Service and Scheduling	61,605	62,024
88	(561.4) Scheduling, System Control and Dispatch Services	9,835,672	7,355,098
89	(561.5) Reliability, Planning and Standards Development	862,668	868,777
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	848,237	1,041,238
93	(562) Station Expenses	341,103	310,527
94	(563) Overhead Lines Expenses	2,630,950	4,017,119
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	861,858	822,424
97	(566) Miscellaneous Transmission Expenses	5,046,401	7,056,323
98	(567) Rents	59,971	133,708
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	28,917,155	29,260,131
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	7,833,346	6,020,574
102	(569) Maintenance of Structures	116,619	130,962
103	(569.1) Maintenance of Computer Hardware	21,444	
104	(569.2) Maintenance of Computer Software	1,584,626	67,269
105	(569.3) Maintenance of Communication Equipment	38,763	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,206,081	3,444,239
108	(571) Maintenance of Overhead Lines	4,945,777	4,236,814
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	55,826	37,806
111	TOTAL Maintenance (Total of Lines 101 thru 110)	18,802,482	13,937,664
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	47,719,637	43,197,795

113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	5,332,355	4,859,757
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	5,332,355	4,859,757
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	5,332,355	4,859,757
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		

133	Operation		
134	(580) Operation Supervision and Engineering	23,381,741	21,360,463
135	(581) Load Dispatching	492,449	495,446
136	(582) Station Expenses	389,743	401,436
137	(583) Overhead Line Expenses	1,902,077	1,597,690
138	(584) Underground Line Expenses	3,454,446	3,501,543
139	(585) Street Lighting and Signal System Expenses	635,330	597,679
140	(586) Meter Expenses	3,127,790	2,458,647
141	(587) Customer Installations Expenses	1,561,954	1,430,030
142	(588) Miscellaneous Expenses	5,988,140	8,675,302
143	(589) Rents	1,232,660	1,455,677
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	42,166,330	41,973,913
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,127,651	2,814,480
147	(591) Maintenance of Structures	1,738,490	1,773,618
148	(592) Maintenance of Station Equipment	2,906,123	2,364,268
148.1	(592.2) Maintenance of Computer Hardware	5,647	
148.2	(592.3) Maintenance of Computer Software	2,987,208	
148.3	(592.4) Maintenance of Communication Equipment	179,419	
149	(593) Maintenance of Overhead Lines	55,187,069	45,345,040
150	(594) Maintenance of Underground Lines	2,185,633	3,480,546
151	(595) Maintenance of Line Transformers	107,441	203,805
152	(596) Maintenance of Street Lighting and Signal Systems	1,509,601	2,007,808
153	(597) Maintenance of Meters	496,331	309,825
154	(598) Maintenance of Miscellaneous Distribution Plant	1,745,904	2,449,348
155	TOTAL Maintenance (Total of Lines 146 thru 154)	71,176,517	60,748,738
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	113,342,847	102,722,651
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	798,480	672,220
160	(902) Meter Reading Expenses	1,918,931	2,328,470
161	(903) Customer Records and Collection Expenses	22,022,876	23,575,247
162	(904) Uncollectible Accounts	17,175,513	10,886,487
163	(905) Miscellaneous Customer Accounts Expenses	23,461	105,207
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	41,939,261	37,567,631
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		

166	Operation		
167	(907) Supervision	389,718	518,111
168	(908) Customer Assistance Expenses	66,418,255	78,643,776
169	(909) Informational and Instructional Expenses	603,538	689,072
170	(910) Miscellaneous Customer Service and Informational Expenses	1,900,773	1,777,585
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	69,312,284	81,628,544
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision	208,370	12,564
175	(912) Demonstrating and Selling Expenses	3,145,741	2,929,899
176	(913) Advertising Expenses	123,183	47,428
177	(916) Miscellaneous Sales Expenses	807,257	993,160
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	4,284,551	3,983,051
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	50,786,574	60,966,434
182	(921) Office Supplies and Expenses	5,336,851	4,936,677
183	(Less) (922) Administrative Expenses Transferred-Credit	4,059,328	4,707,441
184	(923) Outside Services Employed	9,783,941	25,716,757
185	(924) Property Insurance	33,075,080	32,091,711
186	(925) Injuries and Damages	10,226,577	7,902,326
187	(926) Employee Pensions and Benefits	62,273,480	57,739,334
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,060,207	5,175,328
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	351,080	438,804
192	(930.2) Miscellaneous General Expenses	(2,559,337)	5,936,496
193	(931) Rents	1,153,720	645,202
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	173,428,845	196,841,628
195	Maintenance		
196	(935) Maintenance of General Plant	434,712	1,567,605
196.1	(935.1) Maintenance of Computer Hardware	2,787,962	
196.2	(935.2) Maintenance of Computer Software	21,798,708	
196.3	(935.3) Maintenance of Communication Equipment	3,568,370	
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	28,589,752	1,567,605
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	202,018,597	198,409,233

198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	1,407,157,190	1,297,673,022
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Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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PURCHASED POWER (Account 555)

- 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.
- 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.
- 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.

- 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.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (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.
- 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.
- 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.
- 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.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)	
1	^(a) System Energy Resources, Inc.	OS					3,494,459					170,127,955	21,235,887	(6,002,214) ⁽ⁿ⁾	185,361,628
2	Midcontinent ISO, Inc.	OS	OATT				1,746,701					814,801	78,268,193	(46,367,429) ⁽ⁿ⁾	32,715,565
3	Stuttgart Solar, LLC	OS					152,811						8,264,033		8,264,033
4	Chicot Solar, LLC	OS					214,871						6,050,940		6,050,940
5	Flat Fork Solar	OS					127,581						5,259,876		5,259,876
6	Forgeview Solar	OS					8,004						362,028		362,028
7	Karbone	OS										26,244			26,244
8	North Little Rock Electric Dept.	OS					277						15,981		15,981
9	Little Rock Wastewater	OS	M23				3						99		99

10	West Memphis	OS	99				4,581				159,396	344,393		503,789
11	Capacity Deferrals	OS											(5,765,319)	5,765,319
12	Searcy	OS											(1,338,108)	(1,338,108)
13	Small Residential Generation	OS					178,999					4,402,259		4,402,259
15	TOTAL						5,928,287	0	0	0	171,128,396	124,203,689	(47,942,432)	247,389,653

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy and capacity charges from Grand Gulf Nuclear Power Plant.

(b) Concept: OtherChargesOfPurchasedPower

Represents (\$1,891,472) for the deferral on over/under recovery under the Grand Gulf Rider and (\$4,110,742) for the turnaround of the Grand Gulf Accelerated Recovery Tariff approved by the FERC that provided for the acceleration of Entergy Arkansas's Grand Gulf purchased power obligations with System Energy Resources.

(c) Concept: OtherChargesOfPurchasedPower

CHARGES	
MISO Ancillary	\$2,704,711
MISO Congestion	(54,344,021)
MISO Losses	(5,615,903)
MISO Uplift	9,589,015
MISO Residual Load	698,011
MISO Administration	600,758
Total Other Purchases from MISO	<u>(\$46,367,429)</u>

(d) Concept: OtherChargesOfPurchasedPower

Deferral of capacity related to West Memphis and MISO Capacity Auction Revenues.

(e) Concept: OtherChargesOfPurchasedPower

Cost of power paid for under the contract for difference associated with Searcy Solar.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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).
- 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.
- 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.
- 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.
- 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.
- Report in column (i) and (j) the total megawatthours received and delivered.
- 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.
- 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.
- Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	MISO	Various	Various			Various	Various					102,763,632		102,763,632
35	TOTAL							0	0	0		102,763,632		102,763,632

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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					
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47					
48					
49					
40	TOTAL				

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

- 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.
- 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.
- 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.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- 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. In 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.
- Enter "TOTAL" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Associated Electric Cooperative Inc.				373,895			373,895
2	Southwestern Power Administration				301,698			301,698
3	Midcontinent Independent System Operator Inc						186,265	186,265
	TOTAL		0	0	675,593	0	186,265	861,858

FOOTNOTE DATA

(a) Concept: DemandChargesTransmissionOfElectricityByOthers

These expenses represent the charges incurred from a third party for the utilization of its transmission system by Entergy Arkansas. These transmission expenses are associated with either a sale of bulk power to an external company or a purchase of bulk power from an external company.

(b) Concept: DemandChargesTransmissionOfElectricityByOthers

Respondent delivers energy to Water Valley, Arkansas, and Southwestern Power Administration wheels energy to Respondent's customers at Ash Flat, Arkansas.

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

Network upgrade charges incurred from MISO under the MISO Attachment O. Rates are calculated under Attachment GG. Charges are related to the MTEP (MISO Transmission Expansion Plan).

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	783,898
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhdrs...expn servicing outstanding Securities	663,615
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	5% surcharge on regulated billings to non-regulated affiliates	(52,204)
7	Federal infrastructure policy support	16,024
8	Irrigation load control amortization	685,969
9	Regulatory support	48,495
10	Co-owner credits - Independence	(3,109,792)
11	Co-owner credits - White Bluff	(1,675,386)
12	Directors meetings and expenses	9,536
13	Transportation	110,578
14	Other	(40,070)
46	<u>TOTAL</u>	(2,559,337)

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- 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).
- 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.
- 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.
- 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			155,145		155,145
2	Steam Production Plant	14,449,773	2,828,042			17,277,815
3	Nuclear Production Plant	102,880,748	8,471,810			111,352,558
4	Hydraulic Production Plant-Conventional	1,073,474	(2,188)			1,071,286
5	Hydraulic Production Plant-Pumped Storage					
5.1	Solar Production Plant	21,825,373				21,825,373
5.2	Wind Production Plant					
5.3	Other Renewable Production Plant					
6	Other Production Plant	40,012,283	807,425			40,819,708
7	Transmission Plant	53,182,169				53,182,169
8	Distribution Plant	159,708,901				159,708,901
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant					
10	General Plant	58,276,946				58,276,946
11	Common Plant-Electric					
12	TOTAL	451,409,667	12,105,089	155,145		463,669,901

B. Basis for Amortization Charges

Entergy amortizes its intangible plant on a straight-line basis over the useful life of the assets. The same methodology is applied for both its retail and FERC-jurisdictional rates and no year over year change in basis or rate is expected. As of December 31, 2025, Entergy Arkansas' plant included intangible plant with 3, 5, 10, 15, and 20 year lives, as well as End of Life assets tied to the license end date of Arkansas Nuclear One. Additionally, Entergy Arkansas' plant included a 50-year life asset and a 30-year life asset for Franchised Consents included in Account 302.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: AmortizationOfLimitedTermPlantOrProperty Includes \$19 of service company amortization billing allocations.
(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments Includes \$8,544,505 of service company depreciation billing allocations.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO				Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)			
1	FEDERAL ENERGY REGULATORY COMMISSION											
2	Other expenses incurred in connection with MISO and other transmission related FERC dockets		125,617	125,617		Electric	928	125,617				
3	Other expenses incurred in connection with various filings before the FERC		25,321	25,321		Electric	928	25,321				
4	MSS-4 Depreciation Rate Update - FERC Docket ER26-263		20,077	20,077		Electric	928	20,077				
5	Attachment O Depreciation Rate Update - FERC Docket ER26-408 (Note - Transmission related)		7,141	7,141		Electric	928	7,141				
6	FERC Audit FA25-2-000 (Note - Includes Transmission)		539,876	539,876		Electric	928	539,876				
7	Federal Litigation Consulting Fees - FERC Docket EL20-72 SERI UPSA; Opp Sales DC Circuit (recovered through rate rider)		2,307,776	2,307,776	1,878,889	Electric	928	511,563			1,796,213	82,676
8	ARKANSAS PUBLIC SERVICE COMMISSION											
9	APSC - Docket No. 16-036-FR EAI Formula Rate Plan		1,252,574	1,252,574		Electric	928	1,252,574				
10	2026 Rate Case incremental costs - APSC Docket 26-001-U					Electric	928	398,338	398,338			398,338
11	2026 Rate Case APSC Docket 26-001-U		1,219,081	1,219,081		Electric	928	1,219,081				
12	Other expenses incurred in connection with various filings before the APSC		1,562,744	1,562,744		Electric	928	1,562,744				
46	TOTAL		7,060,207	7,060,207	1,878,889			5,662,332	398,338		1,796,213	481,014

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
 Classifications:

Electric R, D and D Performed Internally: Generation hydroelectric Recreation fish and wildlife Other hydroelectric Fossil-fuel steam Internal combustion or gas turbine Nuclear Solar Wind Other renewable Unconventional generation Siting and heat rejection	Transmission Overhead Underground Distribution Regional Transmission and Market Operation Energy Storage Environment (other than equipment) Other (Classify and include items in excess of \$50,000.) Total Cost Incurred Electric, R, D and D Performed Externally: Research Support to the electrical Research Council or the Electric Power Research Institute Research Support to Edison Electric Institute Research Support to Nuclear Power Groups Research Support to Others (Classify) Total Cost Incurred
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3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged in Current Year: Account (e)	Amounts Charged in Current Year: Amount (f)	
1	A(2)	Transmission Design and Planning	50,708		107	50,708	
2	B(1)	EPRI dues		22,916	930.2	22,916	
3	B(1)	EPRI 1		191,830	580	191,830	
4	B(1)	EPRI 2		1,608,413	517	1,608,413	
5	B(1)	EPRI 3		593,282	506	593,282	
6	B(1)	EPRI 4		151,136	560	151,136	
7	B(2)	Edison Electric Institute		416,117	930.2	416,117	
8	B(4)	SERC		1,154,610	561.8	1,154,610	
9	B(4)	Nuclear Design Improvements		10,000	517	10,000	
10	B(4)	North American Transmission Forum Inc		78,616	560	78,616	
11	B(3)	Nuclear Energy Institute dues		814,733	517	814,733	
12	B(4)	Distribution University Research		12,095	580	12,095	

