

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)



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, Inc.

Year/Period of Report

End of 2017/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

- (1) one million megawatt hours of total annual sales,
- (2) 100 megawatt hours of annual sales for resale,
- (3) 500 megawatt hours of annual power exchanges delivered, or
- (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp>. The software is used to submit the electronic filing to the Commission via the Internet.

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

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

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

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

The CPA Certification Statement should:

- a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

<u>Reference 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

- e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____, we have also reviewed schedules _____ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- (f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at <http://www.ferc.gov/help/how-to.asp>.

- (g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/forms.asp#3Q-gas>.

IV. When to Submit:

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

- a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

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

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

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

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

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

(4) 'Person' means an individual or a corporation;

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

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

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be 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 salt 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).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Entergy Arkansas, Inc.		02 Year/Period of Report End of <u>2017/Q4</u>	
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 Capitol Avenue, Little Rock, Arkansas 72201			
05 Name of Contact Person Gina G. Bellott		06 Title of Contact Person Sr. Lead 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) 576-6753	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) / /

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 Alyson M. Mount	03 Signature Alyson M. Mount	04 Date Signed (Mo, Da, Yr) 04/16/2018
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.

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)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	NA
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NA
25	Unrecovered Plant and Regulatory Study Costs	230	NA
26	Transmission Service and Generation Interconnection Study Costs	231	NA
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NA
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	NA
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	NA
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NA
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	NA
66	Generating Plant Statistics Pages	410-411	

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	NA
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	NA
	<p>Stockholders' Reports Check appropriate box:</p> <p><input type="checkbox"/> Two copies will be submitted</p> <p><input checked="" type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2017/Q4</u>
--	---	---------------------------------------	--

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.

Alyson M. Mount
Senior Vice President and Chief Accounting Officer
639 Loyola Avenue
New Orleans, Louisiana 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.

Arkansas - October 2, 1926

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.

None

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

Arkansas - Electric Utility Service
Missouri - Electric Utility Service
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) Yes...Enter the date when such independent accountant was initially engaged:
(2) No

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2017/Q4</u>
--	---	---------------------------------------	--

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, 2017, Entergy Corporation owned 46,980,196 shares of the Respondent's common stock which represented 100% of the voting rights.

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	System Fuels, Inc.			(1)
2	Entergy Arkansas Restoration Funding, LLC		100%	
3	Arkansas Power & Light Company, LLC		90%	
4	The Arkklahoma Corporation		47.6%	(2)
5				
6				
7				
8				
9				
10	(1) Entergy Arkansas, Entergy Louisiana			
11	Properties, LLC, Entergy Mississippi, and			
12	Entergy Utility Group own 35%, 33%, 19%, and			
13	13%, respectively of all the common stock			
14	of System Fuels, Inc., a subsidiary			
15	incorporated in Louisiana that until the first			
16	quarter of 2011 implemented and/or			
17	maintained certain programs to procure,			
18	deliver, and store fuel supplies for those			
19	companies.			
20				
21	(2) For the purpose of co-ownership of a			
22	transmission line with Oklahoma Gas & Electric			
23	Company.			
24				
25				
26				
27				

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer		
2	of Entergy Arkansas	Richard C. Riley	341,723
3			
4	Chief Executive Officer & Chairman of the Board		
5	of Entergy Corporation	Leo P. Denault	
6			
7	Executive VP & Chief Financial Officer	Andrew S. Marsh	
8			
9	Executive VP & Chief Operating Officer		
10	of Entergy Corporation	Paul D. Hinnenkamp	
11			
12	Executive VP & General Counsel	Marcus V. Brown	
13			
14	Group President Utility Operations (1)	Theodore H. Bunting, Jr.	
15			
16	Group President Utility Operations (2)	Roderick K. West	
17			
18	Executive VP of Entergy Corporation (3)	Roderick K. West	
19			
20	Exec. VP & Chief Nuclear Officer of Entergy Arkansas	A. Christopher Bakken, III	
21			
22	Executive VP & Chief Administrative Officer		
23	of Entergy Corporation	Donald W. Vinci	
24			
25	Senior VP & Chief Accounting Officer	Alyson M. Mount	
26			
27	Senior VP of Human Resources of Entergy Corporation	Andrea Coughlin Rowley	
28			
29	Senior VP & General Tax Counsel	Joseph T. Henderson	
30			
31	(1) ceased effective June 2017		
32	(2) effective July 2017		
33	(3) ceased effective July 2017		
34			
35	*Officers whose salaries are not		
36	presented were compensated by		
37	other System companies and not		
38	by Entergy Arkansas		
39			
40			
41			
42			
43			
44			

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Richard C. Riley - President and Chief Executive Officer	
2	of Entergy Arkansas	425 W. Capitol Avenue, Little Rock, AR 72201
3		
4	Theodore H. Bunting, Jr. - Group President	
5	Utility Operations (1)	639 Loyola Avenue, New Orleans, LA 70113
6		
7	Roderick K. West - Group President Utility Operations (2)	639 Loyola Avenue, New Orleans, LA 70113
8		
9	Andrew S. Marsh - Executive VP & Chief Financial Officer	639 Loyola Avenue, New Orleans, LA 70113
10		
11	Paul D. Hinnenkamp - Exec. VP & Chief Operating Officer	
12	of Entergy Corporation	639 Loyola Avenue, New Orleans, LA 70113
13		
14		
15		
16	(1) ceased effective June 2017	
17	(2) effective July 2017	
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? Yes
 No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Arkansas Electric Cooperative Corporation (AECC)	
2	Wholesale Distribution Agreement RS No 82 (WDS)	
3	Baseline Tariff	Docket No. ER14-133
4		
5	Rate Schedule No. 705: Entergy Operating Companies	
6	Unit Power Sales/Designated Power Purchase	
7	Tariff (UPS/DPPT or MSS-4 Replacement Tariff)	
8	Baseline Tariff	Docket No. ER13-1508
9	Amended Tariff	Docket No. ER16-2199
10		
11		
12	MISO-FERC Electric Tariff	
13	Fifth Revised Volume 1	Docket No. ER13-948
14	MISO-FERC Electric Tariff	Docket No. ER14-649
15	MISO-FERC Electric Tariff	Docket No. ER15-358
16	MISO-FERC Electric Tariff	Docket No. ER15-1436
17	MISO-FERC Electric Tariff	Docket No. ER16-227
18	MISO-FERC Electric Tariff	Docket No. ER16-1322
19	MISO-FERC Electric Tariff	Docket No. ER17-215
20	MISO-FERC Electric Tariff	Docket No. ER17-1549
21	MISO-FERC Electric Tariff	Docket No. ER17-1777
22	MISO-FERC Electric Tariff	Docket No. ER17-2579
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4
FOOTNOTE DATA			

Schedule Page: 106 Line No.: 12 Column: a

Informational filing for the following footnote applies to all lines of page 106 and additional 106 pages.

Midcontinent Independent System Operator, Inc. (MISO)

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

Yes
 No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20160615-5146	06/15/2016	ER14-133	2016 Biennial EA	RS No. 82
2				Informational Wholesale	
3				Distribution Rate (WDS)	
4				Formula Update re	
5				Distribution Agreement	
6				between EAI and AECC	
7					
8	20170315-5220	03/15/2017	ER17-1262	EAI Annual	
9				Informational MISC	
10				Attach. O Transmission	
11				Formula Rate Update	
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 1061 Line No.: 1 Column: d

Filed biennially. There was no filing in 2017. The next filing is in 2018.

Schedule Page: 1061 Line No.: 8 Column: d

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 (MISO) Open Access Transmission, Entergy 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 2016 update was filed on March 15, 2017 in Docket No. ER17-1262. This Informational Filing is not a rate filing. It shows the development of the Entergy Operating Companies' annual transmission revenue requirements for June 1, 2016 through May 31, 2017 through the application of data for Calendar Year 2015 under the Attachment O MISO Tariff.

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).	Schedule	Column	Line No
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
6				and 50
7	204,206	Electric Plant in Service		(g) 4,86-59
8	206	Electric Plant in Service		(g) 97
9	219	Accumulated Provision for Depreciation		(c) 1
10	227	Materials and Supplies		(c) 1-2
11	227	Materials and Supplies		(c) 12,16
12	234	Accumulated Deferred Income Taxes (Account 190)		(c) 2
13	262	Taxes Accrued, Prepaid and Charged During Year		(d) 17
14	262	Taxes Accrued, Prepaid and Charged During Year		(d) 2,9
15	262	Taxes Accrued, Prepaid and Charged During Year		(d) 3,4,10
16	266	Accumulated Deferred Investment Tax Credits		(f) 8
17	275	Accumulated Deferred Income Taxes (Account 282)		(k) 2
18	277	Accumulated Deferred Income Taxes (Account 283)		(k) 3
19	320-321	Electric Operations and Maintenance Expense		(b) 4,6-11,15-19,24,26-32
20				35-39,44-49,53-57,62,
21				64-66 and 69-72
22	320-321	Electric Operations and Maintenance Expense		(b) 93,107
23	323	Electric Operations and Maintenance Expense		(b) 181-184 and 186-193
24	323	Electric Operations and Maintenance Expense		(b) 185
25	336	Depreciation Expense		(f) 2-7
26	336	Depreciation Expense		(f) 10
27	110-111	Comparative Balance Sheet		(c) 48,52,54
28	110-111	Comparative Balance Sheet		(c) 57
29	114	Statement of Income		(c) 14
30	206-207	Electric Plant in Service		(g) 58
31	206-207	Electric Plant in Service		(g) 75
32	206-207	Electric Plant in Service		(g) 75
33	206-207	Electric Plant in Service		(g) 75
34	219	Accumulated Provision for Depreciation (Acc 108)		(c) 26
35	219	Accumulated Provision for Depreciation (Acc 108)		(c) 26
36	219	Accumulated Provision for Depreciation (Acc 108)		(c) 28
37	262-263	Taxes Accrued, Prepaid and Charged During Year		(d) 3,4,10
38	262-263	Taxes Accrued, Prepaid and Charged During Year		(d), (i) 14,18
39	274-277	Accumulated Deferred Income Taxes		(k) 9
40	274-277	Accumulated Deferred Income Taxes		(k) 19
41	300	Electric Operating Revenues		(b) 19
42	300	Electric Operating Revenues		(b) 19
43	322	Electric Operation and Maintenance Expenses		(b) 156
44				

INFORMATION ON FORMULA RATES (continued)
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).	Schedule	Column	Line No
1	323	Electric Operation and Maintenance Expenses		(b) 197
2	336	Depreciation and Amortization of Electric Plant		(f) 8
3	336	Depreciation and Amortization of Electric Plant		(f) 8
4	336	Depreciation and Amortization of Electric Plant		(f) 2-6
5	354	Distribution of Salaries and Wages		(b) 20
6	354	Distribution of Salaries and Wages		(b) 21
7	354	Distribution of Salaries and Wages		(b) 23
8	354	Distribution of Salaries and Wages		(b) 24-25
9	355	Distribution of Salaries and Wages		(b) 96
10				
11		Footnotes explaining differences are attached.		
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 1062 Line No.: 1 Column: a

Line No.	Page No(s) .	Schedule	Column	Line No.
All	All	Footnotes are not applicable for the Informational Update under MISO's Attachment O Transmission Formula Rate Update		
1	111	Comparative Balance Sheet Prepayments used in RS No.705, Unit Power Sales/Designated Power Purchase Tariff (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 in the annual AECC Wholesale Distribution Formula Rate (WDS) 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	(c)	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)	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	(g)	8-14, 18-24, 27-34, 37-43 and 50
FERC FORM NO. 1 (ED. 12-87)		Page 450.1		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		//	2017/Q4
FOOTNOTE DATA			
		transformers and associated transmission equipment related to the Designated Generating Unit, at the last day of the previous month	
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	(g) 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	(g) 97
9	219	Accumulated Provision for Depreciation (APD) 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	(c) 1
10	227	Materials and Supplies Costs used in UPS/DPPT differs 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 differs 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 differs 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	(c) 2
13	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differs from Form 1 amounts because the formula rate only reflects the ad valorem taxes related to the Designated Generating Unit	(d) 17

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

14	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differs from Form 1 amounts because the formula rates calculate State and Federal income taxes using the incremental statutory rate	(d)	2, 9
15	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differs from Form 1 amounts because the formula rate allocates Payroll Taxes based on a Labor Ratio	(d)	3, 4, 10
16	266	Accumulated Deferred Investment Tax Credits Costs used in UPS/DPPT differs 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
17	275	Accumulated Deferred Income Taxes (Account 282) Costs used in UPS/DPPT differs 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	(k)	2
18	277	Accumulated Deferred Income Taxes (Account 283) Costs used in UPS/DPPT differs 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	(k)	3
19 20 21	320-321	Electric Operations and Maintenance Expense Costs used in UPS/DPPT differs 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
22	320-321	Electric Operations and Maintenance Expense Costs used in UPS/DPPT differs 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	(b)	93, 107
23	323	Electric Operations and Maintenance Expenses Costs used in UPS/DPPT differs from	(b)	181-184 and 186-193

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		//	2017/Q4
FOOTNOTE DATA			
		Form 1 amounts because the formula rate allocates A&G costs using a Labor Ratio	
24	323	Electric Operations and Maintenance Expense Costs used in UPS/DPPT differs from Form 1 amounts because the formula rate only reflects the Insurance Expense related to the Designated Generating Unit	(b) 185
25	336	Depreciation Expense Costs used in UPS/DPPT differs 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	(f) 2-7
26	336	Depreciation Expense Costs used in UPS/DPPT differs from Form 1 amounts because the formula rate only reflects an allocation of the monthly General Plant Depreciation Expense using a Labor Ratio	(f) 10
27	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
28	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
29	114	Statement of Income Taxes Other than Income used in the WDS differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(c) 14
30	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
31	206-207	Electric Plant in Service Distribution Plant in Service in the WDS differs from Form 1 amounts	(g) 75
FERC FORM NO. 1 (ED. 12-87)			
Page 450.4			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		//	2017/Q4
FOOTNOTE DATA			
32	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
33	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
34	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)	(c) 26
35	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	(c) 26
36	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 used in wholesale-related filings	(c) 28
37	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) 3, 4, 10
38	262-263	Taxes Accrued, Prepaid and Charged During Year Non Income Taxes in the WDS differs from Form 1 amounts because the formula rate includes Non-Income Tax	(d), (i) 14, 18
39	274-277	Accumulated Deferred Income Taxes	(k) 9
FERC FORM NO. 1 (ED. 12-87)			
Page 450.5			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		//	2017/Q4
FOOTNOTE DATA			
		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	
40	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
41	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
42	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
43	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
44	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
1	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
2	336	Depreciation and Amortization of Electric Plant Total General Depreciation Expense in the WDS differs from Form 1 amounts because the formula rate allocates a portion of the general depreciation expense to Wholesale	(f) 8

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
--	---	---------------------------------------	----------------------------------

FOOTNOTE DATA

3	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)	2-6
4	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
5	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
6	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
7	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
8	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, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report / /	Year/Period of Report End of <u>2017/Q4</u>
--	---	-----------------------	--

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 Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None
2. None
3. None
4. None
5. None
6. See Entergy Arkansas's 2017 FERC Form 1 Notes to Financial Statements, Notes 4, 5, 6, and 8.
7. None
8. Fossil operating and clerical employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Unions 647, 750, and 1703. The Company and the Union agreed to a contract effective October 1, 2015 through October 1, 2018. Effective October 1, 2017, the wage increase was 2.25%.

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, 2015 through October 1, 2018. Effective October 1, 2017, the wage increase was 2.25%.

Effective April 1, 2017, executive and senior management, middle management, professionals, and non-represented operating, maintenance, and support staff pay increases averaged approximately 2.5%.

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, 2015 through March 1, 2018. Effective March 1, 2017, the wage increase was 2.25%.

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, 2016 through February 28, 2019. Effective March 1, 2017, the wage increase was 2.25%.
9. See Entergy Arkansas's 2017 FERC Form 1 Notes to Financial Statements, Notes 2, 8, and 14.
10. None
11. Not applicable
12. See Entergy Arkansas's 2017 FERC Form 1 Notes to Financial Statements.
13. See Entergy Arkansas's 2017 FERC Form 1 pages 104 and 105 for Officer and Director changes that occurred in 2017.
14. Not applicable

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)	200-201	11,186,592,311	10,605,531,491
3	Construction Work in Progress (107)	200-201	293,919,423	321,435,342
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,480,511,734	10,926,966,833
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,681,668,737	4,602,908,137
6	Net Utility Plant (Enter Total of line 4 less 5)		6,798,842,997	6,324,058,696
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	63,325,891	59,186,176
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		192,950,953	229,909,367
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	-21,068,448	-18,256,483
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		277,345,292	307,352,026
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,076,188,289	6,631,410,722
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		460,715	488,569
19	(Less) Accum. Prov. for Depr. and Amort. (122)		108,077	130,072
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	301,642	282,315
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		947,262,920	841,853,894
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		947,917,200	842,494,706
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		540	565,757
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		2,675,290	72,903
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		108,848,314	101,058,886
41	Other Accounts Receivable (143)		65,209,169	58,153,033
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,063,111	1,211,102
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		38,764,950	35,285,549
45	Fuel Stock (151)	227	25,428,706	28,412,584
46	Fuel Stock Expenses Undistributed (152)	227	3,888,517	4,346,544
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	174,173,366	163,429,463
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	40,927	566

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	18,679,357	19,170,388
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,904,835	7,236,183
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	758
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		105,119,557	100,193,082
62	Miscellaneous Current and Accrued Assets (174)		59,092,840	82,356,891
63	Derivative Instrument Assets (175)		2,972,851	5,391,792
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		609,736,108	604,463,277
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		33,482,548	33,554,598
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,467,976,627	1,479,735,751
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		303,318	398,598
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	13,083,539	13,635,476
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		24,349,058	27,623,456
82	Accumulated Deferred Income Taxes (190)	234	310,918,865	219,563,378
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,850,113,955	1,774,511,257
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,483,955,552	9,852,879,962

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 5 Column: c

Includes removal cost accrual of \$176,926,141.