Name of Respondent: Energy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	104,843,548		
4	Transmission	7,616,944		
5	Regional Market			
5.1	Energy Storage			
6	Distribution	21,725,460		
7	Customer Accounts	8,168,280		
8	Customer Service and Informational	5,637,280		
9	Sales	1,728,421		
10	Administrative and General	46,730,791		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	196,450,724		
12	Maintenance			
13	Production	58,663,292		
14	Transmission	6,924,926		
15	Regional Market			
15.1	Energy Storage			
16	Distribution	12,037,091		
17	Administrative and General	4,548,924		
18	TOTAL Maintenance (Total of lines 13 thru 17)	82,174,233		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	163,506,840		
21	Transmission (Enter Total of lines 4 and 14)	14,541,870		
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)	33,762,551		
24	Customer Accounts (Transcribe from line 7)	8,168,280		
25	Customer Service and Informational (Transcribe from line 8)	5,637,280		
26	Sales (Transcribe from line 9)	1,728,421		

27	<u>Administrative and General (Enter Total of lines 10 and 17)</u>		51,279,715	
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)		278,624,957	278,624,957
29	<u>Gas</u>			
30	<u>Operation</u>			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	<u>Other Gas Supply</u>			
34	<u>Storage, LNG Terminaling and Processing</u>			
35	<u>Transmission</u>			
36	<u>Distribution</u>			
37	<u>Customer Accounts</u>			
38	<u>Customer Service and Informational</u>			
39	<u>Sales</u>			
40	<u>Administrative and General</u>			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	<u>Maintenance</u>			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	<u>Other Gas Supply</u>			
46	<u>Storage, LNG Terminaling and Processing</u>			
47	<u>Transmission</u>			
48	<u>Distribution</u>			
49	<u>Administrative and General</u>			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	<u>Total Operation and Maintenance</u>			
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	<u>Administrative and General (Lines 40 and 49)</u>			
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)		278,624,957	278,624,957
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant		130,443,903	130,443,903
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)		130,443,903	130,443,903
72	Plant Removal (By Utility Departments)			
73	Electric Plant		8,004,813	8,004,813
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)		8,004,813	8,004,813
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	NUCLEAR FUEL-CAPITAL LEASES (Account 120)		354,649	354,649
80	Fuel Stock Exp Undistributed (Account 152)		6,250,899	6,250,899
81	PLANT MATLS AND OPERATING SUP (Account 154)		31,946	31,946
82	Stores Expense Undistributed (Account 163)		9,618,877	9,618,877
83	Miscellaneous Current and Accrued Assets (Account 174)		10,297,521	10,297,521
84	UNAMORTIZED DEBT EXPENSE (Account 181)		9,335	9,335
85	PRELIMINARY SURVEY & INVTG CH (Account 183)		949,255	949,255
86	Clearing Accounts (Account 184)		4,274,556	4,274,556
87	Miscellaneous Deferred Debits (Account 186)		869,758	869,758
88	Accumulated Provisions for Property Insurance (Account 2281)		12,163,035	12,163,035
89	Expenses-Nonutility Oper (Account 4171)		21,596	21,596
90	MISC NONOPERATING INCOME (Account 421)		76	76
91	DONATIONS (Account 4261)		246,487	246,487
92	Civil, Political, and Related Expenses (Account 4264)		1,170,541	1,170,541
93	Other Deductions (Account 4265)		10,585,569	10,585,569
94				
95	TOTAL Other Accounts		56,844,100	56,844,100
96	TOTAL SALARIES AND WAGES		473,917,773	473,917,773

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: SalariesAndWagesGeneralExpense
The payroll included in this page includes payroll billed from affiliates.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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.

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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, Purchase 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)	29,194,840	38,411,644	57,690,377	78,268,193
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	6,554,336	51,608,508	75,811,924	93,213,068
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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45					
46	TOTAL	35,749,176	90,020,152	133,502,301	171,481,261

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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						2,034,502
2	Reactive Supply and Voltage						10,217
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						2,044,719 ^(a)

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: AncillaryServicesSoldAmount

Entergy Arkansas is a transmission owning member of Midcontinent Independent Transmission System Operator (MISO) RTO. Entergy Arkansas does not purchase or sell transmission services or ancillary services directly. Instead, Entergy Arkansas receives revenues and incurs expenses from transmission services and ancillary sold by MISO. MISO distributes the revenue that it receives to the transmission owner and the transmission owner pays MISO for the related expenses incurred.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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: Entergy Arkansas, LLC										
1	January	6,872	22	8	4,034	2,838					
2	February	6,954	20	9	3,806	3,148					
3	March	5,064	6	9	3,025	2,039					
4	Total for Quarter 1				10,865	8,025	0	0	0	0	
5	April	5,199	28	16	3,201	1,998					
6	May	5,591	14	18	3,454	2,137					
7	June	7,198	25	15	4,429	2,769					
8	Total for Quarter 2				11,084	6,904	0	0	0	0	
9	July	7,876	22	17	4,772	3,104					
10	August	7,604	18	15	4,654	2,950					
11	September	6,847	12	17	4,411	2,436					
12	Total for Quarter 3				13,837	8,490	0	0	0	0	
13	October	5,728	2	16	3,396	2,332					
14	November	5,949	11	8	3,730	2,219					
15	December	7,110	15	9	4,369	2,741					
16	Total for Quarter 4				11,495	7,292	0	0	0	0	
17	Total				47,281	30,711	0	0	0	0	

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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									0
2	February									0
3	March									0
4	Total for Quarter 1				0	0	0	0	0	0
5	April									0
6	May									0
7	June									0
8	Total for Quarter 2				0	0	0	0	0	0
9	July									0
10	August									0
11	September									0
12	Total for Quarter 3				0	0	0	0	0	0
13	October									0
14	November									0
15	December									0
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-03	Year/Period of Report End of: 2025/ Q4
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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)	25,862,889
3	Steam	11,515,636	23	Requirements Sales for Resale (See instruction 4, page 311.)	(200)
4	Nuclear	15,191,934	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,256,717
5	Hydro-Conventional	193,679	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	41,051
6.1	Solar	1,079,749	27	Total Energy Losses	1,748,828
6.2	Wind		27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	33,909,285
7	Other				
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	27,980,998			
10	Purchases (other than for Energy Storage)	5,928,287			
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)	33,909,285			

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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: Entergy Arkansas, LLC					
29	January	3,009,322	496,805	4,565	22	8
30	February	2,354,504	244,245	4,463	20	8
31	March	2,286,104	314,041	3,527	6	9
32	April	2,616,493	681,830	3,595	28	17
33	May	2,982,312	911,252	3,914	14	18
34	June	3,297,880	802,501	4,860	25	15
35	July	3,605,336	688,172	5,250	22	17
36	August	3,480,541	783,988	5,219	18	15
37	September	2,780,987	389,486	4,587	12	17
38	October	2,363,713	212,488	3,914	7	15
39	November	2,406,978	419,701	3,841	11	8
40	December	2,725,115	312,208	4,587	15	9
41	Total	33,909,285	6,256,717			

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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: Arkansas Nuclear One (Units 1 and 2)	Plant Name: Hot Spring	Plant Name: ^(b) Independence	Plant Name: ^(b) Lake Catherine	Plant Name: ^(b) Ouachita 1 & 2	Plant Name: ^(b) Union Power Station	Plant Name: ^(b) White Bluff
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Nuclear	Gas Turbine	Steam	Steam	Gas Turbine	Combined Cycle	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	N/A	Outdoor	Full Outdoor	Full Outdoor	Outdoor	Outdoor	Full Outdoor
3	Year Originally Constructed	1974	2002	1983	1950	2002	2003	1980
4	Year Last Unit was Installed	1980	2002	1983	1970	2002	2003	1981
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1,845	715	284	553	603	577	1,026
6	Net Peak Demand on Plant - MW (60 minutes)	1,937	629	845	522	620	594	99
7	Plant Hours Connected to Load	16,578	5,741	1,336	2,002	7,023	6,728	4,845
8	Net Continuous Plant Capability (Megawatts)							
9	When Not Limited by Condenser Water	1,824	580	824	522	511	532	1,646
10	When Limited by Condenser Water	1,824	594	820	522	478	507	1,636
11	Average Number of Employees	1,028	27	49	33	21	16	97
12	Net Generation, Exclusive of Plant Use - kWh	15,191,934,175	2,525,971,567	791,709,484	336,183,528	2,429,030,817	3,209,882,870	2,222,857,627
13	Cost of Plant: Land and Land Rights	2,749,198	1,925,138	499,040	33,725	332,811	2,815,915	1,109,654
14	Structures and Improvements	685,249,100	120,887,824	13,513,350	6,758,667	155,323,935	137,416,992	49,494,827
15	Equipment Costs	3,426,393,186	241,060,824	171,692,586	64,539,226	178,344,817	203,784,189	531,569,553
16	Asset Retirement Costs	222,655,016	0	7,132,609	651,146	0	0	39,638,898
17	Total Cost (10-23)	4,337,046,500	363,873,786	192,837,585	71,982,764	334,001,563	344,017,096	621,812,932
18	Cost per KW of Installed Capacity (line 17/5) Including	2,350.7027	508.9144	679.0056	130.1677	553.8998	596.2168	606.0555
19	Production Expenses: Oper, Supv, & Engr	32,685,575	2,296,942	574,328	1,025,677	1,681,965	884,194	2,633,143
20	Fuel	100,099,779	71,307,505	21,450,237	20,567,086	57,990,121	85,248,967	70,184,070
21	Coolants and Water (Nuclear Plants Only)	8,406,717		0				0

22	Steam Expenses	41,605,418		200,029	1,028,546			2,191,221
23	Steam From Other Sources	0		0				0
24	Steam Transferred (Cr)	0		0				0
25	Electric Expenses	0	798,502	184,361	631,350	1,022,738	1,533,864	467,589
26	Misc Steam (or Nuclear) Power Expenses	42,685,978	2,644,118	58,710	1,800,835	3,240,612	3,241,475	4,494,692
27	Rents	1,024,794	21,083	13,731	22,298	10,594	6,425	17,131
28	Allowances	0		0		14		0
29	Maintenance Supervision and Engineering	16,810,331	465,023	72,556	102,032	212,818	219,385	363,704
30	Maintenance of Structures	1,194	151,179	159,326	260,071	147,526	30,176	1,390,607
31	Maintenance of Boiler (or reactor) Plant	1,537,953		2,580,256	1,497,452			7,068,863
32	Maintenance of Electric Plant	13,558,375	4,345,494	2,607,082	1,213,706	4,417,520	1,246,422	3,461,265
33	Maintenance of Misc Steam (or Nuclear) Plant	77,669,192	215,131	1,373,370	642,322	243,307	162,738	522,584
34	Total Production Expenses	336,085,306	82,244,977	29,273,986	28,791,375	68,967,215	92,573,646	92,794,869
35	Expenses per Net kWh	0.0221	0.0326	0.0370	0.0856	0.0284	0.0288	0.0417

35	Plant Name	Arkansas Nuclear One (Units 1 and 2)	Hot Spring	Independence	Independence	Lake Catherine	Ouachita 1 & 2	Union Power Station	White Bluff	White Bluff
36	Fuel Kind	Nuclear	Gas	Coal	Oil	Gas	Gas	Gas	Coal	Oil
37	Fuel Unit	MWh	Mcf	T	bbl	Mcf	Mcf	Mcf	T	bbl
38	Quantity (Units) of Fuel Burned	46,008,110	18,458,862	466,210	2,623	3,843,440	17,447,783	22,940,482	1,377,261	21,745
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	3,412,600	1,014,821	17,493,542	5,899,984	1,027,615	1,006,182	1,030,775	17,412,898	5,899,998
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000	0.0000
41	Average Cost of Fuel per Unit Burned	2.176	3.863	45.359	115.661	5.351	3.324	3.716	49.158	114.083
42	Average Cost of Fuel Burned per Million BTU	0.638	3.807	2.593	19.604	5.207	3.303	3.605	2.823	19.336
43	Average Cost of Fuel Burned per kWh Net Gen	0.007	0.028	0.027	0.000	0.061	0.054	0.027	0.031	0.000
44	Average BTU per kWh Net Generation	10,334.910	7,415.940	10,320.884		11,748.270	8,003.810	7,366.770	10,846.578	

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: PlantName
Independence - Reflects Entergy Arkansas's 31.5% interest in Independence Unit 1 and its 15.75% interest in Common Plant.
(b) Concept: PlantName
Lake Catherine - Lake Catherine Units 1, 2, and 3 were in retired status for the entire year. Unit 4 is still active.
(c) Concept: PlantName
Ouachita 1 & 2 - Reflects Entergy Arkansas's 100% interest in Ouachita Units 1 and 2 and its 66.7% interest in Common Plant.
(d) Concept: PlantName
Union Power Station - Reflects Entergy Arkansas's 100% ownership in Unit 2 and its 25% ownership in Common facilities.
(e) Concept: PlantName
White Bluff - Reflects Entergy Arkansas's 57% interest in White Bluff Units 1, 2 and Common Plant.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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Renewable Generating Plant Statistics

1. Report data for plant in Service only.
2. Report in this page renewable plants of 10,000 Kw or more.
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. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.

Line No.	Item (a)	Plant Name: 0	Plant Name: Driver	Plant Name: Walnut Bend	Plant Name: West Memphis
1	Kind of Plant (Solar, Wind, Biomass, etc.)		Solar	Solar	Solar
2	Type of Constr (PV Tracking, Offshore, Boiler, etc)				
3	Year Originally Constructed		2024	2024	2024
4	Year Last Unit was Installed		2024	2024	2024
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		150	100	252
6	Net Peak Demand on Plant - MW (60 minutes)		250	100	181
7	Plant Hours Connected to Load		4,405	4,456	4,249
8	Net Continuous Plant Capability (Megawatts)				
9	Net Generation, Exclusive of Plant Use - KWh		499,056,516	219,255,532	361,436,814
10	Cost of Plant: Land and Land Rights		1,632,865	200,245	22,843,489
11	Structures and Improvements		43,551,389	15,469,899	12,370,302
12	Solar Panels, Wind Turbines and Generators		260,374,529	148,334,384	169,024,631
13	Fuel Holders				
14	Boilers				
15	Collector System		32,817,849	11,915,352	15,456,319
16	Generator Step-up Transformers (GSU)		3,880,639	1,921,874	1,695,271
17	Inverters		15,854,536	8,406,231	6,781,087
18	Other Accessory Electrical Equipment		30,552,949	7,470,415	11,015,512
19	Computer Hardware		2,577,913	1,115,043	1,317,081
20	Computer Software				
21	Communication Equipment		30,694	13,802	30,706
22	Miscellaneous Power Plant Equipment		1,094,323	1,332,062	164,154
23	Asset Retirement Costs		13,198,070	4,524,566	
24	Total Cost (10-23)		405,565,756	200,703,873	240,698,552
25	Cost per KW of Installed Capacity (line 24/5) Including				
26	Production Expenses: Oper, Supv, & Engr		54,628	23,419	45,635
27	Generation and Other Plant Operating Expenses		67,343	359,937	22,442
28	Fuel				

29	Steam Expenses				
30	Electric Expenses				
31	Misc Steam Power Expenses				
32	Rents		2,440,046		
33	Environmental Credits				
34	Maintenance Supervision and Engineering				
35	Maintenance of Structures and Equipment		2,029,843	1,450,578	2,222,349
36	Maintenance of Boiler Plant				
37	Maintenance of Electric Plant				
38	Maintenance of Computer Hardware				
39	Maintenance of Computer Software				
40	Maintenance of Communication Equipment				
41	Maintenance of Misc Plant				
42	Total Production Expenses		4,591,860	1,833,934	2,290,426
43	Expenses per Net KWh		0.0092	0.0084	0.0063

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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Hydroelectric Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Carpenter	FERC Licensed Project No. 0 Plant Name: Rommel
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1932	1923
4	Year Last Unit was Installed	1933	1923
5	Total installed cap (Gen name plate Rating in MW)	56.00	9.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	82	12
7	Plant Hours Connect to Load	4,712	6,658
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	62	12
10	(b) Under the Most Adverse Oper Conditions	62	12
11	Average Number of Employees	3	
12	Net Generation, Exclusive of Plant Use - kWh	147,544,481	46,134,699
13	Cost of Plant		
14	Land and Land Rights	1,060,395	244,021
15	Structures and Improvements	2,276,884	1,657,859
16	Reservoirs, Dams, and Waterways	6,056,234	10,544,285
17	Equipment Costs	18,598,805	13,632,141
18	Roads, Railroads, and Bridges		
19	Asset Retirement Costs	6,187	1,154
20	Total Cost (10-23)	27,998,505	26,079,460
21	Cost per KW of Installed Capacity (line 20 / 5)	499.9733	2,897.7178
22	Production Expenses		
23	Operation Supervision and Engineering	192,826	15,100
24	Water for Power	334,104	48,911
25	Hydraulic Expenses		
26	Electric Expenses	2,104	(1,544)

27	Misc Hydraulic Power Generation Expenses	296,579	119,965
28	Rents		
29	Maintenance Supervision and Engineering	65	
30	Maintenance of Structures	40,417	18,790
31	Maintenance of Reservoirs, Dams, and Waterways	1,029,710	610,492
32	Maintenance of Electric Plant	222,545	219,493
33	Maintenance of Misc Hydraulic Plant	468,784	37,394
34	Total Production Expenses (total 23 thru 33)	2,587,134	1,068,601
35	Expenses per net kWh	0.0175	0.0232

Name of Respondent: Energy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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Pumped Storage Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand 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 (10-23)	
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)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per kWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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35	TOTAL		0	0	0	0	0	0	0	0	0	0

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33								
34								
35								
36	TOTAL		0	0	0	0	0	0

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION LINE STATISTICS

- 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.
- 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.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- 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.
- 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.
- 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).
- 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.
- 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.
- Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	ARKANSAS NUCLEAR	FT SMITH 500 - [6001,6006]	500	500	Steel Tower	46.78	0.00	1	954 ACSR							
2	ARKANSAS NUCLEAR	MABELVALE 500 - [6001,6006]	500	500	Steel Tower	86.68	0.00	1	954 ACSR							
3	ARKANSAS NUCLEAR	PLEASANT HILL 500 - [6002]	500	500	Steel Tower	32.53	0.00	1	954 ACSR							
4	DELL	POWERLINE 500 - [6015]	500	500	Steel Tower	36.73	0.00	1	954 ACSR							
5	DELL	SAN SOUCI 500 - [40867]	500	500	Steel Tower	19.04	0.00	1	954 ACSR							
6	DRIVER	SANDY BAYOU 500 kV - [40875]	500	500	Steel Tower	3.15	0.00	1	[3]-954 ACSR							
7	EL DORADO	MT OLIVE 500 - [6003]	500	500	Steel Tower	20.04	0.00	1	1024.5 ACAR							
8	ELDORADO	UNION POWER 500 LN 1 - [1609]	500	500	Steel Tower	0.26	0.00	1	954 ACSR							
9	ELDORADO	UNION POWER 500 LN 2 - [1609]	500	500	Steel Tower	0.31	0.00	1	954 ACSR							
10	ETTA	HOT SPRINGS 500 - [6014]	500	500	Steel Tower	9.88	0.00	1	954 ACSR							
11	HOT SPRINGS	MAGNET COVE 500 - [6017]	500	500	Steel Tower	2.69	0.00	1	954 ACSR							
12	INDEPENDENCE	HOLLAND BOTTOM 500 - [6016]	500	500	Steel Tower	64.26	0.00	1	954 ACSR							
13	INDEPENDENCE	POWERLINE 500 - [6015]	500	500	Steel Tower	46.38	0.00	1	954 ACSR							

14	KEO	HOLLAND BOTTOM 500 - [6016]	500	500	Steel Tower	22.21	0.00	1	954 ACSR								
15	KEO	WEST MEMPHIS 500 - [40854]	500	500	Steel Tower	111.44	0.00	1	954 ACSR								
16	KEO	WHITE BLUFF 500 - [6010]	500	500	Steel Tower	17.25	0.00	1	954 ACSR								
17	MABELVALE	MAYFLOWER 500 - [6007]	500	500	Steel Tower	18.87	11.05	2	954 ACSR								
18	MABELVALE	SHERIDAN 500 - [6005]	500	500	Steel Tower	19.87	0.00	1	954 ACSR								
19	MABELVALE	WRIGHTSVILLE 500 - [40847]	500	500	Steel Tower	14.57	0.00	1	954 ACSR								
20	MAYFLOWER	PLEASANT HILL 500 - [6002]	500	500	Aluminum Tower	28.32	0.00	1	954 ACSR								
21	MCNEIL	ELDORADO 500 - [6013]	500	500	Steel Tower	37.86	0.00	1	954 ACSR								
22	MCNEIL	ETTA 500 - [6014]	500	500	Steel Tower	74.46	0.00	1	954 ACSR								
23	NEW MADRID	DELL 500 - [6012]	500	500	Steel Tower	9.61	0.00	1	954 ACSR								
24	OUACHITA (COGENTRIX)	STERLINGTON 500 - [2019]	500	500	Various	0.21	0.00	1	954 ACSR								
25	SAN SOUCI	DRIVER 500 - [40868]	500	500	Steel H-Frame	0.52	0.00	1	954 ACSR								
26	SANDY BAYOU	SHELBY 500 kV - [40878]	500	500	Steel Tower	6.08	0.00	1	[3]-954 ACSR								
27	SHERIDAN	ELDORADO 500 - [6005]	500	500	Steel Tower	75.66	0.00	1	954 ACSR								
28	SHERIDAN	MAGNET COVE 500 - [6017]	500	500	Steel Tower	24.17	0.00	1	954 ACSR								
29	STERLINGTON	EL DORADO 500 - [40850]	500	500	Steel Tower	24.48	0.00	1	954 ACSR								
30	W MEMPHIS	FREEPORT 500 - [6018]	500	500	Steel Tower	1.49	0.00	1	954 ACSR								
31	WHITE BLUFF	SHERIDAN 500 - [6011]	500	500	Steel Tower	18.63	0.00	1	954 ACSR								
32	WRIGHTSVILLE	KEO 500 - [40848]	500	500	Steel Tower	10.65	0.00	1	954 ACSR								
33	Total 500kV									25,366,574	295,849,669	321,216,243					
34	ELDORADO 500	SAREPTA 345 - [6101]	345	345	Aluminum Tower	43.78	0.00	1	1024.5 ACAR								
35	Total 345kV									349,202	3,313,371	3,662,573					
36	BRINKLEY EAST	FLAT FORK 230 - [42876]	230	230	Wood H-Frame	2.95	0.00	1	1534.4 ACAR								
37	DRIVER	BIG RIVER STEEL 230 LN 1 - [6207]	230	230	Steel Pole	2.22	0.00	1	1590 ACSR								
38	DRIVER	BIG RIVER STEEL 230 LN 2 - [6208]	230	230	Steel Pole	2.19	0.00	1	1590 ACSR								
39	DRIVER	DRVRSOL ZBR 230 - [42877]	230	230	Steel Pole	0.25	0.00	1	1272 ACSR								
40	DRIVER	HYBAR 230 - [42887]	230	230	Steel Pole	2.61	0.00	1	1272 ACSR								
41	FLAT FORK	RITCHIE 230 - [42870]	230	230	Wood H-Frame	41.99	0.00	1	1534.4 ACAR								

42	GERALD ANDRUS	LAKE VILLAGE BAGBY 230 - [6201]	230	230	Wood H- Frame	14.20	0.00	1	1534.4 ACAR								
43	RITCHE	LONG LAKE SOLAR 230 KV - [42879]	230	230	Steel Pole	0.43	0.00	1	666.6 ACSR								
44	RITCHIE	MOON LAKE 230 - [6203]	230	230	Steel Tower	1.09	0.00	1	1947.5 ACSR								
45	RITCHIE	TARLETON 230 - [6204]	230	230	Steel Tower	35.98	0.00	1	1272 ACSR								
46	RITCHIE	TUNICA 230 - [6206]	230	230	Steel Tower	0.92	0.00	1	1947.5 ACSR								
47	STUTT GART RICUSKEY	TARLETON 230 - [6204,6205]	230	230	Steel Tower	21.09	7.44	2	1272 ACSR								
48	STUTT GART	WOODWARD 230 - [6204,6205]	230	230	Steel Tower	35.15	7.56	2	1272 ACSR								
49	WOODWARD	WHITE BLUFF 230 - [6209]	230	230	Steel Pole	23.00	0.00	1	954 ACSS								
50	Total 230kv									5,401,780	79,359,902	84,761,682					
51	AECC HYDRO 9	OPPELO 161 - [6321]	161	161	Wood H- Frame	3.77	0.00	1	666.6 ACSR								
52	ARKANSAS NUCLEAR	PLEASANT HILL 161 - [6301]	161	161	Wood H- Frame	32.29	1.72	2	1024.5 ACAR								
53	ARKANSAS NUCLEAR	RUSSELVILLE E 161 - [6302]	161	161	Wood H- Frame	10.23	1.72	2	1272 ACSS								
54	BAILEY	MOSES 161 - [6324,6325]	161	161	Wood H- Frame	38.34	0.00	1	336.4 ACSR								
55	BLYTHEVILLE ELM ST	BLYTHEVILLE I 55 161 - [43701]	161	161	Concrete Pole	1.39	1.97	2	1272 ACSR								
56	BLYTHEVILLE ELM ST	CROOKED LAKE 161 - [6373]	161	161	Concrete Pole	7.49	1.95	2	954 ACSR								
57	BLYTHEVILLE ELM	DELL 161 - [6341,6366]	161	161	Steel Tower	3.99	4.84	2	1272 ACSR								
58	BLYTHEVILLE ELM	DELL 161 - [43703]	161	161	Wood H- Frame	7.89	0.00	1	1272 ACSR								
59	BLYTHEVILLE I	FLAT LAKE 161 kV - [43709]	161	161	Concrete Pole	0.89	0.00	1	1590 ACSR								
60	BLYTHEVILLE N	STEELE 161 - [43701,6350]	161	161	Concrete Pole	9.81	0.00	1	1590 ACSR								
61	BOB WHITE	EBONY 161 - [43923]	161	161	Wood H- Frame	12.87	0.00	1	666.6 ACSR								
62	BOB WHITE	MARKED TREE 161 - [43631]	161	161	Wood H- Frame	13.07	0.00	1	666.6 ACSR								
63	BULL SHOALS	HARRISON EAST 161 - [6335,6370]	161	161	Steel Pole	34.08	0.00	1	250 24R1 HOLLOW CU								
64	BULL SHOALS	NORFORK 161 - [6335]	161	161	Steel Pole	24.67	0.00	1	1272 ACSR								
65	COFER RD	SOUTHSIDE 161 - [6316]	161	161	Wood H- Frame	37.28	0.00	1	666.6 ACSR								
66	CONWAY WEST	MORRILTON EAST 161 - [6307]	161	161	Wood H- Frame	15.28	0.00	1	666.6 ACSR								

67	CORNING	BALTZ 161 - [6362,6696]	161	161	Wood H-Frame	27.48	0.00	1	1590 ACSR								
68	DANVILLE	MAGAZINE 161 - [6309]	161	161	Various	0.03	0.00	1	1272 ACSR								
69	DARDANELLE DAM	DANVILLE 161 - [6308]	161	161	Wood H-Frame	19.23	0.00	1	666.6 ACSR								
70	DELL	PARAGOULD 161 - [43703,6345]	161	161	Wood H-Frame	32.31	0.00	1	666.6 ACSR								
71	DELL	OSCEOLA 161 - [6336,6341,6366]	161	161	Wood H-Frame	15.60	4.92	2	1590 ACSR								
72	DRY CREEK	HARRISON EAST 161 - [6314]	161	161	Wood H-Frame	26.21	0.00	1	666.6 ACSR								
73	EBONY	WEST MEMPHIS EHV 161 LN 1 - [43633]	161	161	Wood H-Frame	6.45	0.00	1	666.6 ACSR								
74	EBONY	WEST MEMPHIS EHV 161 LN 2 - [6338]	161	161	Wood Pole	8.78	0.00	1	666.6 ACSR								
75	EBONY	GATEWAY 161 - [6339]	161	161	Wood H-Frame	6.15	0.00	1	336.4 ACSR								
76	FALLS	HAMRICK 161 - [43641]	161	161	Steel Pole	1.11	0.00	1	336.4 ACSR								
77	FLAT LAKE	BLYTHEVILLE NORTH 161 kV - [43708]	161	161	Concrete Pole	2.31	0.00	1	1590 ACSR								
78	GAINSVILLE	PARAGOULD 161 - [6346]	161	161	Concrete Pole	8.47	0.00	1	1272 ACSR								
79	HAMLET	CONWAY WEST 161 - [6306]	161	161	Wood H-Frame	11.28	3.16	2	666.6 ACSR								
80	HAMLET	SYLVAN HILLS 161 - [6312]	161	161	Wood H-Frame	12.58	6.99	2	666.6 ACSR								
81	HAMLET	HOLLAND BOTTOM 161 - [0819]	161	161	Steel Pole	21.36	0.00	1	666.6 ACSS								
82	HAMRICK	MOSES 161 - [43960]	161	161	Wood H-Frame	17.05	0.00	1	336.4 ACSR								
83	HARRISON EAST	HILLTOP 161 - [6313]	161	161	Wood H-Frame	26.47	0.00	1	666.6 ACSR								
84	HARRISON EAST	OZARK BEACH 161 - [6335]	161	161	Wood Pole	32.03	0.00	1	250 24R1 HOLLOW CU								
85	HAYTI SOUTH	HAYTI NORTH 161 - [6351]	161	161	Various	0.05	0.00	1	336.4 ACSR								
86	HAYTI SOUTH	MARSTON 161 - [6352]	161	161	Wood H-Frame	23.85	0.00	1	1272 ACSR								
87	HAYTI SOUTH	STEELE 161 - [6350]	161	161	Concrete Pole	8.25	0.00	1	1590 ACSR								
88	HEBER SPRINGS NORTH	GREERS FERRY 161 - [42635]	161	161	Wood H-Frame	1.59	0.00	1	666.6 ACSR								
89	HEBER SPRINGS NORTH	QUITMAN 161 - [42903]	161	161	Wood H-Frame	19.07	0.00	1	336.4 ACSR								
90	HILLTOP	CLINTON WEST 161 - [6313]	161	161	Wood H-Frame	30.14	0.00	1	666.6 ACSR								
91	INDEPENDENCE	SEARCY PRICE 161 - [6315,6361,6652]	161	161	Wood H-Frame	35.67	7.91	2	1590 ACSR								