Schedule Page: 110 Line No.: 5 Column: d

Includes removal cost accrual of \$128,527,380.

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)	250-251	469,802	469,802
3	Preferred Stock Issued (204)	250-251	31,350,000	31,350,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		3,461,114	3,461,114
7	Other Paid-In Capital (208-211)	253	786,782,648	786,782,648
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	49,710	49,710
11	Retained Earnings (215, 215.1, 216)	118-119	1,592,144,260	1,468,851,388
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-6,123,904	-6,247,195
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		2,408,034,210	2,284,618,047
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,560,000,000	2,340,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	230,477,180	283,610,448
22	Unamortized Premium on Long-Term Debt (225)		8,361,771	4,312,468
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,043,010	3,313,635
24	Total Long-Term Debt (lines 18 through 23)		2,795,795,941	2,624,609,281
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		89,192,552	50,501,247
27	Accumulated Provision for Property Insurance (228.1)		28,215,800	13,122,088
28	Accumulated Provision for Injuries and Damages (228.2)		4,858,837	3,751,054
29	Accumulated Provision for Pensions and Benefits (228.3)		-16,870,529	15,299,943
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,654,001	1,809,000
31	Accumulated Provision for Rate Refunds (229)		1,962,644	1,532,224
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		981,212,852	924,352,874
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,090,226,157	1,010,368,430
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		212,546,588	185,153,184
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		379,458,675	255,781,047
41	Customer Deposits (235)		97,687,272	97,512,363
42	Taxes Accrued (236)	262-263	91,792,881	88,626,961
43	Interest Accrued (237)		17,873,613	15,961,268
44	Dividends Declared (238)		356,931	356,931
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		14,268,793	13,942,129
48	Miscellaneous Current and Accrued Liabilities (242)		6,528,502	14,665,640
49	Obligations Under Capital Leases-Current (243)		103,729,900	106,338,649
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		924,243,155	778,338,172
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,401,660	10,506,612
57	Accumulated Deferred Investment Tax Credits (255)	266-267	34,103,811	35,305,095
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	423,535,563	456,193,566
60	Other Regulatory Liabilities (254)	278	1,349,414,564	328,693,604
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,258,442,835	1,861,826,372
64	Accum. Deferred Income Taxes-Other (283)		197,757,656	462,420,783
65	Total Deferred Credits (lines 56 through 64)		3,265,656,089	3,154,946,032
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,483,955,552	9,852,879,962

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

5. Do not report fourth quarter data in columns (e) and (f)
6. 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,125,292,762	2,071,677,934		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,128,100,259	1,057,908,287		
5	Maintenance Expenses (402)	320-323	290,687,271	257,326,174		
6	Depreciation Expense (403)	336-337	255,610,976	244,208,127		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,141,881	2,141,881		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	17,716,239	16,307,307		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	2,506,968	2,294,965		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		28,922,815	31,015,915		
13	(Less) Regulatory Credits (407.4)		57,577,243	36,564,189		
14	Taxes Other Than Income Taxes (408.1)	262-263	103,412,810	92,963,625		
15	Income Taxes - Federal (409.1)	262-263	-37,859,199	-29,321,177		
16	- Other (409.1)	262-263	5,689,792	19,837		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,575,459,507	1,808,016,909		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,469,674,557	1,686,657,041		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,225,968	-1,226,204		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		37	39		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		56,859,984	53,610,277		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,900,771,498	1,812,044,654		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		224,521,264	259,633,280		

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		224,521,264	259,633,280		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		806,131	299,506		
34	(Less) Expenses of Nonutility Operations (417.1)		713,014	384,677		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	127,140	-111,180		
37	Interest and Dividend Income (419)		35,837,807	19,067,847		
38	Allowance for Other Funds Used During Construction (419.1)		19,210,726	17,754,353		
39	Miscellaneous Nonoperating Income (421)		3,543,647	2,818,796		
40	Gain on Disposition of Property (421.1)		29,500	87,300		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		58,841,937	39,531,945		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		952,961	2,620,231		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,412,703	1,403,379		
46	Life Insurance (426.2)					
47	Penalties (426.3)		2,577	54,970		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,030,254	2,243,194		
49	Other Deductions (426.5)		6,298,551	4,668,778		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,697,046	10,990,552		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263		83		
53	Income Taxes-Federal (409.2)	262-263	17,335,594	14,011,978		
54	Income Taxes-Other (409.2)	262-263	3,444,445	2,836,440		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		20,780,039	16,848,501		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		27,364,852	11,692,892		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		104,204,731	101,338,675		
63	Amort. of Debt Disc. and Expense (428)		2,504,500	2,395,472		
64	Amortization of Loss on Reaquired Debt (428.1)		3,274,398	3,251,700		
65	(Less) Amort. of Premium on Debt-Credit (429)		808,297	252,532		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		552,754	110,092		
68	Other Interest Expense (431)		11,230,708	6,838,574		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,916,561	9,567,998		
70	Net Interest Charges (Total of lines 62 thru 69)		112,042,233	104,113,983		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		139,843,883	167,212,189		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		139,843,883	167,212,189		

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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		1,468,851,388	1,308,828,821
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4		214		(2,032,823)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			(2,032,823)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		139,716,743	167,323,369
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24		238	-1,427,720	(5,269,823)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,427,720	(5,269,823)
30	Dividends Declared-Common Stock (Account 438)			
31		238	-15,000,000	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-15,000,000	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		3,849	1,844
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,592,144,260	1,468,851,388
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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)
41				
42				
43				
44				
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)		1,592,144,260	1,468,851,388
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-6,247,195	(6,134,171)
50	Equity in Earnings for Year (Credit) (Account 418.1)		127,140	(111,180)
51	(Less) Dividends Received (Debit)		3,849	1,844
52				
53	Balance-End of Year (Total lines 49 thru 52)		-6,123,904	(6,247,195)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 24 Column: c

For the Year Ended December 31, 2017

\$100 Preferred Stock:	
4.32% Series, \$4.32 per share	\$302,400
4.72% Series, \$4.72 per share	441,320
4.56% Series, \$4.56 per share	342,000
4.56% Series, (1965 Series) \$4.56 per share	<u>342,000</u>
Total Preferred Stock Dividends	<u>\$1,427,720</u> =====

Schedule Page: 118 Line No.: 24 Column: d

For the Year Ended December 31, 2016

\$100 Preferred Stock:	
4.32% Series, \$4.32 per share	\$302,400
4.72% Series, \$4.72 per share	441,320
4.56% Series, \$4.56 per share	342,000
4.56% Series, (1965 Series) \$4.56 per share	342,000
6.08% Series, \$6.08 per share	428,978
\$25 Preferred Stock:	
6.45% Series	<u>3,413,125</u>
Total Preferred Stock Dividends	<u>\$5,269,823</u> =====

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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	139,843,883	167,212,189
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	334,836,048	318,562,557
5	Amortization of Debt Discount and Premium on Debt	5,778,898	5,647,172
6			
7			
8	Deferred Income Taxes (Net)	105,784,950	121,359,868
9	Investment Tax Credit Adjustment (Net)	-1,225,968	-1,226,204
10	Net (Increase) Decrease in Receivables	-23,399,431	-29,289,533
11	Net (Increase) Decrease in Inventory	-6,810,967	17,191,957
12	Net (Increase) Decrease in Allowances Inventory	-40,361	56,606
13	Net Increase (Decrease) in Payables and Accrued Expenses	41,244,345	248,664,789
14	Net (Increase) Decrease in Other Regulatory Assets	11,759,124	-126,678,850
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,020,720,960	22,670,574
16	(Less) Allowance for Other Funds Used During Construction	19,210,726	17,754,353
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Deferred tax rate change recognized as regulatory liability/asset	-1,047,836,701	
20	Other Working Capital	19,379,533	-41,582,532
21	Other	-135,590,904	-122,094,268
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	445,232,683	562,739,972
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-735,816,804	-666,288,674
27	Gross Additions to Nuclear Fuel	-151,423,787	-102,049,889
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-19,210,726	-17,754,353
31	Other (provide details in footnote): Payment for Purchase of Plant		-237,323,460
32	Decommissioning Trust Funds	-12,704,326	-15,703,185
33	Proceeds from Sale of Nuclear Fuel	179,380,124	93,284,768
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-701,354,067	-910,326,087
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-193,629	-103,250
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Insurance Proceeds		10,404,470
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55	Other		5,937,651
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-701,547,696	-894,087,216
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	222,695,775	777,562,673
62	Preferred Stock		
63	Common Stock		200,000,000
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Changes in Money Pool Payable - Net	114,904,952	-1,510,177
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	337,600,727	976,052,496
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-54,715,871	-560,015,219
74	Preferred Stock		-85,283,000
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79	Other	-8,104,953	-1,158,020
80	Dividends on Preferred Stock	-1,427,720	-6,631,198
81	Dividends on Common Stock	-15,000,000	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	258,352,183	322,965,059
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,037,170	-8,382,185
87			
88	Cash and Cash Equivalents at Beginning of Period	638,660	9,020,845
89			
90	Cash and Cash Equivalents at End of period	2,675,830	638,660

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report / /	Year/Period of Report End of <u>2017/Q4</u>
--	---	-----------------------	--

NOTES TO FINANCIAL STATEMENTS

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

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

A. CASH FLOW STATEMENT, ADDITIONAL INFORMATION:

Cash and Cash Equivalents at December 31, 2017

Cash (Account 131)	\$ 540
Working Fund (Account 135)	<u>2,675,290</u>
Total Cash and Cash Equivalents	<u>\$2,675,830</u>

SUPPLEMENTAL DISCLOSURE OF CASH FLOW STATEMENT (in 000s)

Cash paid (received) during the period for:

Interest – net of amt capitalized	\$113,876
Income Taxes	(\$8,662)

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 2016 data for the statement of 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, Inc. classifies certain items 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, 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 its majority owned subsidiary, Entergy Arkansas Restoration Funding, LLC, whereas the investment in the company is presented in the Form 1 using the equity method. The significant difference that results from this is the inclusion on Entergy Arkansas's GAAP-basis balance sheet of storm cost regulatory assets that are the property of and securitization bonds that are the obligations of the subsidiary.

C. 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, 2017. 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, Inc., Entergy Louisiana, LLC,

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Mississippi, Inc., 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, with a small amount of natural gas distribution.

"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 generally accepted accounting principles 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.

Revenues and Fuel Costs

Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy Texas generate, transmit, and distribute electric power primarily to retail customers in Arkansas, Louisiana, Mississippi, and Texas, respectively. Entergy Louisiana also distributes natural gas to retail customers in and around Baton Rouge, Louisiana. Entergy New Orleans sells both electric power and natural gas to retail customers in the City of New Orleans, including Algiers. Prior to October 1, 2015, Entergy Louisiana was the electric power supplier for Algiers. The Entergy Wholesale Commodities segment derives almost all of its revenue from sales of electric power generated by plants owned by subsidiaries in that segment.

Entergy recognizes revenue from electric power and natural gas sales when power or gas is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, Entergy's Utility operating companies accrue an estimate of the revenues for energy delivered since the latest billings. The Utility operating companies calculate the estimate based upon several factors including billings through the last billing cycle in a month, actual generation in the month, historical line loss factors, and prices in effect in Entergy's Utility operating companies' various jurisdictions. Changes are made to the inputs in the estimate as needed to reflect changes in billing practices. Each month the estimated unbilled revenue amounts are recorded as revenue and unbilled accounts receivable, and the prior month's estimate is reversed. Therefore, changes in price and volume differences resulting from factors such as weather affect the calculation of unbilled revenues from one period to the next, and may result in variability in reported revenues from one period to the next as prior estimates are reversed and new estimates recorded.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

For sales under rates implemented subject to refund, Entergy reduces revenue by accruing estimated amounts for probable refunds when Entergy believes it is probable that revenues will be refunded to customers based upon the status of the rate proceeding.

Entergy's Utility operating companies' rate schedules include either fuel adjustment clauses or fixed fuel factors, which allow either current recovery in billings to customers or deferral of fuel costs until the costs are billed to customers. Where the fuel component of revenues is billed based on a pre-determined fuel cost (fixed fuel factor), the fuel factor remains in effect until changed as part of a general rate case, fuel reconciliation, or fixed fuel factor filing. System Energy's operating revenues are intended to recover from Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans operating expenses and capital costs attributable to Grand Gulf. The capital costs are computed by allowing a return on System Energy's common equity funds allocable to its net investment in Grand Gulf, plus System Energy's effective interest cost for its debt allocable to its investment in Grand Gulf.

Accounting for MISO transactions

Entergy is a member of MISO, a regional transmission organization that maintains functional control over the combined transmission systems of its members and manages one of the largest energy markets in the U.S. In the MISO market, Entergy offers its generation and bids its load into the market on an hourly basis. MISO settles these hourly offers and bids based on locational marginal prices, which is pricing for energy at a given location based on a market clearing price that takes into account physical limitations on the transmission system, generation, and demand throughout the MISO region. MISO evaluates the market participants' energy offers and demand bids to economically and reliably dispatch the entire MISO system. Entergy nets purchases and sales within the MISO market on an hourly basis and reports in operating revenues when in a net selling position for an hour period and in operating expenses when in a net purchasing position for an hour period.

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. Substantially all of the Registrant Subsidiaries' plant is subject to mortgage liens.

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	Entergy	Entergy	Entergy New	Entergy	System
----------------	----------------	----------------	------------------------	----------------	---------------

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

	<u>Arkansas</u>	<u>Louisiana</u>	<u>Mississippi</u>	<u>Orleans</u>	<u>Texas</u>	<u>Energy</u>
2017	2.5%	2.3%	3.1%	3.5%	2.6%	2.8%
2016	2.5%	2.3%	3.1%	3.4%	2.5%	2.8%
2015	2.6%	2.3%	3.2%	3.0%	2.6%	2.8%

As of December 31, 2017, construction expenditures included in accounts payable are \$58.8 million for Entergy Arkansas, \$160.4 million for Entergy Louisiana, \$17.1 million for Entergy Mississippi, \$2.5 million for Entergy New Orleans, \$32.8 million for Entergy Texas, and \$33.9 million for System Energy. As of December 31, 2016, construction expenditures included in accounts payable are \$40.9 million for Entergy Arkansas, \$114.8 million for Entergy Louisiana, \$11.5 million for Entergy Mississippi, \$2.3 million for Entergy New Orleans, \$9.3 million for Entergy Texas, and \$6.2 million for System Energy.

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, 2017, the subsidiaries' investment and accumulated depreciation in each of these generating stations were as follows:

<u>Generating Stations</u>	<u>Fuel Type</u>	<u>Total Megawatt Capability (a)</u>	<u>Ownership</u>	<u>Investment</u>	<u>Accumulated Depreciation</u>	
(In Millions)						
Utility business:						
Entergy Arkansas -						
Independence	Unit 1	Coal	836	31.50%	\$140	\$103
Independence	Common Facilities	Coal		15.75%	\$34	\$27
White Bluff	Units 1 and 2	Coal	1,636	57.00%	\$531	\$364
Ouachita (b)	Common Facilities	Gas		66.67%	\$172	\$150
Union (c)	Units 1 and 2 Common Facilities	Gas		50.00%	\$1	\$—
Union (c)	Common Facilities	Gas		25.00%	\$28	\$3
Entergy Louisiana -						
Roy S. Nelson	Unit 6	Coal	550	40.25%	\$280	\$194
Roy S. Nelson	Unit 6 Common Facilities	Coal		25.79%	\$15	\$6
Big Cajun 2	Unit 3	Coal	574	24.15%	\$150	\$117

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Big Cajun 2	Unit 3 Common Facilities	Coal		8.05%	\$5	\$2
Ouachita (b)	Common Facilities	Gas		33.33%	\$90	\$75
Acadia	Common Facilities	Gas		50.00%	\$20	\$—
Union (c)	Common Facilities	Gas		50.00%	\$55	\$3
Entergy Mississippi -						
Independence	Units 1 and 2 and Common Facilities	Coal	1,678	25.00%	\$266	\$156
Entergy New Orleans -						
Union (c)	Units 1 and 2 Common Facilities	Gas		50.00%	\$1	\$—
Union (c)	Common Facilities	Gas		25.00%	\$28	\$3
Entergy Texas -						
Roy S. Nelson	Unit 6	Coal	550	29.75%	\$200	\$114
Roy S. Nelson	Unit 6 Common Facilities	Coal		14.16%	\$6	\$3
Big Cajun 2	Unit 3	Coal	574	17.85%	\$113	\$76
Big Cajun 2	Unit 3 Common Facilities	Coal		5.95%	\$3	\$1
System Energy -						
Grand Gulf (d)	Unit 1	Nuclear	1,414	90.00%	\$4,916	\$3,175

- (a) “Total Megawatt Capability” is the dependable load carrying capability as demonstrated under actual operating conditions based on the primary fuel (assuming no curtailments) that each station was designed to utilize.
- (b) 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.
- (c) 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.
- (d) Includes a leasehold interest held by System Energy. System Energy’s Grand Gulf lease obligations are discussed in Note 10 to the financial statements.