92	INDEPENDENCE	SAGE 161 - [6303,6331,6369]	161	161	Steel Pole	36.78	7.62	2	954 ACSR								
93	INDEPENDENCE	RUTHERFORD 161 - [6316]	161	161	Steel Tower	0.98	6.35	2	1590 ACSR								
94	JIM HILL	GAINESVILLE 161 - [6346,6347,6353]	161	161	Concrete Pole	28.64	0.00	1	1272 ACSR								
95	JIM HILL	CORNING 161 - [6696,6700,6701]	161	161	Steel Pole	29.67	0.00	1	1272 ACSR								
96	JIM HILL	HAYTI SOUTH 161 - [6351]	161	161	Concrete Pole	26.73	0.00	1	666.6 ACSR								
97	JONESBORO	LOCUST CREEK 161 - [6333]	161	161	Concrete H-Frame	28.28	0.00	1	1272 ACSR								
98	JONESBORO(EAI)	JONESBORO(SPA) 161 - [6320]	161	161	Wood H-Frame	0.84	0.00	1	1272 ACSS								
99	KUHN RD	EBONY 161 - [0811]	161	161	Steel Pole	2.45	0.00	1	666.6 ACSR								
100	KUHN ROAD	WEST MEMPHIS SOLAR 161 - [43799]	161	161	Steel Pole	3.97	0.00	1	666.6 ACSR								
101	LOCUST CREEK	MALLORY 161 - [6333]	161	161	Concrete H-Frame	4.45	0.00	1	1272 ACSR								
102	MALLORY	NEWPORT 161 - [6330]	161	161	Concrete Pole	5.14	0.00	1	1272 ACSS								
103	MALLORY	NEWPORT INDUSTRIAL 161 - [6333]	161	161	Wood H-Frame	4.88	0.00	1	1590 ACSR								
104	MARKED TREE	LEPANTO 161 - [6322]	161	161	Wood H-Frame	9.03	0.00	1	666.6 ACSR								
105	MORRILTON EAST	PLEASANT HILL 161 - [6301]	161	161	Concrete Pole	5.34	0.00	1	1024.5 ACAR								
106	MORRILTON WEST	AECC HYDRO 9 161 - [6321]	161	161	Wood Pole	7.76	0.00	1	666.6 ACSR								
107	MOSES	W MEMPHIS 161 - [6329]	161	161	Wood H-Frame	43.20	0.00	1	336.4 ACSR								
108	MOSES	BRINKLEY EAST 161 - [6305]	161	161	Wood H-Frame	16.59	0.00	1	954 ACSR								
109	NEW MADRID	MARSTON 161 - [6352]	161	161	Steel Tower	4.08	0.00	1	1272 ACSR								
110	NEWPORT	INDEPENDENCE 161 LN 1 - [6315,6361]	161	161	Steel Tower	2.48	7.91	2	1590 ACSR								
111	NEWPORT	INDEPENDENCE 161 LN 2 - [6331]	161	161	Wood H-Frame	11.81	0.00	1	1590 ACSR								
112	NEWPORT	INDEPENDENCE 161 LN 3 - [6716]	161	161	Concrete Pole	11.30	0.00	1	1590 ACSR								
113	NEWPORT	PRAIRIE CREEK 161 - [43963]	161	161	Wood H-Frame	34.26	0.00	1	666.6 ACSR								
114	NEWPORT	BAILEY 161 - [6324,6325]	161	161	Wood H-Frame	31.64	0.00	1	336.4 ACSR								
115	NUCOR YAMAMOTO	CROOKED LAKE 161 - [6358]	161	161	Concrete Pole	0.59	0.00	1	954 ACSR								
116	OSAGE	DRY CREEK 161 - [6314]	161	161	Wood H-Frame	14.24	0.00	1	666.6 ACSR								

117	OSAGE CREEK	EUREKA 161 - [0899.2]	161	161	Wood Pole	1.18	0.00	1	666.6 ACSR								
118	OSAGE CREEK	GRANDVIEW 161 - [0874]	161	161	Various	5.23	0.00	1	666.6 ACSS								
119	OSCEOLA	WILSON 161 - [6337]	161	161	Wood H- Frame	7.21	0.00	1	336.4 ACSR								
120	PARAGOULD	JONESBORO 161 - [6333,6346]	161	161	Concrete Pole	20.95	0.00	1	666.6 ACSR								
121	PARKIN	WILSON 161 - [6337]	161	161	Wood H- Frame	35.78	0.00	1	336.4 ACSR								
122	PARKIN	KUHN RD 161 - [6338]	161	161	Wood H- Frame	18.69	0.00	1	666.6 ACSR								
123	PARKIN	MARKED TREE 161 - [6317]	161	161	Wood H- Frame	18.89	0.00	1	397.5 ACSR								
124	PARKIN	FALLS 161 - [43632]	161	161	Wood H- Frame	14.86	0.00	1	336.4 ACSR								
125	PARKIN	MOSES 161 - [6327,6328]	161	161	Wood H- Frame	6.51	0.00	1	336.4 ACSR								
126	PINNACLE	OPPELLO 161 - [6321]	161	161	Wood H- Frame	29.11	0.00	1	666.6 ACSR								
127	POWER LINE	HERGETT 161 LN 2 - [6319]	161	161	Wood H- Frame	0.33	3.03	2	1534.4 ACAR								
128	POWER LINE	HERGETT 161 LN1 - [6319]	161	161	Wood H- Frame	0.31	3.04	2	1534.4 ACAR								
129	POWER LINE	JONSBORO 161 - [6317]	161	161	Steel Pole	10.50	1.26	2	1534.4 ACAR								
130	POWER LINE	MARKED TREE 161 - [6317,6318]	161	161	Concrete Pole	41.17	1.36	2	666.6 ACSR								
131	PRAIRIE CREEK	PARKIN 161 KV - [43617]	161	161	Wood H- Frame	14.67	0.00	1	666.6 ACSR								
132	QUITMAN	CLINTON WEST 161 - [6313]	161	161	Wood H- Frame	23.76	0.00	1	666.6 ACSR								
133	QUITMAN	PLEASANT HILL 161 - [42820,6371]	161	161	Concrete Pole	32.51	0.00	1	954 ACSR								
134	QUITMAN	HAMLET 161 - [42634]	161	161	Wood H- Frame	14.57	0.00	1	666.6 ACSR								
135	RUSSELLVILLE EAST	MORRILTON E 161 - [6323]	161	161	Wood H- Frame	25.20	0.00	1	1534.4 ACAR								
136	RUSSELVILLE EAST	DARDENELLE DAM 161 - [6308]	161	161	Steel Pole	7.11	0.00	1	954 ACSS								
137	RUTHERFORD	SOUTHSIDE 161 - [6316]	161	161	Wood H- Frame	9.36	0.00	1	666.6 ACSR								
138	SAGE	NORFORK 161 - [6303,6304]	161	161	Wood Pole	50.45	0.00	1	1272 ACSR								
139	SEARCY PRICE	COFER RD 161 - [6316]	161	161	Wood H- Frame	15.94	2.46	2	666.6 ACSR								
140	SEARCY PRICE	SERACY SOLAR 161 - [6359]	161	161	Steel H- Frame	0.11	0.00	1	1272 ACSR								
141	THAYER S	WALNUT RIDGE 161 - [6367,6368]	161	161	Wood H- Frame	49.26	0.00	1	666.6 ACSR								

142	WALNUT RIDGE	MALLORY 161 - [6330,6348]	161	161	Wood H- Frame	32.39	0.00	1	636 ACSR							
143	WATER VALLEY	BALTZ LAKE 161 - [6365]	161	161	Wood Pole	6.08	0.00	1	1590 ACSR							
144	Total 161kV									18,141,825	404,773,231	422,915,056				
145	Total Other					2,090.60	151.19			30,900,336	502,497,711	533,398,047	15,610,725	8,363,529	5,471	23,979,725
36	TOTAL					4,707.65	245.45	160		80,159,717	1,285,793,884	1,365,953,601	15,610,725	8,363,529	5,471	23,979,725

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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 completed 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 (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Construction (q)
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
	1	DRIVER		HYBAR 230 - [42887]	2.61	Steel Pole	10.00	1	1	1272		ACSR	230	230	1,246,834	2,835,283	
2	KUHN ROAD	WEST MEMPHIS SOLAR 161 - [43799]	3.97	Steel Pole	9	1	1	666.6	ACSR	161	161	407,082	80,320	179,284		666,686	
3	LYNCH	WRIGHTSVILLE 115 - [45828]	1.54	Steel Pole	12	2	2	1590	ACSR	115	115	74,719	395,521	292,259		762,499	
44	TOTAL		8.12		31	4	4					1,728,635	3,311,124	1,489,441		6,529,200	

Name of Respondent: Energy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- 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.
- 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).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVA)			Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
1	ALCOA ROAD	Distribution	Unattended	115.0	14.4		67	2	0			
2	ALMYRA	Distribution	Unattended	115.0	13.8		10	1	0			
3	ALTHEIMER	Distribution	Unattended	115.0	13.9		13	1	0			
4	AMITY	Distribution	Unattended	115.0	13.9		20	1	0			
5	ANTOINE	Distribution	Unattended	34.0								
6	ARKADELPHIA NORTH	Distribution	Unattended	115.0	13.8		33	1	0			
7	ARKADELPHIA WEST	Distribution	Unattended	115.0	13.9		30	1	0			
8	ARKLAHOMA	Distribution	Unattended	115.0	13.9		20	1	0			
9	ARMOREL	Distribution	Unattended	34.0	12.5		18	2	0			
10	ATKINS	Distribution	Unattended	161.0	13.9		40	2	0			
11	BALD KNOB	Distribution	Unattended	161.0	13.9		67	2	0			
12	BARTON	Distribution	Unattended	115.0	13.9		7	1	0			
13	BATESVILLE [AR]	Distribution	Unattended	161.0	13.9		93	3	0			
14	BAUCUM	Distribution	Unattended	115.0	13.9		13	1	0			
15	BAUXITE	Distribution	Unattended	115.0	13.9		25	1	0			
16	BEARDEN	Distribution	Unattended	115.0	13.9		13	1	0			
17	BEEBE	Distribution	Unattended	115.0	13.9		67	2	0			
18	BEIRNE	Distribution	Unattended	115.0	13.8		17	1	0			
19	BENTON NORTH	Distribution	Unattended	115.0	13.9		34	1	0			
20	BENTON SOUTH	Distribution	Unattended	115.0	13.8		33	1	0			
21	BERRYVILLE	Distribution	Unattended	161.0	13.9		53	2	0			
22	BIG CREEK	Distribution	Unattended	115.0	13.8		40	1	0			
23	BIGGERS	Distribution	Unattended	34.0	4.0		1	1	1			

24	BISMARCK	Distribution	Unattended	115.0	13.9		46	2	0			
25	BLACK OAK	Distribution	Unattended	34.0	12.5		5	1	0			
26	BLACK ROCK	Distribution	Unattended	34.0	12.4		3	1	0			
27	BLYTHEVILLE AFB	Distribution	Unattended	34.0	12.5		30	3	0			
28	BLYTHEVILLE ELM ST	Distribution	Unattended	161.0	34.5		75	2	1			
29	BLYTHEVILLE FLAT LAKE	Distribution	Unattended	34.0	12.5		0	0	1			
30	BLYTHEVILLE I-55	Distribution	Unattended	161.0	34.5		75	2	0			
31	BLYTHEVILLE N.EAST	Distribution	Unattended	34.0	12.5		18	2	0			
32	BLYTHEVILLE N.WEST	Distribution	Unattended	34.0	12.5		16	2	0			
33	BLYTHEVILLE PLANT 34.5KV	Distribution	Unattended	34.0	4.2		11	1	0			
34	BLYTHEVILLE S.EAST	Distribution	Unattended	34.0	12.5		11	1	0			
35	BLYTHEVILLE S.WEST	Distribution	Unattended	34.0	12.5		11	1	0			
36	BONO	Distribution	Unattended	161.0	13.8		40	1	0			
37	BRINKLEY EAST	Distribution	Unattended	230.0	13.9		26	2	0			
38	BRINKLEY WEST	Distribution	Unattended	115.0	13.8		33	1	0			
39	BRYANT	Distribution	Unattended	115.0	13.9		84	2	0			
40	BULL SHOALS	Distribution	Unattended	161.0	13.9		20	1	0			
41	BUTLER HALL	Distribution	Unattended	34.0	12.4		4	1	0			
42	BUTTERFIELD	Distribution	Unattended	115.0	13.9		13	1	0			
43	CABOT [AR]	Distribution	Unattended	115.0	14.5		53	2	0			
44	CALICO ROCK	Distribution	Unattended	161.0	13.9		10	1	0			
45	CAMDEN MAGUIRE	Distribution	Unattended	115.0	13.9		20	1	0			
46	CAMDEN NORTH	Distribution	Unattended	115.0	13.9		67	2	0			
47	CARLISLE [AR]	Distribution	Unattended	115.0	13.8		20	1	0			
48	CARPENTER DAM	Distribution	Unattended	115.0	13.9		33	1	0			
49	CARTHAGE (AR)	Distribution	Unattended	115.0	13.9		13	1	0			
50	CASH	Distribution	Unattended	161.0	13.8		22	1	0			
51	CAVE CITY	Distribution	Unattended	161.0	34.5		54	2	0			
52	CEDAR GROVE	Distribution	Unattended	161.0	13.9		20	1	0			
53	CHAMPS	Distribution	Unattended	115.0	13.8		40	1	0			
54	CHERRY VALLEY	Distribution	Unattended	161.0	13.9		20	1	0			
55	CLARENDON	Distribution	Unattended	115.0	13.9		13	1	0			
56	COFER ROAD	Distribution	Unattended	161.0	13.8		40	1	0			
57	COLLEGE CITY	Distribution	Unattended	34.0	12.5		11	1	0			
58	CORNING 161 SUB	Distribution	Unattended	161.0	34.5		37	1	0			
59	CORNING 34.5	Distribution	Unattended	34.0	12.5		15	2	0			
60	COTTON PLANT	Distribution	Unattended	115.0	13.9		7	1	0			

61	COUCH SWYD	Distribution	Unattended	115.0	13.8		20	1	0			
62	CROOKED LAKE	Distribution	Unattended	161.0	34.5		33	1	0			
63	CROSSETT NORTH	Distribution	Unattended	115.0	13.9		67	2	0			
64	CROSSETT WEST	Distribution	Unattended	115.0	13.9		34	1	0			
65	CUSHMAN	Distribution	Unattended	161.0	13.8		7	1	0			
66	DALARK	Distribution	Unattended	115.0	34.5		20	1	0			
67	DANVILLE [AR]	Distribution	Unattended	161.0	13.9		45	2	0			
68	DARDANELLE	Distribution	Unattended	161.0	13.8		67	2	0			
69	DATTO	Distribution	Unattended	161.0	34.5		20	1	0			
70	DELIGHT	Distribution	Unattended	34.0	13.8		6	1	0			
71	DELL CITY	Distribution	Unattended	34.0	12.5		2	1	0			
72	DERMOTT	Distribution	Unattended	115.0	13.8		20	1	0			
73	DES ARC	Distribution	Unattended	115.0	13.8		33	1	0			
74	DEVALLS BLUFF	Distribution	Unattended	115.0	13.8		7	1	0			
75	DEWITT	Distribution	Unattended	115.0	13.9		58	2	0			
76	DIAMOND CITY	Distribution	Unattended	34.0	19.9		5	1	0			
77	DRIVER	Distribution	Unattended	500.0	13.8		122	4	1			
78	DUMAS	Distribution	Unattended	115.0	13.8		67	2	0			
79	EL DORADO DONAN	Distribution	Unattended	115.0	13.9		63	2	0			
80	EL DORADO EAST	Distribution	Unattended	115.0	13.8		50	2	0			
81	EL DORADO JACKSON	Distribution	Unattended	115.0	14.4		63	2	0			
82	EL DORADO MILL ROAD	Distribution	Unattended	115.0	13.8		20	1	0			
83	EL DORADO NEWELL	Distribution	Unattended	115.0	115.0		20	1	0			
84	EL DORADO PARKERS CHAPEL	Distribution	Unattended	115.0	13.9		20	1	0			
85	EL DORADO PARNELL ROAD	Distribution	Unattended	115.0	14.4		50	1	0			
86	EL DORADO QUINN	Distribution	Unattended	115.0	13.9		13	1	0			
87	EL DORADO UPLAND	Distribution	Unattended	115.0	13.9		53	2	0			
88	EL DORADO WEST	Distribution	Unattended	115.0	14.4		34	1	0			
89	ELAINE	Distribution	Unattended	115.0	13.8		13	1	0			
90	EMERSON	Distribution	Unattended	115.0	13.9		13	1	0			
91	ENGLAND	Distribution	Unattended	115.0	13.9		25	2	0			
92	EUDORA	Distribution	Unattended	115.0	34.5		20	1	0			
93	EVERTON ROAD	Distribution	Unattended	161.0	13.8	33.0	25	1	0			
94	FAULKNER LAKE	Distribution	Unattended	115.0	14.4		67	1	0			
95	FISHER	Distribution	Unattended	161.0	13.9		53	2	0			
96	FLIPPIN	Distribution	Unattended	161.0	13.9		60	2	0			
97	FORDYCE	Distribution	Unattended	115.0	13.9		30	2	0			

98	FORREST CITY NORTH	Distribution	Unattended	161.0	13.9		42	2	0			
99	FORREST CITY SOUTH	Distribution	Unattended	161.0	13.9		22	1	0			
100	FOUNTAIN LAKE	Distribution	Unattended	115.0	13.8		33	1	0			
101	FRAZIER PIKE	Distribution	Unattended	115.0	13.8		50	1	1			
102	FRIENDSHIP	Distribution	Unattended	115.0	13.8		6	1	0			
103	GIFFORD	Distribution	Unattended	115.0	14.4		61	2	0			
104	GILLETT	Distribution	Unattended	115.0	13.9		13	1	0			
105	GILMORE	Distribution	Unattended	161.0	13.8		11	1	0			
106	GLEASON	Distribution	Unattended	161.0	13.9		42	2	0			
107	GLENWOOD	Distribution	Unattended	115.0	13.9		22	1	0			
108	GRAND PRAIRIE	Distribution	Unattended	115.0	4.2		67	2	0			
109	GREEN FOREST	Distribution	Unattended	161.0	13.9		20	1	0			
110	GREEN FOREST SOUTH	Distribution	Unattended	161.0	13.9		70	2	0			
111	GREENBRIER	Distribution	Unattended	161.0	161.0		83	2	0			
112	GREENWAY	Distribution	Unattended	34.0	4.2		1	1	0			
113	GREYHAWK	Distribution	Unattended	161.0	13.8		40	1	0			
114	GRIFFITHVILLE	Distribution	Unattended	115.0	13.8		20	1	0			
115	GUION	Distribution	Unattended	161.0	13.8		7	1	0			
116	GURDON	Distribution	Unattended	115.0	33.0	13.9	23	2	0			
117	H.S. ALBRIGHT	Distribution	Unattended	115.0	13.8		50	1	0			
118	H.S. EAST	Distribution	Unattended	115.0	13.8		5	1	0			
119	H.S. INDUSTRIAL SUB	Distribution	Unattended	115.0	13.9		13	1	0			
120	H.S. MILTON	Distribution	Unattended	115.0	13.9		67	2	0			
121	H.S. MT. VALLEY	Distribution	Unattended	115.0	13.8		33	1	0			
122	H.S. NORTH	Distribution	Unattended	115.0	13.9		30	1	0			
123	H.S. ROYAL	Distribution	Unattended	115.0	13.9		33	1	0			
124	H.S. SOUTH	Distribution	Unattended	115.0	14.4		67	2	0			
125	H.S. UNION CARBIDE	Distribution	Unattended	115.0	13.8		20	1	0			
126	H.S. VALLEY STREET	Distribution	Unattended	115.0	13.9		64	2	0			
127	H.S. VILLAGE	Distribution	Unattended	115.0	13.9		54	2	0			
128	H.S. WEST	Distribution	Unattended	115.0	13.9		34	1	0			
129	HAMBURG	Distribution	Unattended	115.0	13.8		20	1	0			
130	HAMLET SUB	Distribution	Unattended	161.0	13.8		64	2	0			
131	HARDIN WEST	Distribution	Unattended	115.0	13.8		7	1	0			
132	HARDY NORTH	Distribution	Unattended	161.0	13.2		33	1	0			
133	HARRISBURG	Distribution	Unattended	161.0	13.9		60	2	0			
134	HARRISON EAST	Distribution	Unattended	161.0	13.9		63	2	0			

135	HARRISON WEST	Distribution	Unattended	161.0	13.9		100	3	0			
136	HASKELL	Distribution	Unattended	115.0	13.9		40	2	0			
137	HAYS CITY	Distribution	Unattended	115.0	13.9		20	1	0			
138	HAZEN	Distribution	Unattended	115.0	13.8		40	1	0			
139	HEBER SPRINGS INDUSTRIAL	Distribution	Unattended	161.0	13.8		33	1	0			
140	HEBER SPRINGS SOUTH	Distribution	Unattended	161.0	13.8		34	1	0			
141	HELENA CENTRAL	Distribution	Unattended	115.0	13.9		20	1	0			
142	HELENA SOUTH	Distribution	Unattended	115.0	13.9		20	1	0			
143	HENSLEY	Distribution	Unattended	115.0	13.8		13	1	0			
144	HERMITAGE	Distribution	Unattended	115.0	13.9		7	1	0			
145	HIGHLAND [AR]	Distribution	Unattended	161.0	69.0		30	1	1			
146	HIGHWAY #7	Distribution	Unattended	34.0	13.8		13	1	0			
147	HILO	Distribution	Unattended	115.0	13.8		5	1	0			
148	HUGHES	Distribution	Unattended	161.0	13.8		22	1	0			
149	HUTTIG	Distribution	Unattended	115.0	13.9		13	1	0			
150	IMBODEN	Distribution	Unattended	69.0	34.5		10	1	0			
151	IMBODEN JUNCTION	Distribution	Unattended	34.0	12.5		4	1	0			
152	INDEPENDENCE-ISES	Distribution	Unattended	500.0	13.9		20	1	0			
153	JACKSONVILLE NORTH	Distribution	Unattended	115.0	13.9		106	2	0			
154	JACKSONVILLE SOUTH	Distribution	Unattended	115.0	13.8		30	1	0			
155	JEFFERSON INDUSTRIAL	Distribution	Unattended	115.0	13.9		96	2	0			
156	JIM HILL	Distribution	Unattended	161.0	34.5		33	1	0			
157	JONESBORO [AR]	Distribution	Unattended	161.0	13.9		22	1	0			
158	KERLIN	Distribution	Unattended	115.0	13.9		33	2	0			
159	KINGSLAND	Distribution	Unattended	115.0	13.2		14	1	0			
160	KUHN ROAD	Distribution	Unattended	161.0	13.8		33	1	0			
161	L.R. 145TH ST	Distribution	Unattended	115.0	13.9		20	1	0			
162	L.R. 23RD & SPR	Distribution	Unattended	115.0	13.9		34	1	0			
163	L.R. 8TH & WOODROW	Distribution	Unattended	115.0	14.4		100	2	0			
164	L.R. ALEXANDER	Distribution	Unattended	115.0	13.9		117	3	0			
165	L.R. ARCH ST.	Distribution	Unattended	115.0	13.9		63	2	0			
166	L.R. BOYLE PARK	Distribution	Unattended	115.0	14.4		67	2	0			
167	L.R. BRINGLE	Distribution	Unattended	161.0	13.8		3	1	0			
168	L.R. CAMMACK	Distribution	Unattended	115.0	13.9		34	1	0			
169	L.R. CHICOT	Distribution	Unattended	115.0	13.9		63	2	0			
170	L.R. EAST	Distribution	Unattended	115.0	14.4		67	2	0			
171	L.R. FOURCHE	Distribution	Unattended	115.0	13.9		34	1	0			

172	L.R. GAINES	Distribution	Unattended	115.0	13.9		100	2	0			
173	L.R. GARLAND	Distribution	Unattended	115.0	13.8		112	2	0			
174	L.R. HINDMAN	Distribution	Unattended	115.0	13.9		34	1	0			
175	L.R. INDUSTRIAL	Distribution	Unattended	115.0	13.9		100	2	0			
176	L.R. KANIS RD	Distribution	Unattended	115.0	14.4		116	3	0			
177	L.R. MANN	Distribution	Unattended	115.0	13.9		20	1	0			
178	L.R. PALM STREET	Distribution	Unattended	115.0	13.8		50	1	0			
179	L.R. PINNACLE	Distribution	Unattended	161.0	13.8		83	2	0			
180	L.R. PORT	Distribution	Unattended	115.0	13.9		117	3	0			
181	L.R. ROCK CREEK	Distribution	Unattended	115.0	13.9		67	2	0			
182	L.R. ROLAND ROAD	Distribution	Unattended	115.0	13.9		13	1	0			
183	L.R. SOUTH	Distribution	Unattended	115.0	13.8		55	2	0			
184	L.R. WALTON HEIGHTS	Distribution	Unattended	115.0	13.9		100	2	0			
185	L.R. WEST	Distribution	Unattended	115.0	13.9		100	2	0			
186	L.R. WEST MARKHAM	Distribution	Unattended	115.0	13.9		156	3	0			
187	LAKE CHICOT PUMP STA	Distribution	Unattended	115.0	4.2		60	2	0			
188	LAKE CONWAY	Distribution	Unattended	115.0	14.4		71	2	0			
189	LAKE VILLAGE BAGBY	Distribution	Unattended	230.0	13.9		34	1	0			
190	LAKEWOOD	Distribution	Unattended	115.0	14.4		33	1	0			
191	LAMARTINE	Distribution	Unattended	115.0	13.9		23	2	0			
192	LAWSON ROAD	Distribution	Unattended	115.0	13.8		50	1	0			
193	LEACHVILLE	Distribution	Unattended	34.0	12.4		13	1	0			
194	LEPANTO	Distribution	Unattended	161.0	13.9		22	1	0			
195	LEWISVILLE	Distribution	Unattended	115.0	13.9		72	2	0			
196	LONDON	Distribution	Unattended	161.0	13.8		11	1	0			
197	LONDON NORTH	Distribution	Unattended	161.0	13.8		40	1	0			
198	LONOKE EAST	Distribution	Unattended	115.0	13.9		63	2	0			
199	LUNSFORD	Distribution	Unattended	69.0	13.8		11	1	0			
200	MACARTHUR	Distribution	Unattended	115.0	13.8		40	1	0			
201	MACEDONIA	Distribution	Unattended	115.0	13.8		33	1	0			
202	MAGNOLIA DOW	Distribution	Unattended	115.0	13.8		13	1	1			
203	MAGNOLIA EAST	Distribution	Unattended	115.0	13.8		33	1	0			
204	MAGNOLIA SOUTH	Distribution	Unattended	115.0	13.8		33	1	0			
205	MAGNOLIA WEST	Distribution	Unattended	115.0	13.9		34	1	0			
206	MALVERN NORTH	Distribution	Unattended	115.0	13.8		33	1	0			
207	MALVERN SOUTH	Distribution	Unattended	115.0	13.8		67	2	0			
208	MANILA	Distribution	Unattended	34.0	12.5		31	2	0			