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)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 Entergy's intercompany income tax allocation agreements. 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. See the "**Other Tax Matters - Tax Cuts and Jobs Act**" section in Note 3 to the financial statements for discussion of the effects of the enactment of the Tax Cuts and Jobs Act, in December 2017.

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 enterprises whose rates meet three criteria specified in accounting standards. The Utility operating companies and System Energy have rates that (i) are approved by a body (its regulator) empowered to set rates that bind customers; (ii) are cost-based; and (iii) can 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. Because the Utility operating companies and System Energy meet these criteria, each of them capitalizes costs, which would otherwise be charged to expense, if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. Such capitalized costs are reflected as regulatory assets in the accompanying financial statements. When an enterprise concludes that recovery of a regulatory asset is no longer probable, the regulatory asset must be removed from the entity's balance sheet.

An enterprise that ceases to meet the three criteria for all or part of its operations should report that event in its financial statements. In general, the enterprise no longer meeting the criteria should eliminate from its balance sheet all regulatory assets and liabilities related to the applicable operations. Additionally, if it is determined that a regulated enterprise is no longer recovering all of its costs, it is possible that an impairment may exist that could require further write-offs of plant assets.

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 returned 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.

Securitization Recovery Trust Accounts

The funds that Entergy Arkansas, Entergy Louisiana, Entergy New Orleans, and Entergy Texas hold in their securitization recovery trust accounts are not classified as cash and cash equivalents or restricted cash and cash equivalents because of their nature, uses, and restrictions. These funds are classified as part of other current assets and other investments, depending on the timeframe within which the Registrant Subsidiary expects to use the funds.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects Entergy's best estimate of losses on the accounts receivable balances. The allowance is based on accounts receivable agings, historical experience, and other currently available evidence. Utility operating company customer accounts receivable are written off consistent with approved regulatory requirements.

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. For the 30% interest in River Bend formerly owned by Cajun, Entergy Louisiana records an offsetting amount in other deferred credits for the excess trust earnings not currently expected to be needed to decommission the plant. The assessment of whether an investment in a debt security has

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

suffered an other-than-temporary impairment is based on whether Entergy has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. Further, if Entergy does not expect to recover the entire amortized cost basis of the debt security, an other-than-temporary impairment is considered to have occurred and it is measured by the present value of cash flows expected to be collected less the amortized cost basis (credit loss). The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment is based on a number of factors including, first, whether Entergy has the ability and intent to hold the investment to recover its value, the duration and severity of any losses, and, then, whether it is expected that the investment will recover its value within a reasonable period of time. Effective January 1, 2018 with the adoption of ASU 2016-01, unrealized gains and losses on investments in equity securities held by the nuclear decommissioning trust funds will be recorded in earnings as they occur rather than in other comprehensive income. In accordance with the regulatory treatment of the decommissioning trust funds of the Registrant Subsidiaries, an offsetting amount of unrealized gains/losses will continue to be recorded 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.

Equity Method Investments

Entergy owns investments that are accounted for under the equity method of accounting because Entergy's ownership level results in significant influence, but not control, over the investee and its operations. Entergy records its share of the investee's comprehensive earnings and losses in income and as an increase or decrease to the investment account. Any cash distributions are charged against the investment account. Entergy discontinues the recognition of losses on equity investments when its share of losses equals or exceeds its carrying amount for an investee plus any advances made or commitments to provide additional financial support.

Derivative Financial Instruments and Commodity Derivatives

The accounting standards for derivative instruments and hedging activities 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 or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction. 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.

For other contracts for commodities in which Entergy is hedging the variability of cash flows related to a

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

variable-rate asset, liability, or forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. To qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods when the underlying transactions actually occur. The ineffective portions of all hedges are recognized in current-period earnings. Changes in the fair value of derivative instruments that are not designated as cash flow hedges are recorded in current-period earnings on a mark-to-market basis.

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 held by regulated businesses may be 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 held in all of its business segments 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 (except that portion allocable to the deregulated operations of Entergy Louisiana) are included in regulatory

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

assets and 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.

Presentation of Preferred Stock without Sinking Fund

Accounting standards regarding non-controlling interests and the classification and measurement of redeemable securities require the classification of preferred securities between liabilities and shareholders' equity on the balance sheet if the holders of those securities have protective rights that allow them to gain control of the board of directors in certain circumstances. These rights would have the effect of giving the holders the ability to potentially redeem their securities, even if the likelihood of occurrence of these circumstances is considered remote. The Entergy Arkansas, Entergy Mississippi, and, prior to December 1, 2017, Entergy New Orleans articles of incorporation provide, generally, that the holders of each company's preferred securities may elect a majority of the respective company's board of directors if dividends are not paid for a year, until such time as the dividends in arrears are paid. Therefore, Entergy Arkansas, Entergy Mississippi, and Entergy New Orleans present their preferred securities outstanding between liabilities and shareholders' equity on the balance sheet. In November 2017, Entergy New Orleans redeemed its outstanding preferred securities as part of a multi-step process to undertake an internal restructuring. See Note 2 to the financial statements for a discussion of Entergy New Orleans's internal restructuring.

The outstanding preferred securities of Entergy Arkansas, Entergy Mississippi, and Entergy New Orleans, and Entergy Utility Holding Company (a Utility subsidiary) and Entergy Finance Holding (an Entergy Wholesale Commodities subsidiary), whose preferred holders also have protective rights, are similarly presented between liabilities and equity on Entergy's consolidated balance sheets. The preferred dividends or distributions paid by all subsidiaries are reflected for all periods presented outside of consolidated net income.

NOTE 2. RATE AND REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent probable future revenues associated with costs that Entergy expects to recover 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 Entergy expects 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

presented on FERC Form 1 page 278.

Regulatory activity regarding the Tax Cuts and Jobs Act

See the “**Other Tax Matters - Tax Cuts and Jobs Act**” section in Note 3 to the financial statements for discussion of the effects of the enactment of the Tax Cuts and Jobs Act, in December 2017, including its effects on Entergy’s and the Registrant Subsidiaries’ regulatory asset/liability for income taxes.

After enactment of the Tax Cuts and Jobs Act the APSC issued an order that applies to investor-owned utilities in Arkansas, including Entergy Arkansas. The order requests information regarding certain effects of the Tax Cuts and Jobs Act and requires the utilities to begin, effective January 1, 2018, to record regulatory liabilities to record the effects of the Act, subject to review by the APSC, although the order acknowledges that the exact amount of tax savings and rate reductions cannot be determined at this time. Entergy Arkansas requested clarification or, in the alternative, rehearing regarding the requirement to record a regulatory liability, and also responded to the request for information. In its request for clarification Entergy Arkansas sought clarification that the amount of any regulatory liability would be determined only after the utilities are heard and present evidence on the issue, as this otherwise would be arbitrary and could implicate single-issue and retroactive ratemaking. The APSC has not responded to the request for clarification. In its response to the APSC’s request for information Entergy Arkansas states that its formula rate plan rider already provides the means for customers to realize the benefits of the Act, except for the return of unprotected excess accumulated deferred income taxes. Entergy Arkansas’s next formula rate plan filing is scheduled for July 2018. Entergy Arkansas intends to return unprotected excess accumulated deferred income taxes as expeditiously as possible, subject to a subsequent request to be made by Entergy Arkansas and approval by the APSC.

The Registrant Subsidiaries will continue to work with their respective regulators to determine the appropriate path forward in each jurisdiction regarding the effects of the Act.

Fuel and purchased power cost recovery

Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas 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 deferred fuel costs as of December 31, 2017 and 2016 that Entergy expects to recover (or return to customers) through fuel mechanisms, subject to subsequent regulatory review.

	<u>2017</u>	<u>2016</u>
	(In Millions)	
Entergy Arkansas (a)	\$130.4	\$163.6
Entergy Louisiana (b)	\$96.7	\$119.9
Entergy Mississippi	\$32.4	\$7.0

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy New Orleans (b)	(\$3.7)	\$8.9
Entergy Texas	(\$67.3)	(\$54.5)

- (a) Includes \$67.1 million in 2017 and \$66.9 million in 2016 of fuel and purchased power 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.
- (b) Includes \$168.1 million in each year for Entergy Louisiana and \$4.1 million in each year for Entergy New Orleans of 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.

Entergy Arkansas

Production Cost Allocation Rider

The APSC approved a production cost allocation rider for recovery from customers of the retail portion of the costs allocated to Entergy Arkansas as a result of the System Agreement proceedings, which are discussed in the “**System Agreement Cost Equalization Proceedings**” section below. These costs cause an increase in Entergy Arkansas’s deferred fuel cost balance because Entergy Arkansas pays the costs over seven months but collects the costs from customers over twelve months.

In May 2014, Entergy Arkansas filed its annual redetermination of the production cost allocation rider to recover the \$3 million unrecovered retail balance as of December 31, 2013 and the \$67.8 million System Agreement bandwidth remedy payment made in May 2014 as a result of the compliance filing pursuant to the FERC’s February 2014 orders related to the bandwidth payments/receipts for the June - December 2005 period. In January 2015 the APSC issued an order approving Entergy Arkansas’s request for recovery of the \$3 million under-recovered amount based on the true-up of the production cost allocation rider and the \$67.8 million May 2014 System Agreement bandwidth remedy payment subject to refund with interest, with recovery of these payments concluding with the last billing cycle in December 2015. The APSC also found that Entergy Arkansas is entitled to carrying charges pursuant to the current terms of the production cost allocation rider. Entergy Arkansas made its compliance filing pursuant to the order in January 2015 and the APSC issued its approval order, also in January 2015. The redetermined rate went into effect with the first billing cycle of February 2015.

In May 2015, Entergy Arkansas filed its annual redetermination of the production cost allocation rider, which included a \$38 million payment made by Entergy Arkansas as a result of the FERC’s February 2014 order related to the comprehensive bandwidth recalculation for calendar year 2006, 2007, and 2008 production costs. The redetermined rate for the 2015 production cost allocation rider update was added to the redetermined rate from the 2014 production cost allocation rider update and the combined rate was effective with the first billing cycle of July 2015. This combined rate was effective through December 2015. The collection of the remainder of the redetermined rate for the 2015 production cost allocation rider update continued through June 2016.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

In May 2016, Entergy Arkansas filed its annual redetermination pursuant to the production cost allocation rider, which reflected recovery of the production cost allocation rider true-up adjustment of the 2014 and 2015 unrecovered retail balance in the amount of \$1.9 million. Additionally, the redetermined rates reflected the recovery of a \$1.9 million System Agreement bandwidth remedy payment resulting from a compliance filing pursuant to the FERC’s December 2015 order related to test year 2009 production costs. The rates for the 2016 production cost allocation rider update became effective with the first billing cycle of July 2016, and the rates were effective through June 2017.

In May 2017, Entergy Arkansas filed its annual redetermination pursuant to the production cost allocation rider, which reflected a credit amount of \$0.3 million resulting from a compliance filing pursuant to the FERC’s September 2016 order. Additionally, the redetermined rate reflected recovery of the production cost allocation rider true-up adjustment of the 2016 unrecovered retail balance in the amount of \$0.3 million. Because of the small effect of the 2017 production cost allocation rider update, Entergy Arkansas proposed to reduce the effective period of the update to one month, July 2017. After the one month collection period, rates were set to zero for all rate classes for the period August 2017 through June 2018.

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 redetermination of its energy cost rate that was subsequently filed in March 2014. In that motion, Entergy Arkansas requested that the APSC authorize Entergy Arkansas to exclude \$65.9 million of deferred fuel and purchased energy costs incurred in 2013 from the redetermination of its 2014 energy cost rate. The \$65.9 million is an estimate of the incremental fuel and replacement energy costs that Entergy Arkansas incurred 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 is available regarding various claims associated with the ANO stator incident. The APSC approved Entergy Arkansas’s request in February 2014. In July 2017, Entergy Arkansas filed for a change in rates pursuant to its formula rate plan rider. In that docket, the APSC approved a settlement agreement agreed upon by the parties, including a provision that requires Entergy Arkansas to initiate a docket 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 previously noted, subject to certain timelines and conditions set forth in the settlement agreement. See the **“ANO Damage, Outage, and NRC Reviews”** section in Note 8 to the financial statements for further discussion of the ANO stator incident.

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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.

Retail Rate Proceedings

Filings with the APSC (Entergy Arkansas)

Retail Rates

2015 Base Rate Filing

In April 2015, Entergy Arkansas filed with the APSC for a general change in rates, charges, and tariffs. The filing notified the APSC of Entergy Arkansas's intent to implement a forward test year formula rate plan pursuant to Arkansas legislation passed in 2015, and requested a retail rate increase of \$268.4 million, with a net increase in revenue of \$167 million. The filing requested a 10.2% return on common equity. In September 2015 the APSC staff and intervenors filed direct testimony, with the APSC staff recommending a revenue requirement of \$217.9 million and a 9.65% return on common equity. In December 2015, Entergy Arkansas, the APSC staff, and certain of the intervenors in the rate case filed with the APSC a joint motion for approval of a settlement of the case that proposed a retail rate increase of approximately \$225 million with a net increase in revenue of approximately \$133 million; an authorized return on common equity of 9.75%; and a formula rate plan tariff that provides a +/- 50 basis point band around the 9.75% allowed return on common equity. A significant portion of the rate increase is related to Entergy Arkansas's acquisition in March 2016 of Union Power Station Power Block 2 for a base purchase price of \$237 million. The settlement agreement also provided for amortization over a 10-year period of \$7.7 million of previously-incurred costs related to ANO post-Fukushima compliance and \$9.9 million of previously-incurred costs related to ANO flood barrier compliance. A settlement hearing was held in January 2016. In February 2016 the APSC approved the settlement with one exception that reduced the retail rate increase proposed in the settlement by \$5 million. The settling parties agreed to the APSC modifications in February 2016. The new rates were effective February 24, 2016 and began billing with the first billing cycle of April 2016. In March 2016, Entergy Arkansas made a compliance filing regarding the new rates that included an interim base rate adjustment surcharge, effective with the first billing cycle of April 2016, to recover the incremental revenue requirement for the period February 24, 2016 through March 31, 2016. The interim base rate adjustment surcharge was designed to recover a total of \$21.1 million over the nine-month period from April 2016 through December 2016.

2016 Formula Rate Plan Filing

In July 2016, Entergy Arkansas filed with the APSC its 2016 formula rate plan filing showing Entergy

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Arkansas's projected earned return on common equity for the twelve months ended December 31, 2017 test period to be below the formula rate plan bandwidth. The filing requested a \$67.7 million revenue requirement increase to achieve Entergy Arkansas's target earned return on common equity of 9.75%. In October 2016, Entergy Arkansas filed with the APSC revised formula rate plan attachments with an updated request for a \$54.4 million revenue requirement increase based on acceptance of certain adjustments and recommendations made by the APSC staff and other intervenors, as well as three additional adjustments identified as appropriate by Entergy Arkansas. In November 2016 a hearing was held and the APSC issued an order directing the parties to brief certain issues. In December 2016 the APSC approved the settlement agreement and the \$54.4 million revenue requirement increase with approximately \$25 million of the \$54.4 million revenue requirement subject to possible future adjustment and refund to customers with interest. The APSC requested supplemental information for some of Entergy Arkansas's requested nuclear expenditures. In December 2016 the APSC approved Entergy Arkansas's formula rate plan compliance tariff, and the rates became effective with the first billing cycle of January 2017. In April 2017, Entergy Arkansas filed a motion consented to by all parties requesting that it be permitted to submit the supplemental information requested by the APSC in conjunction with its 2017 formula rate plan filing, which was subsequently made in July 2017 and is discussed below. In May 2017 the APSC approved the joint motion and proposal to review Entergy Arkansas's supplemental information on a concurrent schedule with the 2017 formula rate plan filing. In October 2017, Entergy Arkansas and the parties to the proceeding filed a joint motion to approve a unanimous settlement agreement resolving all issues in the docket and providing for recovery of the 2017 and 2018 nuclear costs. In December 2017 the APSC approved the settlement agreement and recovery of the 2017 and 2018 nuclear costs.

2017 Formula Rate Plan Filing

In July 2017, Entergy Arkansas filed with the APSC its 2017 formula rate plan filing showing Entergy Arkansas's projected earned return on common equity for the twelve months ended December 31, 2018 test period to be below the formula rate plan bandwidth. The filing projected a \$129.7 million revenue requirement increase to achieve Entergy Arkansas's target earned return on common equity of 9.75%. Entergy Arkansas's formula rate plan is subject to a four percent annual revenue constraint and the projected annual revenue requirement increase exceeded the four percent, resulting in a proposed increase for the 2017 formula rate plan of \$70.9 million. In October 2017, Entergy Arkansas filed with the APSC revised formula rate plan attachments that projected a \$126.2 million revenue requirement increase based on acceptance of certain adjustments and recommendations made by the APSC staff and other intervenors. The revised formula rate plan filing included a proposed \$71.1 million revenue requirement increase based on a revision to the four percent constraint calculation. In October 2017, Entergy Arkansas and the parties to the proceeding filed a joint motion to approve a unanimous settlement agreement resolving all issues in the docket and providing for recovery of the 2017 and 2018 nuclear costs. In December 2017 the APSC approved the settlement agreement and the \$71.1 million revenue requirement increase, as well as Entergy Arkansas's formula rate plan compliance tariff, and the rates became effective with the first billing cycle of January 2018.

Internal Restructuring

In November 2017, Entergy Arkansas filed an application with the APSC seeking authorization to undertake a

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

restructuring that would result in the transfer of substantially all of the assets and operations of Entergy Arkansas to a new entity, which would ultimately be owned by an existing Entergy subsidiary holding company. The restructuring is subject to regulatory review and approval by the APSC, the FERC, and the NRC. Entergy Arkansas also filed a notice with the Missouri Public Service Commission in December 2017 out of an abundance of caution, although Entergy Arkansas does not serve any retail customers in Missouri. If the APSC approves the restructuring by September 1, 2018, and the restructuring closes on or before December 1, 2018, Entergy Arkansas proposed in its application to credit retail customers \$66 million over six years, beginning in 2019. In February 2018, Entergy Arkansas filed supplemental testimony reducing the proposed retail customer credits to \$39.6 million over six years. If the APSC, the FERC, and the NRC approvals are obtained, Entergy Arkansas expects the restructuring will be consummated on or before December 1, 2018.

It is currently contemplated that Entergy Arkansas would undertake a multi-step restructuring, which would include the following:

- Entergy Arkansas would redeem its outstanding preferred stock at the aggregate redemption price of approximately \$32.7 million, which includes call premiums, plus accumulated and unpaid dividends, if any.
- Entergy Arkansas would convert from an Arkansas corporation to a Texas corporation.
- Under the Texas Business Organizations Code (TXBOC), Entergy Arkansas will allocate substantially all of its assets to a new subsidiary, Entergy Arkansas Power, LLC, a Texas limited liability company (Entergy Arkansas Power), and Entergy Arkansas Power will assume substantially all of the liabilities of Entergy Arkansas, in a transaction regarded as a merger under the TXBOC. Entergy Arkansas will remain in existence and hold the membership interests in Entergy Arkansas Power.
- Entergy Arkansas will contribute the membership interests in Entergy Arkansas Power to an affiliate (Entergy Utility Holding Company, LLC, a Texas limited liability company and subsidiary of Entergy Corporation). As a result of the contribution, Entergy Arkansas Power will be a wholly-owned subsidiary of Entergy Utility Holding Company, LLC.
- Entergy Arkansas will change its name to Entergy Utility Property, Inc., and Entergy Arkansas Power will then change its name to Entergy Arkansas, LLC.

Upon the completion of the restructuring, Entergy Arkansas, LLC will hold substantially all of the assets, and will have assumed substantially all of the liabilities, of Entergy Arkansas. Entergy Arkansas may modify or supplement the steps to be taken to effectuate the restructuring.

Advanced Metering Infrastructure (AMI) Filings

Entergy Arkansas

In September 2016, Entergy Arkansas filed an application seeking a finding from the APSC that Entergy Arkansas's deployment of AMI is in the public interest. Entergy Arkansas proposed to replace existing meters with advanced meters that enable two-way data communication; design and build a secure and reliable network to support such communications; and implement support systems. AMI is intended to serve as the foundation of Entergy Arkansas's

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

modernized power grid. The filing included an estimate of implementation costs for AMI of \$208 million. The filing identified a number of quantified and unquantified benefits, and Entergy Arkansas provided a cost benefit analysis showing that its AMI deployment is expected to produce a nominal net benefit to customers of \$406 million. Entergy Arkansas also sought to continue to include in rate base the remaining book value of existing meters, which was approximately \$57 million at December 31, 2015, that will be retired as part of the AMI deployment and also to depreciate those assets using current depreciation rates. Entergy Arkansas proposed a 15-year depreciable life for the new advanced meters, the three-year deployment of which is expected to begin in 2019. Deployment of the communications network is expected to begin in 2018. Entergy Arkansas proposed to include the AMI deployment costs and the quantified benefits in future formula rate plan filings, and the 2018 costs were approved in the 2017 formula rate plan filing. In June 2017 the APSC staff and Arkansas Attorney General filed direct testimony. The APSC staff generally supported Entergy Arkansas's AMI deployment conditioned on various recommendations. The Arkansas Attorney General's consultant primarily recommended denial of Entergy Arkansas's application but alternatively suggested recommendations in the event the APSC approves Entergy Arkansas's proposal. Entergy Arkansas filed rebuttal testimony in June 2017, substantially accepting the APSC staff's recommendations. In August 2017, Entergy Arkansas and the parties to the proceeding filed a joint motion to approve a unanimous settlement agreement. In October 2017 the APSC issued an order finding that Entergy Arkansas's AMI deployment is in the public interest and approving the settlement agreement subject to a minor modification. Entergy Arkansas expects to recover the undepreciated balance of its existing meters through a regulatory asset to be amortized over 15 years. Entergy Arkansas has begun discussions with the other parties to implement the items in the settlement agreement including pre-pay and time of use programs.

System Agreement Cost Equalization Proceedings

Prior to its final termination in 2016, the Utility operating companies historically engaged in the coordinated planning, construction, and operation of generating and bulk transmission facilities under the terms of the System Agreement. Entergy Arkansas terminated its participation in the System Agreement in December 2013. Entergy Mississippi terminated its participation in the System Agreement in November 2015. The System Agreement terminated with respect to its remaining participants in August 2016.

Although the System Agreement has terminated, certain of the Utility operating companies' retail regulators continue to pursue litigation involving the System Agreement at the FERC and in federal courts. The proceedings include challenges to the allocation of costs as defined by the System Agreement and other matters.

In June 2005 the FERC issued a decision in System Agreement litigation that had been commenced by the LPSC, and essentially affirmed its decision in a December 2005 order on rehearing. The decision included, among other things:

- The FERC's conclusion that the System Agreement no longer roughly equalizes total production costs among the Utility operating companies.
- In order to reach rough production cost equalization, the FERC imposed a bandwidth remedy by which each company's total annual production costs will have to be within +/- 11% of Entergy System average total annual

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

production costs.

- In calculating the production costs for this purpose under the FERC's order, output from the Vidalia hydroelectric power plant will not reflect the actual Vidalia price for the year but is priced at that year's average price paid by Entergy Louisiana for the exchange of electric energy under Service Schedule MSS-3 of the System Agreement, thereby reducing the amount of Vidalia costs reflected in the comparison of the Utility operating companies' total production costs.
- The remedy ordered by the FERC in 2005 required no refunds and became effective based on calendar year 2006 production costs and the first reallocation payments were made in 2007.

The FERC's decision reallocated total production costs of the Utility operating companies whose relative total production costs expressed as a percentage of Entergy System average production costs are outside an upper or lower bandwidth. This was accomplished by payments from Utility operating companies whose production costs were more than 11% below Entergy System average production costs to Utility operating companies whose production costs were more than the Entergy System average production cost, with payments going first to those Utility operating companies whose total production costs were farthest above the Entergy System average.

The LPSC, APSC, MPSC, and the Arkansas Electric Energy Consumers appealed the FERC's December 2005 decision to the United States Court of Appeals for the D.C. Circuit. Entergy and the City of New Orleans intervened in the various appeals. The D.C. Circuit issued its decision in April 2008. The D.C. Circuit concluded that the FERC's orders had failed to adequately explain both its conclusion that it was prohibited from ordering refunds for the 20-month period from September 13, 2001 - May 2, 2003 and its determination to implement the bandwidth remedy commencing on January 1, 2006, rather than June 1, 2005. The D.C. Circuit remanded the case to the FERC for further proceedings on those two issues.

In October 2011 the FERC issued an order addressing the D.C. Circuit remand on the two issues. On the first issue, the FERC concluded that it did have the authority to order refunds, but decided that it would exercise its equitable discretion and not require refunds for the 20-month period from September 13, 2001 - May 2, 2003. Because the ruling on refunds relied on findings in the interruptible load proceeding, which is discussed in a separate section below, the FERC concluded that this refund ruling will be held in abeyance pending the outcome of the rehearing requests in the interruptible load proceeding. On the second issue, the FERC reversed its prior decision and ordered that the prospective bandwidth remedy begin on June 1, 2005 (the date of its initial order in the proceeding) rather than January 1, 2006, as it had previously ordered. Pursuant to the October 2011 order, Entergy was required to calculate bandwidth payments for the period June - December 2005 utilizing the bandwidth formula tariff prescribed by the FERC that was filed in a December 2006 compliance filing and accepted by the FERC in an April 2007 order.

In March 2015, in light of a December 2014 decision by the D.C. Circuit in the interruptible load proceeding, Entergy filed with the FERC a motion to establish a briefing schedule on refund issues and an initial brief addressing refund issues. The initial brief argued that the FERC, in response to the D.C. Circuit decision, should clarify its policy on refunds and find that refunds are not required in this proceeding. In October 2015 the FERC issued three orders related to the commencement of the remedy on June 1, 2005 and the inclusion of interest for the period June 1, 2005 through

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

December 31, 2005. Specifically, the FERC rejected Entergy's request for rehearing of its decision to include interest for the seven-month period. The FERC also rejected Entergy's request for rehearing of the order rejecting the compliance filing with regard to the issue of interest. Finally, the FERC set for hearing and settlement procedures the 2014 compliance filing that included the bandwidth calculation for the seven months June 1, 2005 through December 31, 2005. In setting the compliance filing for hearing, the FERC rejected the APSC's protest that Entergy Arkansas should not be subject to the filing because Entergy Arkansas would be making the payments during a period following its exit from the System Agreement. In January 2018 the D.C.Circuit affirmed the FERC decision that Entergy Arkansas was subject to the filing.

In December 2011, Entergy filed with the FERC its compliance filing that provides the payments and receipts among the Utility operating companies pursuant to the FERC's October 2011 order. The APSC, the LPSC, the PUCT, and other parties intervened in the December 2011 compliance filing proceeding, and the APSC and the LPSC also filed protests. The filing shows the following payments/receipts among the Utility operating companies:

	Payments (Receipts)
	(In Millions)
Entergy Arkansas	\$156
Entergy Louisiana	(\$75)
Entergy Mississippi	(\$33)
Entergy New Orleans	(\$5)
Entergy Texas	(\$43)

Entergy Arkansas made its payment in January 2012. In February 2012, Entergy Arkansas filed for an interim adjustment to its production cost allocation rider requesting that the \$156 million be collected from customers over the 22-month period from March 2012 through December 2013. In March 2012 the APSC issued an order stating that the payment can be recovered from retail customers through the production cost allocation rider, subject to refund. The LPSC and the APSC requested rehearing of the FERC's October 2011 order.

In February 2014 the FERC issued a rehearing order addressing its October 2011 order. The FERC denied the LPSC's request for rehearing on the issues of whether the bandwidth remedy should be made effective earlier than June 1, 2005, and whether refunds should be ordered for the 20-month refund effective period. The FERC granted the LPSC's rehearing request on the issue of interest on the bandwidth payments/receipts for the June - December 2005 period, requiring that interest be accrued from June 1, 2006 until the date those bandwidth payments/receipts are made. Also in February 2014 the FERC issued an order rejecting the December 2011 compliance filing that calculated the bandwidth payments/receipts for the June - December 2005 period. The FERC order required a new compliance filing that calculates the bandwidth payments/receipts for the June - December 2005 period based on monthly data for the seven individual months including interest pursuant to the February 2014 rehearing order. Entergy sought rehearing of the February 2014 order with respect to the FERC's determinations regarding interest. In April 2014 the LPSC filed a

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

petition for review of the FERC's October 2011 and February 2014 orders with the U.S. Court of Appeals for the D.C. Circuit. In August 2017 the D.C. Circuit issued a decision addressing the LPSC's appeal of the FERC's October 2011 and February 2014 orders. On the issue of the FERC's implementation of the prospective remedy as of June 2005 and whether the bandwidth remedy should be extended for an additional 17 months in years 2004-2005, the D.C. Circuit affirmed the FERC's implementation of the remedy and denied the LPSC's appeal. On the issue of whether the operating companies should be required to issue refunds for the 20-month period from September 2001 to May 2003, the D.C. Circuit granted the FERC's request for agency reconsideration and remanded that issue back to the FERC for further proceedings as requested by all parties to the appeal.

In April and May 2014, Entergy filed with the FERC an updated compliance filing that provides the payments and receipts among the Utility operating companies pursuant to the FERC's February 2014 orders. The filing shows the following net payments and receipts, including interest, among the Utility operating companies:

	Payments (Receipts)
	(In Millions)
Entergy Arkansas	\$68
Entergy Louisiana	(\$10)
Entergy Mississippi	(\$11)
Entergy New Orleans	\$2
Entergy Texas	(\$49)

These payments were made in May 2014. The LPSC, City Council, and APSC filed protests.

The hearing on the bandwidth calculation for the seven months June 1, 2005 through December 31, 2005 occurred in July 2016. The presiding judge issued an initial decision in November 2016. In the initial decision, the presiding judge agreed with the Utility operating companies' position that: (1) interest on the bandwidth payments for the 2005 test period should be accrued from June 1, 2006 until the date that the bandwidth payments for that calculation are paid, which is consistent with how the Utility operating companies performed the calculation; and (2) a portion of Entergy Louisiana's 2001-vintage Louisiana state net operating loss accumulated deferred income tax that results from the Vidalia tax deduction should be excluded from the 2005 test period bandwidth calculation. Various participants filed briefs on exceptions and/or briefs opposing exceptions related to the initial decision, including the LPSC, the APSC, the FERC trial staff, and Entergy Services. The initial decision is pending before the FERC.

Rough Production Cost Equalization Rates

Each May from 2007 through 2016 Entergy filed with the FERC the rates to implement the FERC's orders in the System Agreement proceeding. These filings showed the following payments/receipts among the Utility operating companies were necessary to achieve rough production cost equalization as defined by the FERC's orders:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Payments (Receipts)

	2007	2008	2009	2010	2011	2012	2013	2014
	(In Millions)							
Entergy Arkansas	\$252	\$252	\$390	\$41	\$77	\$41	\$—	\$—
Entergy Louisiana	(\$211)	(\$160)	(\$247)	(\$22)	(\$12)	(\$41)	\$—	\$—
Entergy Mississippi	(\$41)	(\$20)	(\$24)	(\$19)	(\$40)	\$—	\$—	\$—
Entergy New Orleans	\$—	(\$7)	\$—	\$—	(\$25)	\$—	(\$15)	(\$15)
Entergy Texas	(\$30)	(\$65)	(\$119)	\$—	\$—	\$—	\$15	\$15

The Utility operating companies recorded accounts payable or accounts receivable to reflect the rough production cost equalization payments and receipts required to implement the FERC's remedy. When accounts payable were recorded, a corresponding regulatory asset was recorded for the right to collect the payments from customers. When accounts receivable were recorded, a corresponding regulatory liability was recorded for the obligations to pass the receipts on to customers. No payments were required in 2016 or 2015 to implement the FERC's remedy based on calendar year 2015 production costs and 2014 production costs, respectively. The System Agreement terminated in August 2016.

The APSC approved a production cost allocation rider for recovery from customers of the retail portion of the costs allocated to Entergy Arkansas. Entergy Texas recovered its 2013 rough production cost equalization payment over three years beginning April 2014. Entergy Texas included its 2014 rough production cost equalization payment as a component of an interim fuel refund made in 2014. Management believes that any changes in the allocation of production costs resulting from the FERC's decision and related retail proceedings should result in similar rate changes for retail customers, subject to specific circumstances that have caused trapped costs.

The following rough production cost equalization rate proceedings are still ongoing.