209	MARIANNA	Distribution	Unattended	115.0	13.9		20	1	0			
210	MARION	Distribution	Unattended	161.0	13.8		47	2	0			
211	MARKED TREE	Distribution	Unattended	161.0	13.8		22	1	0			
212	MARMADUKE	Distribution	Unattended	34.0	12.5		5	1	0			
213	MARMADUKE ARI	Distribution	Unattended	34.0	12.5		11	1	0			
214	MARMADUKE RAIL	Distribution	Unattended	161.0	34.5		33	1	0			
215	MARSHALL	Distribution	Unattended	161.0	13.9		20	1	0			
216	MARVELL	Distribution	Unattended	115.0	13.8		10	1	0			
217	MAUMELLE EAST	Distribution	Unattended	115.0	13.9		67	2	0			
218	MAYFLOWER EHV	Distribution	Unattended	500.0	13.8		0	0	1			
219	MCALMONT	Distribution	Unattended	115.0	13.9		67	2	0			
220	MCCRORY	Distribution	Unattended	161.0	13.9		20	1	0			
221	MCGEHEE	Distribution	Unattended	115.0	13.9		30	1	0			
222	MCNEIL EHV	Distribution	Unattended	500.0	13.9		20	1	0			
223	MELBOURNE	Distribution	Unattended	161.0	13.9		22	1	0			
224	MONETTE	Distribution	Unattended	34.0	12.5		5	1	0			
225	MONETTE JUNCTION	Distribution	Unattended	161.0	34.5		75	2	0			
226	MONTICELLO EAST	Distribution	Unattended	115.0	13.8		34	1	0			
227	MONTICELLO SOUTH	Distribution	Unattended	115.0	13.9		30	1	0			
228	MONTROSE	Distribution	Unattended	115.0	34.5	13.9	47	2	0			
229	MOOREFIELD	Distribution	Unattended	161.0	13.9		74	2	0			
230	MORELAND	Distribution	Unattended	161.0	13.8		80	2	0			
231	MORGAN	Distribution	Unattended	115.0	13.9		63	2	0			
232	MORO	Distribution	Unattended	115.0	13.8		11	1	0			
233	MORRILTON EAST	Distribution	Unattended	161.0	13.9		34	1	0			
234	MORRILTON WEST	Distribution	Unattended	161.0	13.9		30	1	0			
235	MOUNT PLEASANT	Distribution	Unattended	161.0	13.8		10	1	0			
236	MOUNTAIN HOME	Distribution	Unattended	161.0	14.4		89	3	0			
237	MOUNTAIN VIEW	Distribution	Unattended	161.0	13.9		62	2	0			
238	MT IDA	Distribution	Unattended	115.0	34.5		34	1	0			
239	MT PINE NORTH	Distribution	Unattended	115.0	13.9		20	1	0			
240	MT PINE SOUTH	Distribution	Unattended	115.0	14.5		33	1	0			
241	N.L.R. DIXIE	Distribution	Unattended	115.0	13.9		100	2	0			
242	N.L.R. LEVY	Distribution	Unattended	115.0	13.9		83	2	0			
243	N.L.R. MCCAIN	Distribution	Unattended	115.0	13.8		33	1	0			
244	N.L.R. WESTGATE	Distribution	Unattended	115.0	13.9		67	2	0			
245	NEWARK	Distribution	Unattended	161.0	13.9		50	2	0			

246	NEWPORT	Distribution	Unattended	161.0	13.9		34	1	0			
247	NEWPORT AB	Distribution	Unattended	161.0	13.9		62	2	0			
248	NEWPORT IND	Distribution	Unattended	161.0	14.4		97	3	0			
249	OLA	Distribution	Unattended	115.0	13.8		33	2	0			
250	OMAHA	Distribution	Unattended	161.0	34.5		20	1	0			
251	OSCEOLA	Distribution	Unattended	161.0	13.9		46	2	0			
252	OSCEOLA INDUSTRIAL	Distribution	Unattended	161.0	13.8		33	1	0			
253	OSCEOLA NORTH	Distribution	Unattended	161.0	14.4		33	1	0			
254	P.B. 34TH & MAIN	Distribution	Unattended	115.0	13.9		30	1	0			
255	P.B. 4TH & CHESTNUT	Distribution	Unattended	14.0								
256	P.B. DIERKS	Distribution	Unattended	115.0	13.9		34	1	0			
257	P.B. EAST	Distribution	Unattended	115.0	13.9		63	2	0			
258	P.B. INDUSTRIAL SUB	Distribution	Unattended	115.0	13.9		58	2	0			
259	P.B. MCCAMANT	Distribution	Unattended	115.0	14.4		64	2	0			
260	P.B. PORT	Distribution	Unattended	115.0	13.8		33	1	0			
261	P.B. SOUTH	Distribution	Unattended	115.0	13.8		20	1	0			
262	P.B. WATSON CHAPEL	Distribution	Unattended	115.0	13.9		64	2	0			
263	P.B. WHITEHALL	Distribution	Unattended	115.0	13.9		30	1	0			
264	PANGBURN	Distribution	Unattended	161.0	13.9		20	1	0			
265	PARAGOULD	Distribution	Unattended	161.0	33.0		0	0	4			
266	PARKIN	Distribution	Unattended	161.0	13.8		20	1	0			
267	PECAN ST	Distribution	Unattended	161.0	13.8		40	1	0			
268	POCAHONTAS NORTH	Distribution	Unattended	161.0	34.5		33	1	0			
269	POCAHONTAS SOUTH	Distribution	Unattended	34.0	12.4		13	1	0			
270	POYEN	Distribution	Unattended	115.0	34.5		26	2	0			
271	PRESCOTT	Distribution	Unattended	115.0	13.9		42	2	0			
272	PROMISED LAND	Distribution	Unattended	34.0								
273	RAVENDEN	Distribution	Unattended	13.0								
274	RECTOR	Distribution	Unattended	161.0	34.5		37	1	0			
275	REYNO	Distribution	Unattended	34.0	4.2		1	1	0			
276	RICHWOOD	Distribution	Unattended	115.0	13.8		7	1	0			
277	RISON	Distribution	Unattended	115.0	13.9		9	1	0			
278	ROHWER	Distribution	Unattended	115.0	13.8		63	2	0			
279	RUSSELLVILLE EAST	Distribution	Unattended	161.0	13.8		100	2	0			
280	RUSSELLVILLE INDUSTRIAL	Distribution	Unattended	161.0	13.8		40	1	0			
281	RUSSELLVILLE NORTH	Distribution	Unattended	161.0	13.8		83	2	0			
282	RUSSELLVILLE SOUTH	Distribution	Unattended	161.0	13.9		80	2	0			

283	SEARCY PRICE	Distribution	Unattended	161.0	13.8		84	2	0			
284	SEARCY SOUTH	Distribution	Unattended	161.0	13.9		84	2	0			
285	SHERIDAN	Distribution	Unattended	115.0	13.9		30	1	0			
286	SHERRILL	Distribution	Unattended	115.0	13.9		7	1	0			
287	SHERWOOD	Distribution	Unattended	115.0	13.9		100	2	0			
288	SHOFFNER	Distribution	Unattended	161.0	13.8		7	1	0			
289	SHULER	Distribution	Unattended	115.0	13.9		33	2	0			
290	SMACKOVER	Distribution	Unattended	115.0	13.9		13	1	0			
291	SMACKOVER INDUSTRIAL	Distribution	Unattended	115.0	13.8		33	1	0			
292	SOCIAL HILL	Distribution	Unattended	115.0	13.8		40	1	0			
293	SOUTH LEAD HILL	Distribution	Unattended	161.0	34.5		20	1	0			
294	SOUTHSIDE	Distribution	Unattended	161.0	13.9		40	2	0			
295	ST. FRANCIS	Distribution	Unattended	34.0	2.3		1	1	0			
296	ST. JOE	Distribution	Unattended	161.0	13.8		3	1	0			
297	ST. VINCENT	Distribution	Unattended	161.0	13.9		20	1	0			
298	STEPHENS	Distribution	Unattended	115.0	13.9		10	1	0			
299	STRAWBERRY	Distribution	Unattended	24.0	2.4		4	1	0			
300	STRONG	Distribution	Unattended	115.0	13.9		46	2	0			
301	STUTTART INDUSTRIAL	Distribution	Unattended	115.0	14.4		66	2	0			
302	STUTTART NORTH	Distribution	Unattended	115.0	13.8		30	1	0			
303	STUTTART RICUSKEY	Distribution	Unattended	230.0	13.8		63	2	0			
304	SUMMIT	Distribution	Unattended	161.0	13.9		62	2	0			
305	SWIFTON	Distribution	Unattended	161.0	13.8		22	1	0			
306	TARLETON	Distribution	Unattended	230.0	13.8		40	2	0			
307	TAYLOR	Distribution	Unattended	115.0	13.9		7	1	0			
308	THAYER NORTH	Distribution	Unattended	69.0	4.2		7	2	0			
309	THAYER SOUTH	Distribution	Unattended	161.0	12.5		11	1	0			
310	TRUMANN	Distribution	Unattended	161.0	13.9		20	1	0			
311	TWIST	Distribution	Unattended	161.0	13.9		5	1	0			
312	ULM	Distribution	Unattended	115.0	13.9		20	1	0			
313	VARNER	Distribution	Unattended	115.0	13.9		33	2	0			
314	VILONIA	Distribution	Unattended	161.0	13.8		40	1	0			
315	WABBASEKA	Distribution	Unattended	115.0	13.9		13	1	0			
316	WALCOTT	Distribution	Unattended	34.0	13.2		2	1	0			
317	WALNUT RIDGE 161/115 SUB	Distribution	Unattended	161.0	34.5		71	2	0			
318	WALNUT RIDGE MANSON RD	Distribution	Unattended	34.0	2.3		2	1	0			
319	WALNUT RIDGE NORTH	Distribution	Unattended	34.0	12.5		11	1	0			

320	WALNUT RIDGE PLANT	Distribution	Unattended	34.0	12.5		20	1	0			
321	WARREN EAST	Distribution	Unattended	115.0	33.0		33	2	0			
322	WARREN WEST	Distribution	Unattended	115.0	13.8		20	1	0			
323	WEST HELENA	Distribution	Unattended	115.0	13.9		34	1	0			
324	WEST MEMPHIS DOVER	Distribution	Unattended	161.0	13.9		34	1	0			
325	WEST MEMPHIS GATEWAY	Distribution	Unattended	161.0	13.8		30	1	0			
326	WEST MEMPHIS LEHI	Distribution	Unattended	161.0	13.9		56	2	0			
327	WHELEN SPRINGS	Distribution	Unattended	34.0	12.5		3	1	0			
328	WILMAR	Distribution	Unattended	115.0	13.9		7	1	0			
329	WILMOT	Distribution	Unattended	34.0	13.8		20	1	0			
330	WILSON	Distribution	Unattended	161.0	13.9		20	1	0			
331	WOODWARD 115 SUB	Distribution	Unattended	115.0	13.8		33	1	0			
332	WYNNE INDUSTRIAL	Distribution	Unattended	161.0	13.9		45	2	0			
333	WYNNE SOUTH	Distribution	Unattended	161.0	13.9		53	2	0			
334	ANO SWYD	Transmission	Unattended	500.0	161.0	4.2	672	1	1			
335	ASHLEY	Transmission	Unattended	115.0								
336	BELLAIRE SS	Transmission	Unattended	115.0								
337	BENTON WEST	Transmission	Unattended	115.0								
338	BOB WHITE	Transmission	Unattended	161.0								
339	BRINKLEY EAST	Transmission	Unattended	230.0	120.0	13.9	616	3	0			
340	CHEETAH	Transmission	Unattended	115.0								
341	CONWAY WEST	Transmission	Unattended	161.0	115.5	13.9	224	1	0			
342	CROSSETT SOUTH SS	Transmission	Unattended	115.0								
343	DANVILLE [AR]	Transmission	Unattended	161.0	115.5	13.9	140	1	0			
344	DELL EHV	Transmission	Unattended	500.0	161.0	13.8	1344	2	0			
345	DOYLESTOWN	Transmission	Unattended	115.0								
346	DRIVER	Transmission	Unattended	500.0	230.0	34.5	1500	2	0			
347	EBONY SS	Transmission	Unattended	161.0								
348	EL DORADO EHV	Transmission	Unattended	500.0	345.0	13.8	1791	3	0			
349	ETTA	Transmission	Unattended	500.0								
350	FALLS	Transmission	Unattended	161.0								
351	FLAT FORK	Transmission	Unattended	230.0								
352	FLAT LAKE	Transmission	Unattended	161.0								
353	GALLOWAY	Transmission	Unattended	115.0								
354	GOODWIN RD	Transmission	Unattended	115.0								
355	GRANDVIEW	Transmission	Unattended	161.0								
356	H.S. EHV	Transmission	Unattended	500.0	115.0		1105	3	0			