2010 Rate Filing Based on Calendar Year 2009 Production Costs

In May 2010, Entergy filed with the FERC the 2010 rates in accordance with the FERC's orders in the System Agreement proceeding, and supplemented the filing in September 2010. Several parties intervened in the proceeding at the FERC, including the LPSC and the City Council, which also filed protests. In July 2010 the FERC accepted Entergy's proposed rates for filing, effective June 1, 2010, subject to refund. After an abeyance of the proceeding schedule, a hearing was held in March 2014 and in December 2015 the FERC issued an order. Among other things, the December 2015 order directed Entergy to submit a compliance filing. In January 2016 the LPSC, the APSC, and Entergy filed requests for rehearing of the FERC's December 2015 order. In February 2016, Entergy submitted the compliance filing ordered in the December 2015 order. The result of the true-up payments and receipts for the recalculation of production costs resulted in the following payments/receipts among the Utility operating companies:

**Payments
(Receipts)**

(In Millions)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Arkansas	\$2
Entergy Louisiana	\$6
Entergy Mississippi	(\$4)
Entergy New Orleans	(\$1)
Entergy Texas	(\$3)

In September 2016 the FERC accepted the February 2016 compliance filing subject to a further compliance filing made in November 2016. The further compliance filing was required as a result of an order issued in September 2016 ruling on the January 2016 rehearing requests filed by the LPSC, the APSC, and Entergy. In the order addressing the rehearing requests, the FERC granted the LPSC's rehearing request and directed that interest be calculated on the payment/receipt amounts. The FERC also granted the APSC's and Entergy's rehearing request and ordered the removal of both securitized asset accumulated deferred income taxes and contra-securitization accumulated deferred income taxes from the calculation. In November 2016, Entergy submitted its compliance filing in response to the FERC's order on rehearing. The compliance filing included a revised refund calculation of the true-up payments and receipts based on 2009 test year data and interest calculations. The LPSC protested the interest calculations. In November 2017 the FERC issued an order rejecting the November 2016 compliance filing. The FERC determined that the payments detailed in the November 2016 compliance filing did not include adequate interest for the payments from Entergy Arkansas to Entergy Louisiana because it did not include interest on the principal portion of the payment that was made in February 2016. In December 2017, Entergy recalculated the interest pursuant to the November 2017 order. As a result of the recalculations, Entergy Arkansas owed very minor payments to Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans.

2011 Rate Filing Based on Calendar Year 2010 Production Costs

In May 2011, Entergy filed with the FERC the 2011 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. In July 2011 the FERC accepted Entergy's proposed rates for filing, effective June 1, 2011, subject to refund. After an abeyance of the proceeding schedule, in December 2014 the FERC consolidated the 2011 rate filing with the 2012, 2013, and 2014 rate filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

2012 Rate Filing Based on Calendar Year 2011 Production Costs

In May 2012, Entergy filed with the FERC the 2012 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. In August 2012 the FERC accepted Entergy's proposed rates for filing, effective June 2012, subject to refund. After an abeyance of the proceeding schedule, in December 2014 the FERC consolidated the 2012 rate filing with the 2011, 2013, and 2014 rate filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

2013 Rate Filing Based on Calendar Year 2012 Production Costs

In May 2013, Entergy filed with the FERC the 2013 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. The City Council intervened and filed comments related to including the outcome of a related FERC proceeding in the 2013 cost equalization calculation. In August 2013 the FERC issued an order accepting the 2013 rates, effective June 1, 2013, subject to refund. After an abeyance of the proceeding schedule, in December 2014 the FERC consolidated the 2013 rate filing with the 2011, 2012, and 2014 rate filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

2014 Rate Filing Based on Calendar Year 2013 Production Costs

In May 2014, Entergy filed with the FERC the 2014 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. The City Council intervened and filed comments. In December 2014 the FERC issued an order accepting the 2014 rates, effective June 1, 2014, subject to refund, set the proceeding for hearing procedures, and consolidated the 2014 rate filing with the 2011, 2012, and 2013 rate filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

Consolidated 2011, 2012, 2013, and 2014 Rate Filing Proceedings

As discussed above, in December 2014 the FERC consolidated the 2011, 2012, 2013, and 2014 rate filings for settlement and hearing procedures. In May 2015, Entergy filed direct testimony in the consolidated rate filings and the LPSC filed direct testimony concerning its complaint proceeding that is consolidated with the rate filings, challenging certain components of the pending bandwidth calculations for prior years. Hearings occurred in November 2015, and the ALJ issued an initial decision in July 2016. In the initial decision, the ALJ generally agreed with Entergy's bandwidth calculations with one exception on the accounting related to the Waterford 3 sale/leaseback. Briefs were filed in September 2016 and the proceeding is pending.

Utility Operating Company Termination of System Agreement Participation

Entergy Arkansas and Entergy Mississippi ceased participating in the System Agreement effective December 18, 2013 and November 7, 2015, respectively. Entergy Louisiana, Entergy New Orleans, and Entergy Texas terminated participation in the System Agreement on August 31, 2016, which resulted in the termination of the System Agreement in its entirety pursuant to a settlement agreement approved by the FERC in December 2015.

In December 2013 the FERC set one issue for hearing involving whether and how the benefits associated with settlement with Union Pacific regarding certain coal delivery issues should be allocated among Entergy Arkansas and the other Utility operating companies post-termination of the System Agreement. In December 2014 a FERC ALJ issued an initial decision finding that Entergy Arkansas would realize benefits after December 18, 2013 from the 2008 settlement

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

agreement between Entergy Services, Entergy Arkansas, and Union Pacific, related to certain coal delivery issues. The ALJ further found that all of the Utility operating companies should share in those benefits pursuant to a methodology proposed by the MPSC. The Utility operating companies and other parties to the proceeding filed briefs on exceptions and/or briefs opposing exceptions with the FERC challenging various aspects of the December 2014 initial decision. In March 2016 the FERC issued an opinion affirming the December 2014 initial decision with regard to the determination that there were benefits related to the Union Pacific settlement, which were realized post-Entergy Arkansas's December 2013 withdrawal from the System Agreement, that should be shared with the other Utility operating companies utilizing the methodology proposed by the MPSC and trued-up to actual coal volumes purchased. In May 2016, Entergy made a compliance filing that provided the calculation of Union Pacific settlement benefits utilizing the methodology adopted by the initial decision, trued-up for the actual volumes of coal purchased. The payments were made in May 2016. In August 2016 the FERC issued an order accepting Entergy's compliance filing. Also in August 2016 the APSC filed a petition for review of the FERC's March 2016 and August 2016 orders with the U.S. Court of Appeals for the D.C. Circuit. Oral argument before the D.C. Circuit was held on the APSC's petition in January 2018 and a decision is pending.

In connection with the System Agreement termination settlement agreement, the purchase power agreements, referred to as the jurisdictional separation plan PPAs, between Entergy Texas and Entergy Gulf States Louisiana that were put in place for certain legacy gas units at the time of Entergy Gulf States's separation into Entergy Texas and Entergy Gulf States Louisiana terminated effective with the System Agreement termination. Similarly, the purchase power agreement between Entergy Gulf States Louisiana and Entergy Texas for the Calcasieu unit also terminated. In March 2016, Entergy Services filed with the FERC the notices of termination. The jurisdictional separation plan PPAs were the means by which Entergy Texas received payment for its receivable associated with Entergy Louisiana's Spindletop gas storage facility regulatory asset. As a result of the System Agreement termination settlement agreement, effective with the termination date, Entergy Texas no longer receives payments from Entergy Louisiana related to the Spindletop storage facility, which resulted in a write-off recorded in 2015 by Entergy Texas of \$23.5 million (\$15.3 million net-of-tax). Upon termination of the System Agreement, other purchase power agreements entered into under Service Schedule MSS-4 of the System Agreement were replaced with updated agreements under a FERC-jurisdictional tariff effective September 1, 2016.

Interruptible Load Proceeding

In April 2007 the U.S. Court of Appeals for the D.C. Circuit issued its opinion in the LPSC's appeal of the FERC's March 2004 and April 2005 orders related to the treatment under the System Agreement of the Utility operating companies' interruptible loads. In its opinion the D.C. Circuit concluded that the FERC: (1) acted arbitrarily and capriciously by allowing the Utility operating companies to phase-in the effects of the elimination of the interruptible load over a 12-month period of time; (2) failed to adequately explain why refunds could not be ordered under Section 206(c) of the Federal Power Act; and (3) exercised appropriately its discretion to defer addressing the cost of sulfur dioxide allowances until a later time. The D.C. Circuit remanded the matter to the FERC for a more considered determination on the issue of refunds. The FERC issued its order on remand in September 2007, in which it directed Entergy to make a compliance filing removing all interruptible load from the computation of peak load responsibility commencing April 1, 2004 and to issue any necessary refunds to reflect this change. In addition, the order directed the

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Utility operating companies to make refunds for the period May 1995 through July 1996. In November 2007 the Utility operating companies filed a refund report describing the refunds to be issued pursuant to the FERC's orders. The LPSC filed a protest to the refund report in December 2007, and the Utility operating companies filed an answer to the protest in January 2008. The refunds were made in October 2008 by the Utility operating companies that owed refunds to the Utility operating companies that were due refunds under the decision. The APSC and the Utility operating companies appealed the FERC decisions to the D.C. Circuit.

Following the filing of petitioners' initial briefs, the FERC filed a motion requesting the D.C. Circuit hold the appeal of the FERC's decisions ordering refunds in the interruptible load proceeding in abeyance and remand the record to the FERC. The D.C. Circuit granted the FERC's unopposed motion in June 2009. In December 2009 the FERC established a paper hearing to determine whether the FERC had the authority and, if so, whether it would be appropriate to order refunds resulting from changes in the treatment of interruptible load in the allocation of capacity costs by the Utility operating companies. In August 2010 the FERC issued an order stating that it has the authority and refunds are appropriate. The APSC, the MPSC, and Entergy requested rehearing of the FERC's decision. In June 2011 the FERC issued an order granting rehearing in part and denying rehearing in part, in which the FERC determined to invoke its discretion to deny refunds. The FERC held that in this case where "the Entergy system as a whole collected the proper level of revenue, but, as was later established, incorrectly allocated peak load responsibility among the various Entergy operating companies....the Commission will apply here our usual practice in such cases, invoking our equitable discretion to not order refunds, notwithstanding our authority to do so." The LPSC has requested rehearing of the FERC's June 2011 decision. In July 2011 the refunds made in the fourth quarter 2009 described above were reversed. In October 2011 the FERC issued an "Order Establishing Paper Hearing" inviting parties that oppose refunds to file briefs within 30 days addressing the LPSC's argument that FERC precedent supports refunds under the circumstances present in this proceeding. Parties that favor refunds were then invited to file reply briefs within 21 days of the date that the initial briefs were due.

In September 2010 the FERC had issued an order setting the refund report filed in the proceeding in November 2007 for hearing and settlement judge procedures. In May 2011, Entergy filed a settlement agreement that resolved all issues relating to the refund report set for hearing. In June 2011 the settlement judge certified the settlement as uncontested. The settlement agreement was approved by the FERC in September 2016.

Prior to the FERC's June 2011 order on rehearing, Entergy Arkansas filed an application in November 2010 with the APSC for recovery of the refund that it paid. The APSC denied Entergy Arkansas's application, and also denied Entergy Arkansas's petition for rehearing. If the FERC were to order Entergy Arkansas to pay refunds on rehearing in the interruptible load proceeding the APSC's decision would trap FERC-approved costs at Entergy Arkansas with no regulatory-approved mechanism to recover them. In August 2011, Entergy Arkansas filed a complaint in the United States District Court for the Eastern District of Arkansas asking for a declaratory judgment that the rejection of Entergy Arkansas's application by the APSC is preempted by the Federal Power Act. The APSC filed a motion to dismiss the complaint. In April 2012 the United States district court dismissed Entergy Arkansas's complaint without prejudice stating that Entergy Arkansas's claim is not ripe for adjudication and that Entergy Arkansas did not have standing to bring suit at this time.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

In March 2013 the FERC issued an order denying the LPSC’s request for rehearing of the FERC’s June 2011 order wherein the FERC concluded it would exercise its discretion and not order refunds in the interruptible load proceeding. Based on its review of the LPSC’s request for rehearing and the briefs filed as part of the paper hearing established in October 2011, the FERC affirmed its earlier ruling and declined to order refunds under the circumstances of the case. In May 2013 the LPSC filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit seeking review of FERC prior orders in the interruptible load proceeding that concluded that the FERC would exercise its discretion and not order refunds in the proceeding. Oral argument was held on the appeal in the D.C. Circuit in September 2014. In December 2014 the D.C. Circuit issued an order on the LPSC’s appeal and remanded the case back to the FERC. The D.C. Circuit rejected the LPSC’s argument that there is a presumption in favor of refunds, but it held that the FERC had not adequately explained its decision to deny refunds and directed the FERC “to consider the relevant factors and weigh them against one another.” In March 2015, Entergy filed with the FERC a motion to establish a briefing schedule on remand and an initial brief on remand to address the December 2014 decision by the D.C. Circuit. The initial brief on remand argued that the FERC, in response to the D.C. Circuit decision, should clarify its policy on refunds and find that refunds are not required in the interruptible load proceeding.

In April 2016 the FERC issued an order on remand that addressed the December 2014 decision by the D.C. Circuit in the interruptible load proceeding. The order on remand affirmed the FERC’s denial of refunds for the 15-month refund effective period. The FERC explained and clarified its policies regarding refunds and concluded that the evidence in the record demonstrated that the relevant equitable factors favored not requiring refunds in this case. The FERC also noted that, under Section 206(c) of the Federal Power Act, in a Section 206 proceeding involving two or more electric utility companies of a registered holding company system, the FERC may order refunds only if it determines the refunds would not cause the registered holding company to experience any reduction in revenues resulting from an inability of an electric utility company in the system to recover the resulting increase in costs. The FERC stated it was not able to find that the Entergy system would not experience a reduction in revenues if refunds were awarded in this proceeding, which further supported the denial of refunds. In May 2016 the LPSC filed a request for rehearing of the FERC’s April 2016 order. In September 2016 the FERC issued an order denying the LPSC’s request for rehearing and reaffirming its denial of refunds for the 15-month refund effective period. The LPSC has appealed the April and September 2016 orders to the U.S. Court of Appeals for the D.C. Circuit. Oral argument before the D.C. Circuit was held before the D.C. Circuit in February 2018 and a decision is pending.

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 requesting that the FERC dismiss the complaint on

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

the merits without hearing because the LPSC has failed to meet its burden of showing any violation of the System Agreement and failed to produce any evidence of imprudent action by the Entergy System. In their response, the Utility operating companies explained that the System Agreement clearly contemplates 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 LPSC filed direct testimony in the proceeding alleging, among other things, (1) that Entergy violated the System Agreement by permitting Entergy Arkansas to make non-requirements sales to non-affiliated third parties rather than making such energy available to the other Utility operating companies' customers; and (2) that over the period 2000 - 2009, these non-requirements sales caused harm to the Utility operating companies' customers and these customers should be compensated for this harm by Entergy. In subsequent testimony, the LPSC modified its original damages claim in favor of quantifying damages by re-running intra-system bills. The Utility operating companies believe the LPSC's allegations are without merit. A hearing in the matter was held in August 2010.

In December 2010 the ALJ issued an initial decision. The ALJ found that the System Agreement allowed for Entergy Arkansas to make the sales to third parties but concluded that the sales should be accounted for in the same manner as joint account sales. The ALJ concluded that "shareholders" should make refunds of the damages to the Utility operating companies, along with interest. Entergy disagreed with several aspects of the ALJ's initial decision and in January 2011 filed with the FERC exceptions to the decision.

The FERC issued a decision in June 2012 and held that, while the System Agreement is ambiguous, it does 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 does 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. Quantifying the effect of the FERC's decision requires re-running intra-system bills for a ten-year period, and the FERC in its decision established further hearing procedures to determine the calculation of the effects. In July 2012, Entergy and the LPSC filed requests for rehearing of the FERC's June 2012 decision. A hearing was held in May 2013 to quantify the effect of repricing the opportunity sales in accordance with the FERC's June 2012 decision.

In August 2013 the presiding judge issued an initial decision in the calculation proceeding. The initial decision concluded that the methodology proposed by the LPSC, rather than the methodologies proposed by Entergy or the FERC Staff, should be used to calculate the payments that Entergy Arkansas is to make to the other Utility operating companies. The initial decision also concluded that the other System Agreement service schedules should not be adjusted and that payments by Entergy Arkansas should not be reflected in the rough production cost equalization bandwidth calculations for the applicable years. The initial decision recognized that the LPSC's methodology would result in an inequitable windfall to the other Utility operating companies and, therefore, concluded that any payments by Entergy Arkansas should be reduced by 20%. The LPSC, the APSC, the City Council, and FERC staff filed briefs on exceptions and/or briefs opposing exceptions. Entergy filed a brief on exceptions requesting that the FERC reverse the initial decision and

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

a brief opposing certain exceptions taken by the LPSC and FERC staff.

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.

In May 2016, Entergy Services filed a request for rehearing of the FERC's April 2016 order arguing that payments made by Entergy Arkansas should be reduced as a result of the timing of the LPSC's approval of certain contracts. Entergy Services also filed a request for clarification and/or rehearing of the FERC's April 2016 order addressing the ALJ's August 2013 initial decision. The APSC and the LPSC also filed requests for rehearing of the FERC's April 2016 order. In September 2017 the FERC issued an order denying the request for rehearing on the issue of whether any payments by Entergy Arkansas to the other Utility operating companies should be reduced due to the timing of the LPSC's approval of Entergy Arkansas's wholesale baseload contract with Entergy Louisiana. In November 2017 the FERC issued an order denying all of the remaining requests for rehearing of the April 2016 order. In November 2017, Entergy Services filed a petition for review in the D.C. Circuit of the FERC's orders in the first two phases of the opportunity sales case. In December 2017 the D.C. Circuit granted Entergy Services's request to hold the appeal in abeyance pending final resolution of the related proceeding still pending with the FERC. In January 2018 the APSC and the LPSC filed separate petitions for review in the D.C. Circuit, and the D.C. Circuit consolidated the appeals with Entergy Services's appeal and held all of the appeals in abeyance.

Pursuant to the procedural schedule established in the case, Entergy Services re-ran intra-system bills for the ten-year period 2000-2009 to quantify the effects of the FERC's ruling. In November 2016 the LPSC submitted testimony disputing certain aspects of the calculations. A hearing was held in May 2017. In July 2017, the ALJ issued an initial decision concluding that Entergy Arkansas should pay \$86 million plus interest to the other Utility operating companies. 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. The case is pending before the FERC. No payments will be made or received by the Utility operating companies

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

until the FERC issues an order reviewing the initial decision and Entergy submits a subsequent filing to comply with that order.

The effect of the FERC's decisions thus far in the case would be that Entergy Arkansas will make payments to some or all of the other Utility operating companies. Because further proceedings will still occur in the case, the amount and recipients of payments by Entergy Arkansas are unknown at this time. 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 includes interest, for its estimated increased costs and payment to the other Utility operating companies. This estimate is subject to change depending on how the FERC resolves the issues that are still outstanding in the case, including its review of the July 2017 initial decision. Entergy Arkansas's increased costs will be attributed to Entergy Arkansas's retail and wholesale businesses, and it is not probable that Entergy Arkansas will recover the wholesale portion. Entergy Arkansas, therefore, recorded a deferred fuel regulatory asset in the first quarter 2016 of approximately \$75 million, which represents its estimate of the retail portion of the costs. 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. Because management currently expects to recover the retail portion of the costs through a base rate proceeding or newly proposed rider, the regulatory asset is reflected as Other regulatory assets as of December 31, 2017.

Complaint Against System Energy

In January 2017 the APSC and MPSC filed a complaint with the FERC against System Energy. The complaint seeks a reduction in the return on equity component of the Unit Power Sales Agreement pursuant to which System Energy sells its Grand Gulf capacity and energy to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans. Entergy Arkansas also sells some of its Grand Gulf capacity and energy to Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans under separate agreements. The current return on equity under the Unit Power Sales Agreement is 10.94%. The complaint alleges that the return on equity is unjust and unreasonable because current capital market and other considerations indicate that it is excessive. The complaint requests the FERC to institute proceedings to investigate the return on equity and establish a lower return on equity, and also requests that the FERC establish January 23, 2017 as a refund effective date. The complaint includes return on equity analysis that purports to establish that the range of reasonable return on equity for System Energy is between 8.37% and 8.67%. System Energy answered the complaint in February 2017 and disputes that a return on equity of 8.37% to 8.67% is just and reasonable. The LPSC and the City Council intervened in the proceeding expressing support for the complaint. System Energy is recording a provision against revenue for the potential outcome of this proceeding. In September 2017 the FERC established a refund effective date of January 23, 2017, consolidated the return on equity complaint with the proceeding described in Unit Power Sales Agreement below, and directed the parties to engage in settlement proceedings before an ALJ. If the parties fail to come to an agreement during settlement proceedings, a prehearing conference will be held to establish a procedural schedule for hearing proceedings.

Unit Power Sales Agreement

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

In August 2017, System Energy submitted to the FERC proposed amendments to the Unit Power Sales Agreement pursuant to which System Energy sells its Grand Gulf capacity and energy to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans. The filing proposes limited amendments to the Unit Power Sales Agreement to adopt (1) updated rates for use in calculating Grand Gulf plant depreciation and amortization expenses and (2) updated nuclear decommissioning cost annual revenue requirements, both of which are recovered through the Unit Power Sales Agreement rate formula. The proposed amendments would result in lower charges to the Utility operating companies that buy capacity and energy from System Energy under the Unit Power Sales Agreement. The proposed changes are based on updated depreciation and nuclear decommissioning studies that take into account the renewal of Grand Gulf's operating license for a term through November 1, 2044. System Energy requested that the FERC accept the amendments effective October 1, 2017.

In September 2017 the FERC accepted System Energy's proposed Unit Power Sales Agreement amendments, subject to further proceedings to consider the justness and reasonableness of the amendments. Because the amendments propose a rate decrease, the FERC also initiated an investigation under Section 206 of the Federal Power Act to determine if the rate decrease should be lower than proposed. The FERC accepted the proposed amendments effective October 1, 2017, subject to refund pending the outcome of the further settlement and/or hearing proceedings, and established a refund effective date of October 11, 2017 with respect to the rate decrease. The FERC also consolidated the Unit Power Sales Agreement amendment proceeding with the proceeding described in **Complaint Against System Energy** above, and directed the parties to engage in settlement proceedings before an ALJ. If the parties fail to come to an agreement during settlement proceedings, a prehearing conference will be held to establish a procedural schedule for hearing proceedings.

NOTE 3. INCOME TAXES

Details regarding income taxes are presented on FERC Form 1 pages 261-267 and 274-277.

Carryovers

The Registrant Subsidiaries' estimated tax attributes carryovers and their expiration dates as of December 31, 2017 are as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
Federal net operating losses	\$77 million	\$4.3 billion	\$86.6 million	\$1.1 billion	—	—
Year(s) of expiration	2030-2037	2035-2037	2030-2037	2037	N/A	N/A
State net operating losses	—	\$5 billion	—	\$1.2 billion	—	—
Year(s) of expiration	N/A	2029-2037	N/A	2037	N/A	N/A
Misc. federal credits	\$2.7 million	\$1.7 million	\$2.7 million	\$2.1 million	\$0.6 million	\$2.5 million

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Year(s) of expiration	2029-2036	2029-2036	2029-2036	2029-2036	2029-2036	2029-2036
State credits	—	—	\$4.9 million	—	\$3.2 million	\$10 million
Year(s) of expiration	N/A	N/A	2018-2021	N/A	2026	2018-2021

As a result of the accounting for uncertain tax positions, the amount of the deferred tax assets reflected in the financial statements is less than the amount of the tax effect of the federal and state net operating loss carryovers and tax credit carryovers.

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 2017, 2016, and 2015 is as follows:

2017	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)		
Gross balance at January 1, 2017	\$2,503	\$2,440,339	\$12,206	\$166,230	\$15,946	\$472,372
Additions based on tax positions related to the current year (a)	8,974	32,843	2,105	509,183	1,747	909
Additions for tax positions of prior years	3,682	235,331	1,267	13,364	3,115	1,432
Reductions for tax positions of prior years	(132,875)	(190,056)	(456)	(9,233)	(4,409)	(29,202)
Gross balance at December 31, 2017	(117,716)	2,518,457	15,122	679,544	16,399	445,511
Offsets to gross unrecognized tax benefits:						
Loss carryovers	—	(1,591,907)	(15,122)	(441,374)	(638)	(12,536)
Unrecognized tax benefits net of unused tax attributes and payments	(\$117,716)	\$926,550	\$—	\$238,170	\$15,761	\$432,975
2016	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)		
Gross balance at January 1, 2016	\$25,445	\$1,690,661	\$19,482	\$53,897	\$13,462	\$478,318
Additions based on tax positions related	16,868	931,720	2,662	33,912	2,002	5,318

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Louisiana	\$575.8	\$473.3	\$692.7
Entergy Mississippi	\$—	\$—	\$8.1
Entergy New Orleans	\$31.7	\$33.6	\$50.7
Entergy Texas	\$4.4	\$7.0	\$5.2
System Energy	\$—	\$—	\$0.7

The Registrant Subsidiaries accrue interest and penalties related to unrecognized tax benefits in income tax expense. Penalties have not been accrued. Accrued balances for the possible payment of interest are as follows:

	December 31,		
	2017	2016	2015
	(In Millions)		
Entergy Arkansas	\$1.6	\$1.4	\$1.3
Entergy Louisiana	\$14.1	\$8.4	\$9.3
Entergy Mississippi	\$1.0	\$0.8	\$0.4
Entergy New Orleans	\$2.1	\$1.5	\$1.8
Entergy Texas	\$0.4	\$1.2	\$1.2
System Energy	\$8.5	\$3.7	\$0.7

Income Tax Audits

Entergy and its subsidiaries file U.S. federal and various state and foreign income tax returns. IRS examinations are complete for years before 2012. All state taxing authorities' examinations are complete for years before 2010. Entergy regularly negotiates with the IRS to achieve settlements. The resolution of audit issues could result in significant changes to the amounts of unrecognized tax benefits in the next twelve months.

2006-2007 IRS Audit

In the first quarter 2015, the IRS finalized tax and interest computations from the 2006-2007 audit that resulted in a reversal of Entergy's provision for uncertain tax positions related to accrued interest of approximately \$20 million, including decreases of approximately \$4 million for Entergy Arkansas, \$11 million for Entergy Louisiana, and \$1 million for System Energy.

2008-2009 IRS Audit

In the fourth quarter 2009, Entergy filed Applications for Change in Accounting Method (the "2009 CAM") for tax purposes with the IRS for certain costs under Section 263A of the Internal Revenue Code. In the Applications, Entergy proposed to treat the nuclear decommissioning liability associated with the operation of its nuclear power plants as a production cost properly includable in cost of goods sold. The effect of the 2009 CAM was a \$5.7 billion reduction

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

in 2009 taxable income. The 2009 CAM was adjusted to \$9.3 billion in 2012.

In the fourth quarter 2012, the IRS disallowed the reduction to 2009 taxable income related to the 2009 CAM. In the third quarter 2013, the Internal Revenue Service issued its Revenue Agent Report (RAR) for the tax years 2008-2009. As a result of the issuance of this RAR, Entergy and the IRS resolved all of the 2008-2009 issues described above except for the 2009 CAM. Entergy disagreed with the IRS's disallowance of the 2009 CAM and filed a protest with the IRS Appeals Division in October 2013.

In August 2015, Entergy and the IRS agreed on the treatment of the 2009 position regarding nuclear decommissioning liabilities from the 2008-2009 audit. The agreement provides that Entergy is entitled to deduct approximately \$118 million of the \$9.3 billion claimed in 2009. The agreement effectively settled all matters pertaining to the 2009 tax year and increased Entergy's 2009 federal income tax liability by \$2.4 million.

2010-2011 IRS Audit

The IRS completed its examination of the 2010 and 2011 tax years and issued its 2010-2011 RAR in June 2016. Entergy agreed to all proposed adjustments contained in the RAR. As a result of the issuance of the RAR, Entergy Louisiana was able to recognize previously unrecognized tax benefits as follows:

- Entergy and the IRS agreed that \$148.6 million of the proceeds received by Entergy Louisiana in 2010 from the Louisiana Utilities Restoration Corporation (LURC), an instrumentality of the State of Louisiana, for the financing of Hurricane Gustav and Hurricane Ike storm costs pursuant to Act 55 of the Louisiana Regular Session of 2007 (Louisiana Act 55) were not taxable. Because the treatment of the financing is settled, Entergy recognized previously unrecognized tax benefits totaling \$63.5 million, of which Entergy Louisiana recorded \$61.6 million. Entergy Louisiana also accrued a regulatory liability of \$16.1 million (\$9.9 million net-of-tax) in accordance with the terms of Entergy Louisiana's previous settlement agreement approved by the LPSC regarding Entergy Louisiana's obligation to pay to customers savings associated with the Act 55 financing.
- Entergy and the IRS agreed upon the tax treatment of Entergy Louisiana's regulatory liability related to the Vidalia purchased power agreement. As a result, Entergy Louisiana recognized a previously unrecognized tax benefit of \$74.5 million.

Other Tax Matters

Tax Cuts and Jobs Act

Deferred tax liabilities and assets have been adjusted for the effect of the enactment of H.R. 1, also known as the Tax Cuts and Jobs Act (the Act), signed by President Trump on December 22, 2017. The most significant effect of the Act for Entergy and the Registrant Subsidiaries is the change in the federal corporate income tax rate from 35% to 21%,

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

effective January 1, 2018. Other significant provisions and their effect on Entergy and the Registrant Subsidiaries are summarized below.

The Act limits the deduction for net business interest expense in certain circumstances. The new limitation does not apply to interest expense, however, that is properly allocable to a trade or business that furnishes or sells electrical energy, gas, or steam through a local distribution system, or transports gas or steam by pipeline if the rates for such furnishing or sale are subject to ratemaking by a government entity or instrumentality or by a public utility commission. Accordingly, the potential interest expense disallowance is not expected to have a material effect on Entergy's or the Registrant Subsidiaries' interest deductions.

The Act extends and modifies the additional first-year depreciation deduction (bonus depreciation). The Act excludes from bonus-eligible qualified property, however, any property used in a trade or business that furnishes or sells electrical energy, gas, or steam through a local distribution system, or transportation of gas or steam by pipeline if the rates for furnishing those services are subject to ratemaking by a government entity or instrumentality or by a public utility commission. Accordingly, the extension of bonus depreciation and modifications generally do not apply to Entergy or the Registrant Subsidiaries.

The Act limits the net operating loss (NOL) deduction for a given year to 80% of taxable income, effective with respect to losses arising in tax years beginning after December 31, 2017. Only NOLs generated after December 31, 2017 are subject to the 80% limitation. Prior law generally provided a two-year carryback and 20-year carryforward for NOLs. The Act provides for the indefinite carryforward of NOLs arising in tax years ending after December 31, 2017, as opposed to the current 20-year carryforward. Because of the indefinite carryforward, the new limitations on NOL utilization are not expected to have a material effect on Entergy or the Registrant Subsidiaries.

The Act also modified Internal Revenue Code section 162(m), which limits the deduction for compensation with respect to certain covered employees to no more than \$1 million per year. The Act includes performance-based compensation in the annual computation of the section 162 limitation. The changes are expected to result in an increase in disallowed compensation expense, but this limitation is not expected to have a material effect on Entergy or the Registrant Subsidiaries.

Other provisions that are not expected to have a material effect on Entergy or the Registrant Subsidiaries include the following:

- repeal of the corporate alternative minimum tax (AMT),
- modification to the capital contribution rules under Internal Revenue Code section 118,
- repeal of domestic production activities deduction, and
- fundamental changes to the taxation of multinational entities.

With respect to the federal corporate income tax rate change from 35% to 21%, Entergy and the Registrant Subsidiaries believe it is probable that a significant portion of the decrease in the net accumulated deferred income tax liability, which is often referred to as "excess ADIT," will be returned to customers. Accordingly, it is appropriate for Entergy and the Registrant Subsidiaries to establish a regulatory liability for the probable reduction in future revenue.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy's December 31, 2017 balance sheet reflects a regulatory liability of \$2.9 billion due to a re-measurement of deferred tax assets and liabilities resulting from the income tax rate change. Entergy's regulatory liability for income taxes includes a gross-up at the applicable tax rate because of the effect that excess ADIT has on the ratemaking formula. The regulatory liability for income taxes includes the effect of a) the reduction of the net deferred tax liability resulting in excess ADIT, b) the tax gross-up of excess ADIT, and c) the effect of the new tax rate on the previous net regulatory asset for income taxes. For the same reasons, the Registrant Subsidiaries' December 31, 2017 balance sheets reflect net regulatory liabilities for income taxes as follows: Entergy Arkansas, \$986 million; Entergy Louisiana, \$725 million; Entergy Mississippi, \$411 million; Entergy New Orleans, \$119 million; Entergy Texas, \$413 million; and System Energy, \$246 million.

Excess ADIT is generally classified into two categories: 1) the portion that is subject to the normalization requirements of the Act, i.e., "protected", and 2) the portion that is not subject to such normalization provisions, referred to as "unprotected". The Act provides that the normalization method of accounting for income taxes is required for excess ADIT associated with public utility property. The Act provides for the use of the average rate assumption method (ARAM) for the determination of 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 return the protected portion of the excess ADIT in conformity with the normalization requirements. The Registrant Subsidiaries' net regulatory liability for income taxes includes protected excess ADIT as follows: Entergy Arkansas, \$554 million; Entergy Louisiana, \$782 million; Entergy Mississippi, \$274 million; Entergy New Orleans, \$71 million; Entergy Texas, \$276 million; and System Energy, \$217 million.

The return period of the unprotected excess ADIT is subject to the regulatory process in each jurisdiction and has yet to be determined. Further, a portion of the unprotected excess ADIT amount is associated with amounts previously securitized and may be treated differently than other unprotected excess ADIT consistent with applicable agreements and/or not be subject to the same schedule for the return to customers as the remaining unprotected excess ADIT. The Registrant Subsidiaries' net regulatory liability for income taxes includes unprotected excess ADIT as follows: Entergy Arkansas, \$467 million; Entergy Louisiana, \$410 million; Entergy Mississippi, \$162 million; Entergy New Orleans, \$37 million; Entergy Texas, \$198 million; and System Energy, \$76 million. In addition to the protected and unprotected excess ADIT amounts, the net regulatory liability for income taxes includes other regulatory assets and liabilities for income taxes associated with AFUDC, which is described in Note 1 to the financial statements.

For a discussion of the proceedings commenced or other responses by Entergy's regulators to the Act, see Note 2 to the financial statements.

Not all of Entergy's excess ADIT is included in ratemaking. Consequently, Entergy recorded a net decrease in deferred tax assets of \$560 million for which there is a corresponding charge to income tax expense for the year ended December 31, 2017. The corresponding income tax expense (or benefit) recorded by the Registrant Subsidiaries is as follows: Entergy Arkansas, (\$3 million); Entergy Louisiana, \$217 million; Entergy Mississippi, \$3 million; Entergy New Orleans, \$6 million; Entergy Texas, \$3 million; and System Energy, \$0.