357	HAMLET SS	Transmission	Unattended	161.0								
358	HAMRICK	Transmission	Unattended	161.0								
359	HAPPY	Transmission	Unattended	115.0								
360	HAYTI SOUTH	Transmission	Unattended	161.0								
361	HETH	Transmission	Unattended	500.0								
362	HILL TOP	Transmission	Unattended	161.0								
363	HOLLAND BOTTOM	Transmission	Unattended	500.0	161.0		1200	2	0			
364	HURRICANE LAKE	Transmission	Unattended	115.0								
365	INDEPENDENCE-ISES	Transmission	Unattended	500.0	161.0	34.5	1600	2	0			
366	JUNCTION CITY	Transmission	Unattended	115.0								
367	KEO EHV	Transmission	Unattended	500.0								
368	L.R. PINNACLE	Transmission	Unattended	161.0	115.5	13.8	225	1	0			
369	LAKE VILLAGE BAGBY	Transmission	Unattended	230.0	120.0	13.8	448	1	0			
370	LEE	Transmission	Unattended	115.0								
371	LOCUST CREEK	Transmission	Unattended	161.0								
372	LYNCH SWYD	Transmission	Unattended	115.0								
373	MABELVALE EHV	Transmission	Unattended	500.0	115.0	13.8	1200	2	0			
374	MAGNET COVE	Transmission	Unattended	500.0								
375	MALLORY	Transmission	Unattended	161.0								
376	MARSTON	Transmission	Unattended	161.0								
377	MAYFLOWER EHV	Transmission	Unattended	500.0	115.0		1260	3	0			
378	MCNEIL EHV	Transmission	Unattended	500.0	115.0		600	1	0			
379	MOSES SWYD	Transmission	Unattended	161.0								
380	MURFREESBORO SOUTH	Transmission	Unattended	138.0	115.0	13.8	150	1	0			
381	OUACHITA (COGENTRIX)	Transmission	Unattended	500.0								
382	P.B. INTERNATIONAL PAPER SS	Transmission	Unattended	115.0								
383	PARAGOULD	Transmission	Unattended	161.0	115.5	13.9	125	1	0			
384	PLEASANT HILL	Transmission	Unattended	500.0	161.0		600	1	0			
385	POWERLINE ROAD	Transmission	Unattended	500.0	161.0	13.8	800	1	0			
386	PRAIRIE CREEK	Transmission	Unattended	161.0								
387	QUITMAN	Transmission	Unattended	161.0								
388	REED SS	Transmission	Unattended	115.0								
389	RITCHIE SWYD	Transmission	Unattended	230.0	115.0	13.8	112	1	0			
390	RIVER RIDGE	Transmission	Unattended	115.0								
391	SAN SOUCI	Transmission	Unattended	500.0								
392	SEARCY PRICE	Transmission	Unattended	161.0	115.5	13.8	225	1	0			
393	SHERIDAN EHV	Transmission	Unattended	500.0								

394	STEELE	Transmission	Unattended	161.0								
395	STUTT GART RICUSKEY	Transmission	Unattended	230.0	120.0		448	1	0			
396	SYLVAN HILLS	Transmission	Unattended	161.0	115.5	13.9	140	1	0			
397	THAYER SOUTH	Transmission	Unattended	161.0	69.0	13.8	50	1	0			
398	UNION POWER STATION	Transmission	Unattended	500.0								
399	WALNUT RIDGE 161/115 SUB	Transmission	Unattended	161.0	115.5	34.5	100	1	1			
400	WEST MEMPHIS EHV	Transmission	Unattended	500.0	161.0		450	1	0			
401	WEST MEMPHIS POLK AVE	Transmission	Unattended	161.0								
402	WHITE BLUFF EHV	Transmission	Unattended	500.0	230.0	0.0	1170	2	0			
403	WOODLAWN	Transmission	Unattended	115.0								
404	WOODWARD 115 SUB	Transmission	Unattended	115.0	230.0	13.8	300	1	0			
405	WOODWARD 230 SUB	Transmission	Unattended	230.0								
406	WRIGHTSVILLE	Transmission	Unattended	500.0	115.0		448	1	0			
407	WYATT	Transmission	Unattended	115.0								
409	TotalDistributionSubstationMember											333
410	TotalGenerationSubstationMember											0
411	TotalTransmissionSubstationMember											74
412	Total											407

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: PrimaryVoltageLevel
Voltage in columns (c), (d), and (e) is reported in KV and not Mva.
(b) Concept: SecondaryVoltageLevel
Voltage in columns (c), (d), and (e) is reported in KV and not Mva.
(c) Concept: TertiaryVoltageLevel
Voltage in columns (c), (d), and (e) is reported in KV and not Mva.

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
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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	Support - Corporate	Entergy Services, LLC	107000, 108220, 108230, 118001, 120600, 152000, 163000, 174101, 174104, 174200, 181CPD, 182300, 183000, 183KSL, 184001, 1840FS, 1840NC, 184EPC, 184EST, 18624E, 186PTR, 228100, 4031AM, 408110, 408155, 408158, 417100, 426100, 426300, 426400, 426500, 454000, 500000, 501000, 506000, 510000, 513000, 513100, 513200, 517000, 519000, 520000, 524000, 528000, 530000, 531100, 531200, 532000, 535000, 539000, 546000, 549000, 551000, 552000, 5531CH, 553200, 558100, 558140, 558200, 558700, 558900, 560000, 561200, 561300, 561500, 563000, 566000, 567000, 568000, 569100, 569200, 580000, 581000, 583000, 584000, 585000, 586000, 587000, 588000, 590000, 592000, 592200, 592300, 592400, 593000, 594000, 596000, 597000, 598000, 901000, 902000, 903001, 903002, 904000, 905000, 907000, 908000, 909000, 910000, 911000, 912000, 916000, 920000, 921000, 922000, 923000, 924000, 925000, 926000, 926NS1, 928000, 930100, 930200, 931000, 935000, 935100, 935200, 935300	128,425,520
3	Support - Finance and Accounting	Entergy Services, LLC	107000, 108220, 152000, 163000, 174101, 174104, 181CPD, 182300, 183KSL, 184001, 1840FS, 1840NC, 18624E, 186PTR, 408110, 426100, 426300, 426400, 426500, 500000, 506000, 517000, 524000, 532000, 539000, 549000, 560000, 566000, 580000, 586000, 588000, 592000, 901000, 902000, 903001, 903002, 905000, 908000, 910000, 911000, 912000, 920000, 921000, 922000, 923000, 924000, 925000, 925INS, 926000, 928000, 930100, 930200, 931000, 935000, 935100, 935200	29,937,553
4	Support - Power Generation	Entergy Services, LLC	107000, 108220, 163000, 174101, 174200, 182300, 183000, 183KSL, 186PTR, 408110, 417100, 426100, 426500, 500000, 501000, 506000, 507000, 510000, 513000, 513200, 514000, 517000, 531200, 535000, 539000, 541000, 546000, 549000, 551000, 552000, 553000, 5531CH, 553200, 558100, 558140, 558200, 558700, 558900, 920000, 921000, 922000, 923000, 926000, 926NS1, 928000, 930100, 930200, 935100, 935200	27,051,947

5	Support - Information Technology	Entergy Services, LLC	107000, 108230, 152000, 163000, 174101, 174104, 174200, 182300, 183KSL, 184001, 1840FS, 1840NC, 184EPC, 184EST, 186PTR, 408110, 426400, 426500, 454000, 500000, 506000, 513100, 513200, 517000, 524000, 531100, 531200, 531300, 532000, 539000, 549000, 5531CH, 553200, 553300, 560000, 566000, 567000, 568000, 569100, 569200, 5693CE, 573000, 580000, 581000, 583000, 584000, 585000, 586000, 587000, 588000, 590000, 592000, 592200, 592300, 592400, 593000, 594000, 596000, 597000, 598000, 902000, 903001, 903002, 908000, 921000, 922000, 923000, 926000, 930100, 930200, 931000, 935000, 935100, 935200, 935300	68,468,345
6	Support - Nuclear	Entergy Services, LLC	107000, 120600, 163000, 174104, 182300, 1840NC, 186PTR, 408110, 426400, 426500, 517000, 518500, 519000, 520000, 524000, 525000, 528000, 530000, 531100, 531200, 532000, 920000, 921000, 922000, 923000, 926000, 928000, 930100, 930200, 935000	27,422,303
7	Support - Power Delivery	Entergy Services, LLC	107000, 108220, 108230, 152000, 154PAS, 163000, 174101, 174200, 182300, 183KSL, 184001, 1840FS, 1840NC, 186PTR, 228100, 228400, 408110, 426100, 426400, 426500, 560000, 561200, 561500, 563000, 565400, 566000, 567000, 568000, 569000, 569100, 569200, 5693CE, 573000, 580000, 581000, 584000, 586000, 588000, 589000, 590000, 591000, 592000, 592200, 592300, 592400, 593000, 596000, 597000, 598000, 901000, 902000, 903001, 903002, 905000, 909000, 910000, 912000, 913000, 916000, 920000, 921000, 922000, 923000, 925000, 926000, 928000, 930100, 930200, 931000	65,987,421
8	Support - President/CEO	Entergy Services, LLC	107000, 174101, 182300, 184001, 186PTR, 408110, 560000, 568000, 580000, 586000, 588000, 592000, 592300, 901000, 903001, 903002, 905000, 907000, 908000, 910000, 911000, 912000, 913000, 916000, 920000, 921000, 922000, 923000, 926000, 930100, 930200, 931000, 935100, 935200	12,318,491
9	Support - Corporate	Entergy Operations, Inc.	107000, 108230, 120600, 154DCS, 163000, 174104, 174201, 4031AM, 4041AM, 408110, 408142, 426100, 517000, 519000, 520000, 524000, 528000, 530000, 531000, 531100, 531200, 531300, 532000, 568000, 920000, 921000, 925000, 925INS, 926000, 926NS1, 930200	33,392,036
10	Support - Nuclear	Entergy Operations, Inc.	107000, 120600, 154DCS, 163000, 174104, 408110, 4212AM, 426500, 517000, 519000, 520000, 524000, 525000, 528000, 530000, 531000, 531100, 531200, 531300, 532000, 920000, 921000, 922000, 923000, 926000, 926NS1, 935100, 935200	163,814,045
11	Loaned Labor and Associated Loaders	Entergy Louisiana, LLC	107000, 152000, 184001, 408110, 500000, 502000, 506000, 512000, 513000, 514000, 546000, 548000, 549000, 551000, 552000, 553000, 554000, 558700, 562000, 570000, 580000, 583000, 587000, 592000, 593000, 594000, 596000, 903001, 926000, 926NS1	4,597,583
12	Storm Support	Entergy Louisiana, LLC	174101, 408110, 549000, 926000, 926NS1	495,276
13	Loaned Labor and Associated Loaders	Entergy Mississippi, LLC	107000, 186000, 408110, 500000, 546000, 548000, 580000, 581000, 583000, 584000, 586000, 587000, 590000, 592000, 593000, 594000, 596000, 598000, 902000, 926000, 926NS1	85,949
14	Storm Support	Entergy Mississippi, LLC	107000, 174101	364,075

15	Loaned Labor and Associated Loaders	Entergy Texas, Inc	107000, 186000, 408110, 500000, 506000, 543000, 560000, 587000, 590000, 593000, 594000, 596000, 902000, 926000, 926NS1	36,596
16	Storm Support	Entergy Texas, Inc	107000, 174101	593,190
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Loaned Labor and Associated Loaders	Entergy Louisiana, LLC	107000, 108230, 408110, 500000, 512000, 546000, 548000, 549000, 551000, 552000, 553000, 554000, 562000, 580000, 583000, 586000, 587000, 588000, 593000, 594000, 596000, 598000, 902000, 903002, 926000, 926NS1	5,765,570
22	Storm Support	Entergy Louisiana, LLC	174101, 408110, 549000, 926000, 926NS1	1,953,363
23	Loaned Labor and Associated Loaders	Entergy Mississippi, LLC	107000, 108230, 152000, 408110, 500000, 502000, 506000, 512000, 513000, 514000, 563000, 570000, 580000, 581000, 583000, 584000, 587000, 590000, 593000, 922000, 926000, 926NS1, 935300	46,136
24	Storm Support	Entergy Mississippi, LLC	174101	725,486
25	Loaned Labor and Associated Loaders	Entergy New Orleans, LLC	107000, 408110, 546000, 548000, 549000, 551000, 5520000, 553000, 554000, 580000, 593000, 594000, 926000, 926NS1	3,122,669
26	Storm Support	Entergy New Orleans, LLC	174101, 408110, 549000, 926000, 926NS1	9,277
27	Loaned Labor and Associated Loaders	Entergy Texas, Inc	107000, 408110, 549000, 580000, 583000, 584000, 587000, 593000, 594000, 902000, 926000, 926NS1	171,036
28	Storm Support	Entergy Texas, Inc	174101	88,400
29	See Footnote for allocation factors			
42				

Name of Respondent: Entergy Arkansas, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/03/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfNonPowerGoodOrService

Listed below are the allocation factors used to allocate costs to the affiliate.
 Note: Where no allocation factor is provided for the non-power goods or services listed on Schedule 429, the costs associated with those goods and services were directly charged and not allocated.