Included in the effect of the computation of the changes in deferred tax assets and liabilities is the recognition

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

threshold and measurement of uncertain tax positions resulting in unrecognized tax benefits. The final economic outcome of such unrecognized tax benefits is generally the result of a negotiated settlement with the IRS that often differs from the amount that is recorded as realizable under GAAP. The intrinsic uncertainty with respect to all such tax positions means that the difference between current estimates of such amounts likely to be realized and actual amounts realized upon settlement may have an effect on income tax expense and the regulatory liability for income taxes in future periods.

Entergy's accounting for the effects of the Act is complete using the best estimates and information available to it at this time. Entergy anticipates that the Act, including the federal corporate income tax rate change, however, will continue to have ramifications that require adjustments in the future as certain events occur. These events include: 1) the evaluation by regulators in all of Entergy's jurisdictions regarding the ratemaking treatment of the Act and excess ADIT; 2) the filing of all applicable federal and state income tax returns that include any tax elections that may change estimates accrued in the year-end recording process; and 3) additional guidance, interpretations, or rulings by the U.S. Department of the Treasury or the IRS. The potential exists for these types of events to result in future adjustments because of the difference in the federal corporate income tax rate between past and future periods and the effect of the tax rate change on ratemaking. In turn, these items also will potentially affect the regulatory liability for income taxes.

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, 2017 as follows:

Company	Expiration Date	Amount of Facility	Interest Rate (a)	Amount Drawn as of December 31, 2017	Letters of Credit Outstanding as of December 31, 2017
Entergy Arkansas	April 2018	\$20 million (b)	2.82%	—	—
Entergy Arkansas	August 2022	\$150 million (c)	2.82%	—	—
Entergy Louisiana	August 2022	\$350 million (c)	2.82%	—	\$9.1 million
Entergy Mississippi	May 2018	\$10 million (d)	3.07%	—	—
Entergy Mississippi	May 2018	\$20 million (d)	3.07%	—	—
Entergy Mississippi	May 2018	\$35 million (d)	3.07%	—	—
Entergy Mississippi	May 2018	\$37.5 million (d)	3.07%	—	—
Entergy New Orleans	November 2018	\$25 million (c)	3.04%	—	\$0.8 million
Entergy Texas	August 2022	\$150 million (c)	3.07%	—	\$25.6 million

(a) The interest rate is the estimated interest rate as of December 31, 2017 that would have been applied to outstanding borrowings under the facility.

(b) Borrowings under this Entergy Arkansas credit facility may be secured by a security interest in its accounts receivable at Entergy Arkansas's option.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- (c) The credit facility permits 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; \$10 million for Entergy New Orleans; and \$30 million for Entergy Texas.
- (d) Borrowings under the Entergy Mississippi credit facilities may be secured by a security interest in its accounts receivable at Entergy Mississippi's option.

The commitment fees on the credit facilities range from 0.075% to 0.275% of the undrawn commitment amount. 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 entered into one or more uncommitted standby letter of credit facilities as a means to post collateral to support its obligations to MISO. Following is a summary of the uncommitted standby letter of credit facilities as of December 31, 2017:

Company	Amount of Uncommitted Facility	Letter of Credit Fee	Letters of Credit Issued as of December 31, 2017 (a)
Entergy Arkansas	\$25 million	0.70%	\$1.0 million
Entergy Louisiana	\$125 million	0.70%	\$29.7 million
Entergy Mississippi	\$40 million	0.70%	\$15.3 million
Entergy New Orleans	\$15 million	1.00%	\$1.4 million
Entergy Texas	\$50 million	0.70%	\$22.8 million

- (a) As of December 31, 2017, letters of credit posted with MISO covered financial transmission right exposure of \$0.2 million for Entergy Arkansas, \$0.1 million for Entergy Mississippi, and \$0.05 million for Entergy Texas. 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 current FERC-authorized limits are effective through October 31, 2019. 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 and the other internal borrowing arrangements are inter-company borrowing arrangements designed to reduce the Utility 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, 2017 (aggregating both internal and external short-term borrowings) for the Registrant Subsidiaries:

Authorized	Borrowings
(In Millions)	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Arkansas	\$250	\$166
Entergy Louisiana	\$450	—
Entergy Mississippi	\$175	—
Entergy New Orleans	\$150	—
Entergy Texas	\$200	—
System Energy	\$200	—

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 APSC that extends through December 2018.

NOTE 6. PREFERRED EQUITY

Details of preferred equity are presented on FERC Form 1 pages 250-251.

NOTE 7. COMMON EQUITY

Details of common equity are presented on FERC Form 1 pages 250-251.

Retained Earnings and Dividend Restrictions

Provisions within the articles of incorporation relating to preferred stock of each of Entergy Arkansas and Entergy Mississippi could restrict the payment of cash dividends or other distributions on their common and preferred equity if such payment were to occur when, or result in, a ratio of common stock equity to total capitalization of 25% or less.

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 commissions, and governmental agencies in the ordinary course of business. While management is unable to predict the outcome of such proceedings, management does not believe that the ultimate resolution of these matters will have a material 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.

ANO Damage, Outage, and NRC Reviews

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

In March 2013, during a scheduled refueling outage at ANO 1, a contractor-owned and operated heavy-lifting apparatus collapsed while moving the generator stator out of the turbine building. The collapse resulted in the death of an ironworker and injuries to several other contract workers, caused ANO 2 to shut down, and damaged the ANO turbine building. The total cost of assessment, restoration of off-site power, site restoration, debris removal, and replacement of damaged property and equipment was approximately \$95 million. Entergy Arkansas is pursuing its options for recovering damages that resulted from the stator drop, including its insurance coverage and legal action. During 2014, Entergy Arkansas collected \$50 million from Nuclear Electric Insurance Limited (NEIL), a mutual insurance company that provides property damage coverage to the members' nuclear generating plants. Litigation remains pending.

In addition, Entergy Arkansas incurred replacement power costs for ANO 2 power during its outage and incurred incremental replacement power costs for ANO 1 power because the outage extended beyond the originally-planned duration of the refueling outage. In February 2014 the APSC approved Entergy Arkansas's request to exclude from the calculation of its revised energy cost rate \$65.9 million of deferred fuel and purchased energy costs incurred in 2013 as a result of the ANO stator incident. The APSC authorized Entergy Arkansas to retain the \$65.9 million in its deferred fuel balance with recovery to be reviewed in a later period after more information regarding various claims associated with the ANO stator incident is available. 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 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 previously noted, subject to certain timelines and conditions set forth in the settlement agreement.

Shortly after the stator incident, the NRC deployed an augmented inspection team to review the plant's response. In July 2013 a second team of NRC inspectors visited ANO to evaluate certain items that were identified as requiring follow-up inspection to determine whether performance deficiencies existed. In March 2014 the NRC issued an inspection report on the follow-up inspection that discussed two preliminary findings, one that was preliminarily determined to be "red with high safety significance" for Unit 1 and one that was preliminarily determined to be "yellow with substantial safety significance" for Unit 2, with the NRC indicating further that these preliminary findings may warrant additional regulatory oversight. This report also noted that one additional item related to flood barrier effectiveness was still under review. In June 2014 the NRC classified both findings as "yellow with substantial safety significance."

In March 2015, after several NRC inspections and regulatory conferences, the NRC issued a letter notifying Entergy of its decision to move ANO into the "multiple/repetitive degraded cornerstone column," or Column 4, of the NRC's Reactor Oversight Process Action Matrix. Placement into Column 4 requires significant additional NRC inspection activities at the ANO site, including a review of the site's root cause evaluation associated with flood barrier effectiveness and stator issues, an assessment of the effectiveness of the site's corrective action program, an additional design basis inspection, a safety culture assessment, and possibly other inspection activities consistent with the NRC's Inspection Procedure. Entergy Arkansas incurred incremental costs of approximately \$53 million in 2015 to prepare for the NRC inspection that began in early 2016. Excluding remediation and response costs that may result from the additional NRC inspection activities, Entergy Arkansas also incurred approximately \$44 million in 2016 in support of

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

NRC inspection activities and to implement Entergy Arkansas’s performance improvement initiatives developed in 2015. A lesser amount of incremental expense is expected to be ongoing annually after 2016, until ANO transitions out of Column 4.

The NRC completed the supplemental inspection required for ANO’s Column 4 designation in February 2016, and published its inspection report in June 2016. In its inspection report, the NRC concluded that the ANO site is being operated safely and that Entergy understands the depth and breadth of performance concerns associated with ANO’s performance decline. Also in June 2016, the NRC issued a confirmatory action letter to confirm the actions Entergy Arkansas has taken and will continue to take to improve performance at ANO. The NRC will verify the completion of those actions through quarterly follow-up inspections, the results of which will determine when ANO should transition out of Column 4. There have been no significant issues arising from the follow-up inspections.

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 Court of Appeals 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. Management cannot predict the potential timing or magnitude of future spent fuel fee revisions that may occur.

Because the DOE has not begun accepting spent fuel, it is in non-compliance with the Nuclear Waste Policy Act of 1982 and has breached 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 2016 related to Entergy’s nuclear owner licensee subsidiaries’ litigation with the DOE.

In July 2016 the U.S. Court of Federal Claims issued a final judgment in the amount of \$31 million in favor of

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Arkansas and against the DOE in the second round ANO damages case. Entergy Arkansas received payment from the U.S. Treasury in October 2016. The effects of recording the judgment were reductions to plant, nuclear fuel expense, and other operation and maintenance expense. The ANO damages awarded included \$6 million related to costs previously capitalized, \$19 million related to costs previously recorded as nuclear fuel expense, \$5 million related to costs previously recorded as other operation and maintenance expense, and \$1 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 2005 for a term through 2025. 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 private insurance underwritten by American Nuclear Insurers (ANI) and provides public liability insurance coverage of \$450 million for each operating reactor (prior to January 1, 2017, the primary level of insurance was \$375 million). If this amount is not sufficient to cover claims arising from an accident, the second level, Secondary Financial Protection, applies. In 2016 the NRC approved Vermont Yankee's exemption request to lower their limits from \$375 million to \$100 million effective April 15, 2016.
2. Within the Secondary Financial Protection level, 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 \$127.3 million per reactor per incident (Entergy's maximum total contingent obligation per incident is \$1.146 billion). This retrospective premium is payable at a rate currently set at approximately \$19 million per year per incident per nuclear power reactor.
3. In the event that one or more acts of terrorism cause a nuclear power plant accident, which results in third-party damages – off-site property and environmental damage, off-site bodily injury, and on-site third-party bodily injury (i.e. contractors), the primary level provided by ANI combined with the Secondary Financial Protection would provide approximately \$13 billion in coverage. The Terrorism Risk Insurance Reauthorization Act of 2007 created a government program that provides for up to \$100 billion in coverage in excess of existing coverage for a terrorist event. Under current law, the Terrorism Risk Insurance Act extends through 2020.

Currently, 102 nuclear reactors are participating in the Secondary Financial Protection program. Effective April 15, 2016 the NRC granted Vermont Yankee's exemption request and it was allowed to withdraw from participation in

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

this layer of financial protection. The Secondary Financial Protection program provides approximately \$13 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.

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 premature decommissioning expense, to the members' nuclear generating plants. The property damage insurance limits procured by Entergy for its Utility plants and Entergy Wholesale Commodity plants are in compliance with the financial protection requirements of the NRC.

The Utility plants' (ANO 1 and 2, Grand Gulf, River Bend, and Waterford 3) property damage insurance limits are \$1.5 billion per occurrence at each plant with an additional \$100 million per occurrence that is shared among the plants. Property damage from earthquake and volcanic eruption is excluded from the first \$500 million in coverage for all Utility 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 is included in the first \$500 million for Waterford 3 and River Bend. Property damage from wind for all of the Utility nuclear plants includes 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. Effective April 1, 2017, the maximum amounts of such possible assessments per occurrence were as follows:

	<u>Assessments</u>
	(In Millions)
Utility:	
Entergy Arkansas	\$40.3
Entergy Louisiana	\$49.4
Entergy Mississippi	\$0.11
Entergy New Orleans	\$0.11
Entergy Texas	N/A
System Energy	\$22.3

Potential assessments for the Entergy Wholesale Commodities plants are covered by insurance obtained through NEIL's

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

reinsurers.

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 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 up to \$400 million per occurrence, "each and every loss" basis in excess of a \$20 million self-insured retention with the exception of 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 \$125 million on an annual aggregate basis in excess of a \$40 million self-insured retention. The coverage provided by the insurance program for the Entergy New Orleans gas distribution system is limited to \$50 million per occurrence and is subject to the same annual aggregate limits and retentions listed above for earthquake shock, flood, and named windstorm, including associated storm surge.

Covered property generally includes power plants, substations, facilities, inventories, and gas distribution-related properties. 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, including the owners of the nuclear power plants in the Entergy Wholesale Commodities segment. Entergy also purchases \$300 million in terrorism insurance coverage for its conventional property. The Terrorism Risk Insurance Reauthorization Act of 2007 created a government program that provides for up to \$100 billion in coverage in excess of existing coverage for a terrorist event. Under current law, the Terrorism Risk Insurance Act extends through 2020.

Prior to June 1, 2017, Entergy purchased additional coverage for some of its non-regulated, non-generation assets in addition to the insurance procured via the conventional property insurance program. The policy served to buy-down the conventional property insurance policy's \$20 million deductible and was placed on a scheduled location basis.

Employment and Labor-related Proceedings

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The Registrant Subsidiaries and other Entergy subsidiaries 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 third parties not selected for open positions or providing services directly or indirectly to one or more of the Registrant Subsidiaries and other Entergy subsidiaries. Generally, the amount of damages being sought is not specified in these proceedings. These actions 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 plans. Entergy and the Registrant Subsidiaries 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 Utility operating companies.

Asbestos Litigation (Entergy Arkansas, Entergy Louisiana, Entergy New Orleans, and Entergy Texas)

Numerous lawsuits have been filed in federal and state courts, primarily by contractor employees who worked in the 1940-1980s timeframe, primarily against Entergy Texas, and to a lesser extent the other Utility operating companies, as premises owners of power plants, for damages caused by alleged exposure to asbestos. Many other defendants are named in these lawsuits as well. Currently, there are approximately 200 lawsuits involving approximately 500 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 (Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and System Energy)

System Energy has agreed to sell 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. 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. The agreement will remain in effect until terminated by the parties and the termination is approved by the FERC, most likely upon Grand Gulf's retirement from service. In December 2016 the NRC granted the extension of Grand Gulf's operating license to 2044. Monthly obligations are based on actual capacity and energy costs. The average monthly payments for 2017 under the agreement are approximately \$19.5 million for Entergy Arkansas, \$7.8 million for Entergy Louisiana, \$17 million for

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Mississippi, and \$9.4 million for Entergy New Orleans. See Note 2 to the financial statements for discussion of the complaint filed with the FERC against System Energy seeking a reduction in the return on equity component of 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 an amount sufficient to amortize the cost of Grand Gulf 2 over 27 years (See Reallocation Agreement terms below) and 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 obligations. Since commercial operation of Grand Gulf began, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments under the Availability Agreement have ever been required. If Entergy Arkansas or Entergy Mississippi fails to make its Unit Power Sales Agreement payments, and System Energy is unable to obtain funds from other sources, Entergy Louisiana and Entergy New Orleans could become subject to claims or demands by System Energy or its creditors for payments or advances under the Availability Agreement (or the assignments thereof) equal to the difference between their required Unit Power Sales Agreement payments and their required Availability Agreement payments.

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

System Energy, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans entered into the Reallocation Agreement relating to the sale of capacity and energy from Grand Gulf and the related costs, in which Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans agreed to assume all of Entergy Arkansas’s responsibilities and obligations with respect to Grand Gulf under the Availability Agreement. The FERC’s decision allocating a portion of Grand Gulf capacity and energy to Entergy Arkansas supersedes the Reallocation Agreement as it relates to Grand Gulf. Responsibility for any Grand Gulf 2 amortization amounts has been individually allocated (Entergy Louisiana-26.23%, Entergy Mississippi-43.97%, and Entergy New Orleans-29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect Entergy Arkansas’s obligation to System Energy’s lenders under the assignments referred to in the preceding paragraph. Entergy Arkansas would be liable for its share of such amounts if Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans were unable to meet their contractual obligations. No payments of any amortization amounts will be required so long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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. In addition, an insignificant amount of removal costs associated with non-nuclear power plants is also included in the decommissioning line item on the balance sheets.

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.