Description of the Non-Power Good or Service	Cost Allocator(s)
Entergy Services, LLC	
Support - Corporate	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, ASTREGOP, BNKACCTA, CAPACCGT, CAPAOPCO, CAPRENEW, CAPXCOPC, COALARGS, COMCLAIM, CUSEGAMI, CUSEGTX, CUSEOPCO, CUSTCALL, CUSTEGOP, DIRCANO1, DIRCANO2, DIRCANOC, DIRCTEAI, DIRCTEOI, DSTLNALL, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLUTOP, EMPXRTNC, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVICAL, MACCTALL, MACCTNLA, NETPPEAL, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PRCHKALL, PWRSNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCDTMLS, SCMATRAN, SCPSPALL, SCPSPXNC, SCRSPALL, SCTSPALL, SNSITEAL, SNUCSITE, SNUCUNIT, SNUNITAL, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRLNOPXN, TRSBLNOP, VEHCLEFOS, VEHCLENUC, VEHCLEUSG
Support - Finance and Accounting	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, CAPXCOPC, CUSEGAMI, CUSEGTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, DIRCANO1, DIRCANO2, DIRCANOC, DIRCTEAI, DIRCTEOI, EMPLOREG, EMPLOYAL, EMPLPRES, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRUTOPN, LVLSVICAL, MACCTALL, NETPPEAL, OWNISFI, PKLOADAL, PRCHKALL, SCMATRAN, SCPSPALL, SNUCSITE, SNUCUNIT, SNUNITAL, TRANSPND, TRSBLNOP, VEHCLEFOS, VEHCLENUC, VEHCLEUSG
Support - Power Generation	APPSUPAL, ASSTSALL, ASSTSREG, ASTREGOP, CAPACCGT, CAPAOPCO, CAPRENEW, CAPXCOPC, COALARGS, CUSEGAMI, CUSEOPCO, CUSTEGOP, DIRCTEAI, EMPLFRAN, EMPLOYAL, GENLDREG, GENLEDAL, ITSPENDA, LBRBILAL, LBRFDPOL, LBRSUPCN, LBRUTOPN, LVLSVICAL, MACCTALL, NETPPEAL, PCNUMALL, PKLOADAL, SCDSPALL, SCFSPALL, SCPSPALL, SNUCSITE, TELPHALL
Support - Information Technology	APPSMVX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPACCGT, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, DIRCANO1, DIRCANO2, DIRCANOC, DIRCTEAI, DIRCTEOI, DSTLNALL, EMPLOYAL, EMPXRTNC, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRLEGAL, LBRSUPCN, MACCTALL, NETPPEAL, PCNUMALL, PCNUMXNR, PKLOADAL, PRCHKALL, RADIOALL, RECDMGNT, SCDSPALL, SCDTMLS, SCFSPALL, SCRSPALL, SNSITEAL, SNUCSITE, SNUNITAL, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP
Support - Nuclear	APPSUPAL, ASSTSALL, ASSTSREG, CAPAOPCO, DIRCANO1, DIRCANO2, DIRCANOC, DIRCTEAI, DIRCTEOI, EMPLOYAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRLEGAL, NETPPEAL, PKLOADAL, PWRSNUCA, SCDSPALL, SCFSPALL, SCPSPALL, SNSITEAL, SNUCSITE, SNUCUNIT, SNUNITAL, TRANSPND, TRSBLNOP
Support - Power Delivery	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTCALL, CUSTEGOP, DIRCTEAI, DSTLNALL, EMPLFRAN, EMPLOREG, EMPLOYAL, EMPLUTOP, GENLDREG, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRFDPOL, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVICAL, MACCTALL, NETPPEAL, PCNUMXNR, PKLOADAL, PRCHKALL, SCDSPALL, SCFSPALL, SCMATRAN, SCTDSPAL, SCTSPALL, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRLNOPXN, TRSBLNOP, VEHCLEFOS, VEHCLENUC, VEHCLEUSG
Support - President/CEO	APPSUPAL, ASSTSALL, ASSTSREG, CAPAOPCO, CUSEGAMI, CUSEGTX, CUSEOPCO, CUSTCALL, CUSTEGOP, DIRCTEAI, EMPLOYAL, GENLEDAL, ITSPENDA, LBRBILAL, LBRFDPOL, MACCTALL, MACCTNLA, NETPPEAL, PCNUMALL, PKLOADAL, SCMATRAN, TRANSPND, VEHCLEUSG
Entergy Operations, Inc.	
Support - Corporate	DIRCANO1, DIRCANO2, DIRCANOC, DIRCTEOI, SPLEOIP, SPLEUNIT, SPLPLXRB, SPLXRBS
Support - Nuclear	DIRCANO1, DIRCANO2, DIRCANOC, EMPLOEAI, PWRSANWF, SPLEOIP, SPLEUNIT, SPLPLXRB, SPLXRBS

Cost Allocator Descriptions

Cost Allocator	Cost Allocator Title	Cost Allocator Description
Entergy Services, LLC		
APPSMVX	Server and Mainframe Usage - MVS	Based on mainframe usage
APPSUNIX	Server and Mainframe Usage - UNIX	Based on the UNIX server usage
APPSUPAL	Server and Mainframe Usage - Composite	Based on a weighted composite of UNIX and NT servers and mainframe usage
APPSWINT	Server and Mainframe Usage - NTS	Based on WINTEL server usage
APTRNALL	Accounts Payable Transactions	Based on a twelve month number of accounts payable transactions processed
ARTRNALL	Accounts Receivable Invoices	Based on a twelve month number of accounts receivable transactions processed
ASSTSALL	Total Assets	Based on the total assets at period end
ASSTSREG	Total Assets - Regulated BU's	Based on total assets at period end for all regulated Business Units
ASTREGOP	Total Assets - Regulated BUs, excluding SERI	Based on total assets at period end for all regulated Business Units, excluding SERI
BNKACCTA	Bank Accounts	Based on the number of bank accounts at period end
CAPACCGT	System Capacity - CCGT	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously (CCGT)

CAPAOPCO	System Capacity	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously
CAPRENEW	System Capacity - Renewable	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously (Renewable)
CAPXCOPC	System Capacity - Excluding Coal and Nuclear	Based on the power level, in kilowatts, that could be achieved if all non-coal and non-nuclear generating units were operating at maximum capability simultaneously
COALARGS	Coal Consumption	Based on the quantity of tons of coal delivered to each coal plant within the Entergy System
COMCLAIM	Workers' Compensation Claims	Based on number of open workers' compensation claims
CUSEGAMI	Customers - AMI Only	Based on a twelve-month average number of electric-only, gas-only, and dual (electric and gas) customers derived from the number of gas-only customers provided by Gas Operations. This method should only be used to allocate Advanced Metering Infrastructure (AMI) deployment infrastructure expense. (Does not include meter hardware purchases)
CUSEGTX	Electric and Gas Customers - Excluding ETI	Based on a twelve-month average number of electric and gas residential, commercial, industrial, government, municipal, and general business customers, excluding ETI
CUSEOPCO	Electric Customers	Based on a twelve-month average number of electric residential, commercial, industrial, government, and municipal customers
CUSTCALL	Customer Call Centers	Based on a twenty-four month average of customer calls
CUSTEGOP	Electric and Gas Customers	Based on a twelve-month average number of electric and gas residential, commercial, industrial, government, and municipal general business customers
CUSTEXTX	Electric Customers - Excluding ETI	Based on a twelve-month average number of electric residential, commercial, industrial, government, and municipal customers for EAI, ELA, EMI, and ENOI
DIRCANO1	100% to EAI - ANO Unit 1	Bill 100% to Entergy Arkansas, Inc. (BU A0000) - ANO
DIRCANO2	100% to EAI - ANO Unit 2	Bill 100% to Entergy Arkansas, Inc. (BU A0000) - ANO2
DIRCANOC	100% to EAI - ANC	Bill 100% to Entergy Arkansas, Inc. (BU A0000) - ANC
DIRCTEAI	100% to EAI (BU A0000)	Bill 100% to Entergy Arkansas, Inc. (BU A0000)
DIRCTEOI	100% to EOI (BU E0000)	Bill 100% to Entergy Operations, Inc. (BU E0000)
DSTLNALL	Distribution Line Miles	Based on the number of miles of distribution lines
EMPLFRAN	Employees - Franchise Operations	Based on the number of full-time and part-time employees within Franchise Operations
EMPLOCSS	Employees - Customer Support Services	Based on the number of full-time and part-time employees within Customer Support Service
EMPLOFOS	Employees - Fossil Plant Operations	Based on the number of full-time and part-time employees within Fossil Plant Operations
EMPLOREG	Full-Time and Part-Time Employees - EAI, ELA, EMI, ENOI, SERI, ETI and ESI	Based on the number of full-time and part-time employees at period end for EAI, ELA, EMI, ENOI, SERI, ETI and ESI
EMPLOYAL	Full-Time and Part-Time Employees	Based on the number of full time and part time employees at period end
EMPLPRES	Employees - State President	Based on the number of full-time and part-time employees within State President Organizations
EMPLTRAN	Employees - Transmission	Based on the number of full-time and part-time employees within Transmission
EMPLUTOP	Employees - Utility Operations	Based on the number of full-time and part-time employees within Utility Operations
EMPXRTNC	Regulated Employees	Based on the number of full-time and part-time employees at period end for EAI, ELA, EMI, ENOI, ETI, and ESI (excluding Nuclear)
GENLDREG	General Ledger Transactions - Regulated Companies	Based on general ledger transactions for regulated companies
GENLEDAL	General Ledger Transactions	Based on the general ledger transactions
GWHOCPPE	GWH Energy Sales	Based on energy sales to ultimate customers
INSPREAL	Insurance Premiums	Based on non nuclear insurance premiums
ITSPENDA	Information Technology Total Spending	Based on Information Technology twelve-month total spending
LBRBILAL	ESL Labor Costs Billed	Based on total labor dollars billed to each Client Company by ESL
LBRCOMUN	ESL Labor Billed - Communications	Based on total labor dollars billed to each company by ESL for the Communications function
LBRCORPT	ESL Labor Billed - Corporate	Based on total labor dollars billed to each company by ESL for the Corporate function
LBRFDPOL	ESL Labor Billed - Federal Policy, Regulatory and Governmental Affairs	Based on total labor dollars billed to each company by ESL for the Federal Policy, Regulatory and Governmental Affairs function
LBRFINAN	ESL Labor Billed - Finance	Based on total labor dollars billed to each company by ESL for the Finance function
LBRINFOR	ESL Labor Billed - IT	Based on total labor dollars billed to each company by ESL for the IT function
LBRLEGAL	ESL Labor Billed - Legal	Based on total labor dollars billed to each company by ESL for the Legal function
LBRSUPCN	ESL Labor Billed - Supply Chain	Based on total labor dollars billed to each company by ESL for the Supply Chain function
LBRUTOPN	ESL Labor Billed - Utility Operations	Based on total labor dollars billed to each company by ESL for the Utility Operations function
LVLVICAL	ESL Service Level	Based on ESL total billings to each Client Company
MACCTALL	Managed Accounts	Based on number of retail managed accounts

MACCTNLA	Managed Accounts - EAI, EMI, and ETI	Based on number of retail managed accounts, excluding accounts at all Louisiana companies
NETPPEAL	Net Property, Plant, and Equipment	Based on the net book value of all companies with property, plant and equipment - excluding natural gas and nuclear fuel
OWNISFI	Percentage Ownership - SFI	Based on the percentage ownership of SFI
PCNUMALL	Number of PC's	Based on the number of PC's within each Business Unit
PCNUMXNR	Number of PC's - Excluding Non-Regulated BU's	Based on the number of PC's within each regulated Business Unit at EAI, ELA, EMI, ENOI, SERI, ETI and ESI
PKLOADAL	Peak Load Ratio	Based on the ratio of each Client Company's load to the peak load at time of all companies peak load. The calculation of Peak Load Ratio is performed using a twelve-month rolling average of the coincident peaks.
PRCHKALL	Payroll Checks Issued	Based on the number of payroll checks issued for each Business Unit
PWRSNUCA	Pressure Water Reactor Units	Based on the number of Pressure Water Reactor Plant Units
RADIOALL	Radio Usage	Based on usage of Entergy's 2-way radio system
RECDMGNT	Records Management	Based on the number of full-time and part time employees at period end, excluding the Nuclear function using records management services
SCDSPALL	Supply Chain Spending - Distribution	Based on Supply Chain Procurement Total Spending for the Distribution Function
SCFSPALL	Supply Chain Spending - Fossil	Based on Supply Chain Procurement Total Spending for the Fossil Function
SCLDTMLS	Supply Chain - Labor Dollars	Based on Supply Chain Labor Dollars for the Transformer, Meter, and Light Shops
SCMATRAN	Supply Chain Transactions in Passport	Based on the number of Supply Chain materials transactions for each Business Unit in Passport
SCSPALL	Supply Chain Total Spending	Based on Supply Chain's Procurement Total Spending
SCSPXNC	Supply Chain Spending - Excluding Nuclear	Based on Supply Chain Procurement Total Spending, excluding Nuclear for twelve months
SCRSPALL	Supply Chain Spending - Regulated Companies	Based on Supply Chain Procurement Total Spending for the Regulated Companies
SCTSPALL	Supply Chain Spending - Transmission	Based on Supply Chain's Procurement Total Spending for Transmission
SNSITEAL	Nuclear Plants Sites - All	Based on the total number of Nuclear Plant Sites
SNUCSITE	Nuclear Plant Sites - Operating	Based on the number of operating Nuclear Plant Sites
SNUCUNIT	Nuclear Units - Operating	Based on the number of operating Nuclear Units
SNUNITAL	Nuclear Units - All	Based on the total number of Nuclear Units
SQFTALLC	Square Footage - All Companies	Based on square footage for all Business Units
TELPBALL	Number of Telephones	Based on number of telephones within each Business Unit
TRALINOP	Transmission Line Miles	Based on the number of miles of transmission lines, weighted for design voltage (Voltage < 400kv = 1; Voltage >400kv =2)
TRANSPND	Transmission Budgeted Capital Expenditures	Based on Transmission Budgeted Capital Expenditures
TRASUBOP	Transmission Substations	Based on the number of high voltage substations weighted for Voltage (Voltage < 500kv = 1; Voltage >= 500kv = 2)
TRLNOPXN	Transmission Line Miles - Excluding ENOL	Based on the number of miles of transmission lines, weighted for design voltage (Voltage < 400kv = 1; Voltage >400kv =2), excluding ENOL
TRSBLOP	Transmission Line Miles/Substation	Based on two components: Transmission Line Miles (30% weighting) and the Number of High Voltage Substations (70% weighting)
VEHCLFOS	Number of Vehicles - Fossil	Based on the number of vehicles owned or leased by each Business Unit for the Fossil function only
VEHCLNUC	Number of Vehicles - Nuclear	Based on the number of vehicles owned or leased by each Business Unit for the Nuclear function only
VEHCLUSG	Number of Vehicles - Excluding Fossil and Nuclear	Based on the number of vehicles owned or leased by each Business Unit that participates in the usage based transportation allocation, excluding Fossil and Nuclear
Entergy Operations, Inc.		
DIRCANO1	100% to EAI - ANO Unit 1	Bill 100% to Entergy Arkansas, Inc. (BU A0000) - ANO
DIRCANO2	100% to EAI - ANO Unit 2	Bill 100% to Entergy Arkansas, Inc. (BU A0000) - ANO2
DIRCANOC	100% to EAI - ANC	Bill 100% to Entergy Arkansas, Inc. (BU A0000) - ANC
EMPLOEOI	Nuclear South Site Employees	Based on Nuclear South Site employees
SPLIOIPL	Nuclear South Plant Sites	Based on the number of Nuclear South Plant Sites
SPLIUNIT	Nuclear South Units	Based on the total number of Nuclear South Units
SPLPLXRB	Split among ANC (33%), WF3 (33%), and GG1 (33%)	Split among ANC (33%), WF3 (33%), and GG1 (33%)
SPLLXRBS	Nuclear South Units - Excluding RBS	Based on the number of operating Nuclear south units, excluding Riverbend Station
PWRSANWF	Pressure Water Reactor Sites	Based on the number of Pressure Water Reactor Plant Sites

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