In accordance with ratemaking treatment and as required by regulatory accounting standards, the depreciation provisions for the Registrant Subsidiaries include a component for removal costs that are not asset retirement obligations under accounting standards. In accordance with regulatory accounting principles, the Registrant Subsidiaries have recorded regulatory assets (liabilities) in the following amounts to reflect their estimates of the difference between estimated incurred removal costs and estimated removal costs recovered in rates:

	December 31,	
	2017	2016
	(In Millions)	
Entergy Arkansas	\$176.9	\$128.5
Entergy Louisiana	(\$32.4)	(\$53.9)
Entergy Mississippi	\$91.6	\$82.0
Entergy New Orleans	\$44.8	\$40.1
Entergy Texas	\$55.2	\$33.5
System Energy	\$67.9	\$69.7

The cumulative decommissioning and retirement cost liabilities and expenses recorded in 2017 and 2016 by Entergy were as follows:

	Liabilities as of December 31, 2016	Accretion	Change in Cash Flow Estimate	Spending	Dispositions	Liabilities as of December 31, 2017
	(In Millions)					
Utility:						
Entergy Arkansas	\$924.4	\$56.8	\$—	\$—	\$—	\$981.2

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Entergy Louisiana	1,082.7	57.8	—	—	—	1,140.5
Entergy Mississippi	8.7	0.5	—	—	—	9.2
Entergy New Orleans	2.9	0.2	—	—	—	3.1
Entergy Texas	6.5	0.3	—	—	—	6.8
System Energy	854.2	43.4	(35.9)	—	—	861.7
Total	2,879.4	159.0	(35.9)	—	—	3,002.5

	Liabilities as of December 31, 2015	Liabilities Incurred	Accretion	Change in Cash Flow Estimate	Spending	Liabilities as of December 31, 2016	
			(In Millions)				
Utility:							
Entergy Arkansas	\$872.3	\$—	\$53.6	\$—	(\$1.5)	\$924.4	
Entergy Louisiana	1,027.9	—	54.8	—	—	1,082.7	
Entergy Mississippi	8.3	—	0.4	—	—	8.7	
Entergy New Orleans	2.7	—	0.2	—	—	2.9	
Entergy Texas	6.1	—	0.4	—	—	6.5	
System Energy	803.4	—	50.8	—	—	854.2	
Total	2,720.7	—	160.2	—	(1.5)	2,879.4	

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. As described below, during 2017 and 2016, Entergy updated decommissioning cost estimates for certain nuclear power plants.

Entergy maintains decommissioning trust funds that are committed to meeting its obligations for the costs of decommissioning the nuclear power plants. The fair values of the decommissioning trust funds and the related asset retirement obligation regulatory assets (liabilities) of Entergy as of December 31, 2017 and 2016 are as follows:

	2017		2016	
	Decommissioning Trust Fair Values	Regulatory Asset (Liability)	Decommissioning Trust Fair Values	Regulatory Asset (Liability)
	(In Millions)		(In Millions)	
Utility:				
ANO 1 and ANO 2	\$944.9	\$337.9	\$834.7	\$316.3

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

River Bend	\$818.2	(\$30.6)	\$712.8	(\$28.4)
Waterford 3	\$493.9	\$188.9	\$427.9	\$172.8
Grand Gulf	\$905.7	\$169.1	\$780.5	\$142.5

Coal Combustion Residuals

In June 2010 the EPA issued a proposed rule on coal combustion residuals (CCRs) that contained two primary regulatory options: (1) regulating CCRs destined for disposal in landfills or received (including stored) in surface impoundments as so-called “special wastes” under the hazardous waste program of RCRA Subtitle C; or (2) regulating CCRs destined for disposal in landfills or surface impoundments as non-hazardous wastes under Subtitle D of RCRA. Under both options, CCRs that are beneficially reused in certain processes would remain excluded from hazardous waste regulation. In April 2015 the EPA published the final CCR rule with the material being regulated under the second scenario presented above - as non-hazardous wastes regulated under RCRA Subtitle D. The final regulations create new compliance requirements including modified storage, new notification and reporting practices, product disposal considerations, and CCR unit closure criteria. Entergy believes that on-site disposal options will be available at its facilities, to the extent needed for CCR that cannot be transferred for beneficial reuse. In December 2016, the Water Infrastructure Improvements for the Nation Act (WIIN Act) was signed into law, which authorizes states to regulate coal ash rather than leaving primary enforcement to citizen suit actions. States may submit to the EPA proposals for permit programs. In September 2017 the EPA agreed to reconsider certain provisions of the CCR rule in light of the WIIN Act. The EPA has not yet initiated a new round of rulemaking and has not extended the existing mid-October 2017 groundwater monitoring deadline. Entergy met the existing monitoring deadline, is monitoring state agency actions, and will participate in the regulatory development process.

NOTE 10. LEASES

As of December 31, 2017 the Registrant Subsidiaries had non-cancelable operating leases for equipment, buildings, vehicles, and fuel storage facilities with minimum lease payments as follows (excluding power purchase agreement operating leases, nuclear fuel leases, and the Grand Gulf lease obligation, all of which are discussed elsewhere):

Operating Leases

<u>Year</u>	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
			(In Thousands)		
2018	\$17,009	\$21,814	\$11,771	\$1,646	\$3,469
2019	17,665	22,875	10,611	1,579	2,893
2020	11,483	17,790	8,969	1,382	1,934

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

2021	9,363	13,762	7,059	1,033	1,299
2022	6,834	10,067	5,007	662	862
Years thereafter	23,598	19,443	5,817	1,797	2,173
Minimum lease payments	\$85,952	\$105,751	\$49,234	\$8,099	\$12,630

Rental Expenses

Year	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Millions)						
2017	\$7.5	\$23.0	\$5.6	\$2.5	\$3.4	\$2.2
2016	\$8.0	\$17.8	\$4.0	\$0.9	\$2.8	\$1.6
2015	\$13.6	\$21.8	\$5.4	\$1.6	\$4.0	\$2.9

In addition to the above rental expense, railcar operating lease payments and oil tank facilities lease payments are recorded in fuel expense in accordance with regulatory treatment. Railcar operating lease payments were \$4.0 million in 2017, \$3.4 million in 2016, and \$4.7 million in 2015 for Entergy Arkansas and \$0.3 million in 2017, \$0.3 million in 2016, and \$1.1 million in 2015 for Entergy Louisiana. Oil tank facilities lease payments for Entergy Mississippi were \$1.6 million in 2017, \$1.6 million in 2016, and \$1.6 million in 2015.

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

Qualified Pension Plans

Entergy has eight qualified pension plans covering substantially all employees. 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, the Entergy Corporation Retirement Plan III, and the Entergy Corporation Retirement Plan IV for Bargaining Employees are non-contributory final average pay plans and provide pension benefits that are based on employees' credited service and compensation during employment. Effective as of the close of business on December 31, 2016, the Entergy Corporation Retirement Plan IV for Non-Bargaining Employees (Non-Bargaining Plan IV) was merged with and into Non-Bargaining Plan II. At the close of business on December 31, 2016, the liabilities for the accrued benefits and the assets attributable to such liabilities of all participants in Non-Bargaining Plan IV were assumed by and transferred to Non-Bargaining Plan II. There was no loss of vesting or benefit options or reduction of accrued benefits to affected participants as a result of this plan merger. Non-bargaining employees whose most recent date of hire is after June 30, 2014 participate in the Entergy Corporation Cash Balance Plan for Non-Bargaining Employees (Non-Bargaining Cash Balance Plan). Certain bargaining employees hired or rehired after June 30, 2014, or such later date provided for in their applicable collective bargaining

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

agreements, participate in the Entergy Corporation Cash Balance Plan for Bargaining Employees (Bargaining Cash Balance Plan). The Registrant Subsidiaries participate in these four plans: Non-Bargaining Plan I, Bargaining Plan I, Non-Bargaining Cash Balance Plan, and Bargaining Cash Balance Plan.

The assets of the six final average pay qualified pension plans are held in a master trust established by Entergy, and the assets of the two cash balance pension plans are held in a second master trust established by Entergy. Each pension plan has an undivided beneficial interest in each of the investment accounts in its respective master trust that is maintained by a trustee. Use of the master trusts 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 trusts 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 each trust to the various participating pension plans in that particular trust. The fair value of the trusts' assets is determined by the trustee and certain investment managers. For each trust, 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 trusts 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 2017, 2016, and 2015 qualified pension costs and amounts recognized as a regulatory asset and/or other comprehensive income, including amounts capitalized, for their employees included the following components:

2017	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						

Net periodic pension cost:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Service cost - benefits earned during the period	\$20,358	\$27,698	\$5,890	\$2,500	\$5,455	\$6,145
Interest cost on projected benefit obligation	51,776	59,235	14,927	7,163	13,569	12,364
Expected return on assets	(81,707)	(92,067)	(24,526)	(11,199)	(24,722)	(18,650)
Recognized net loss	46,560	49,417	12,213	6,632	9,241	11,857
Net pension cost	\$36,987	\$44,283	\$8,504	\$5,096	\$3,543	\$11,716

Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)

Arising this period:

Net loss	\$51,569	\$57,510	\$14,681	\$8,601	\$1,109	\$27,733
----------	----------	----------	----------	---------	---------	----------

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

Amortization of net loss	(46,560)	(49,417)	(12,213)	(6,632)	(9,241)	(11,857)
Total	\$5,009	\$8,093	\$2,468	\$1,969	(\$8,132)	\$15,876

Total recognized as net periodic pension (income)/cost, regulatory asset, and/or AOCI (before tax)

	\$41,996	\$52,376	\$10,972	\$7,065	(\$4,589)	\$27,592
--	----------	----------	----------	---------	-----------	----------

Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year

Net loss	\$53,650	\$57,800	\$14,438	\$7,816	\$10,503	\$14,859
----------	----------	----------	----------	---------	----------	----------

2016

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	\$20,724	\$28,194	\$6,250	\$2,625	\$5,664	\$6,263
Interest cost on projected benefit obligation	52,219	59,478	15,245	7,256	14,228	11,966
Expected return on assets	(79,087)	(88,383)	(23,923)	(10,748)	(24,248)	(17,836)
Recognized net loss	43,745	47,783	11,938	6,460	9,358	10,415
Net pension cost	\$37,601	\$47,072	\$9,510	\$5,593	\$5,002	\$10,808

Other changes in plan assets and

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

benefit obligations recognized as a regulatory asset and/or AOCI (before tax)

Arising this period:

Net loss	\$60,968	\$46,742	\$10,942	\$5,463	\$3,816	\$20,805
----------	----------	----------	----------	---------	---------	----------

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

Amortization of net loss	(43,745)	(47,783)	(11,938)	(6,460)	(9,358)	(10,415)
--------------------------	----------	----------	----------	---------	---------	----------

Total	\$17,223	(\$1,041)	(\$996)	(\$997)	(\$5,542)	\$10,390
-------	----------	-----------	---------	---------	-----------	----------

Total recognized as net periodic pension (income)/ cost, regulatory asset, and/or AOCI (before tax)

	\$54,824	\$46,031	\$8,514	\$4,596	(\$540)	\$21,198
--	----------	----------	---------	---------	---------	----------

Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year

Net loss	\$46,560	\$49,417	\$12,213	\$6,632	\$9,241	\$11,857
----------	----------	----------	----------	---------	---------	----------

2015	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	\$26,646	\$34,396	\$7,929	\$3,395	\$6,582	\$7,827
--	----------	----------	---------	---------	---------	---------

Interest cost on projected benefit obligation	61,885	69,465	18,007	8,432	17,414	13,970
---	--------	--------	--------	-------	--------	--------

Expected return on assets	(80,102)	(90,803)	(24,420)	(10,899)	(24,887)	(18,271)
---------------------------	----------	----------	----------	----------	----------	----------

Recognized net loss	54,254	59,802	14,896	8,053	12,950	13,055
---------------------	--------	--------	--------	-------	--------	--------

Net pension cost	\$62,683	\$72,860	\$16,412	\$8,981	\$12,059	\$16,581
------------------	----------	----------	----------	---------	----------	----------

Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)

Arising this period:

Net (gain)/loss	\$16,687	\$16,618	\$6,329	\$1,853	(\$4,488)	\$101
-----------------	----------	----------	---------	---------	-----------	-------

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

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
--	---	---------------------------------------	----------------------------------

NOTES TO FINANCIAL STATEMENTS (Continued)

Non-current liabilities	(\$375,088)	(\$419,959)	(\$96,707)	(\$52,149)	(\$47,197)	(\$109,617)
Amounts recognized as regulatory asset						
Net loss	\$706,783	\$701,324	\$191,877	\$96,913	\$145,412	\$185,774
Amounts recognized as AOCI (before tax)						
Net loss	\$—	\$44,765	\$—	\$—	\$—	\$—

2016	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	\$1,400,511	\$1,564,710	\$408,604	\$191,064	\$383,627	\$311,542
Service cost	20,724	28,194	6,250	2,625	5,664	6,263
Interest cost	52,219	59,478	15,245	7,256	14,228	11,966
Actuarial loss	62,187	48,357	11,343	5,573	4,274	20,661
Benefits paid	(81,331)	(76,506)	(22,241)	(9,054)	(21,427)	(15,051)
Balance at December 31	\$1,454,310	\$1,624,233	\$419,201	\$197,464	\$386,366	\$335,381
Change in Plan Assets						
Fair value of assets at January 1	\$959,618	\$1,071,234	\$292,297	\$129,975	\$298,378	\$212,006
Actual return on plan assets	80,306	89,998	24,325	10,858	24,705	17,692
Employer contributions	82,999	84,421	19,968	10,709	15,920	20,497
Benefits paid	(81,331)	(76,506)	(22,241)	(9,054)	(21,427)	(15,051)
Fair value of assets at December 31	\$1,041,592	\$1,169,147	\$314,349	\$142,488	\$317,576	\$235,144
Funded status	(\$412,718)	(\$455,086)	(\$104,852)	(\$54,976)	(\$68,790)	(\$100,237)
Amounts recognized in the balance sheet (funded status)						
Non-current liabilities	(\$412,718)	(\$455,086)	(\$104,852)	(\$54,976)	(\$68,790)	(\$100,237)
Amounts recognized as regulatory asset						
Net loss	\$701,774	\$686,337	\$189,409	\$94,944	\$153,544	\$169,897
Amounts recognized as AOCI (before tax)						
Net loss	\$—	\$51,660	\$—	\$—	\$—	\$—

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Accumulated Pension Benefit Obligation

The qualified pension accumulated benefit obligation for each of the Registrant Subsidiaries for their employees as of December 31, 2017 and 2016 was as follows:

	December 31,	
	2017	2016
	(In Thousands)	
Entergy Arkansas	\$1,492,876	\$1,379,265
Entergy Louisiana	\$1,652,939	\$1,513,884
Entergy Mississippi	\$430,268	\$396,081
Entergy New Orleans	\$205,316	\$186,247
Entergy Texas	\$387,083	\$365,251
System Energy	\$359,258	\$315,131

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.

Entergy uses a December 31 measurement date for its postretirement benefit plans.

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, and Entergy Texas have received regulatory approval to recover accrued other postretirement benefit 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 benefit costs collected in rates into external trusts. System Energy is funding, on behalf of Entergy Operations, other postretirement benefits associated with Grand Gulf.

Trust assets contributed by participating Registrant Subsidiaries are in master trusts, established by Entergy Corporation and maintained by a trustee. Each participating Registrant Subsidiary holds a beneficial interest in the trusts' assets. The assets in the master trusts are commingled for investment and administrative purposes. Although

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 2017, 2016, and 2015 other postretirement benefit costs of the Registrant Subsidiaries, including amounts capitalized and deferred, for their employees included the following components:

2017	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
Other postretirement costs:						
Service cost - benefits earned during the period	\$3,451	\$6,373	\$1,160	\$567	\$1,488	\$1,278
Interest cost on APBO	9,020	12,101	2,759	1,874	4,494	2,236
Expected return on assets	(15,836)	—	(4,801)	(4,635)	(8,720)	(2,869)
Amortization of prior service credit	(5,110)	(7,735)	(1,823)	(745)	(2,316)	(1,513)
Recognized net loss	4,460	1,859	1,675	418	3,303	1,560
Net other postretirement benefit (income)/cost	(\$4,015)	\$12,598	(\$1,030)	(\$2,521)	(\$1,751)	\$692
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net (gain)/loss	(29,534)	(1,256)	506	(7,342)	(22,255)	(5,459)
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of prior service credit	5,110	7,735	1,823	745	2,316	1,513

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Amortization of net loss	(4,460)	(1,859)	(1,675)	(418)	(3,303)	(1,560)
Total	(\$28,884)	\$4,620	\$654	(\$7,015)	(\$23,242)	(\$5,506)
Total recognized as net periodic other postretirement income/(cost), regulatory asset, and/or AOCI (before tax)	(\$32,899)	\$17,218	(\$376)	(\$9,536)	(\$24,993)	(\$4,814)
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Prior service credit	(\$5,110)	(\$7,735)	(\$1,823)	(\$745)	(\$2,316)	(\$1,513)
Net loss	\$1,154	\$1,550	\$1,508	\$137	\$823	\$932

2016	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	\$3,913	\$7,476	\$1,543	\$622	\$1,590	\$1,337
Interest cost on APBO	9,297	13,041	2,835	1,791	4,154	2,117
Expected return on assets	(17,855)	—	(5,517)	(4,617)	(9,575)	(3,257)
Amortization of prior service credit	(5,472)	(7,787)	(934)	(745)	(2,722)	(1,570)
Recognized net loss	4,256	2,926	893	146	2,148	1,149
Net other postretirement benefit (income)/cost	(\$5,861)	\$15,656	(\$1,180)	(\$2,803)	(\$4,405)	(\$224)
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	(\$1,007)	(\$4,647)	(\$6,219)	\$—	\$—	\$—

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Net (gain)/loss	3,331	(13,117)	8,715	5,717	13,378	4,997
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of prior service credit	5,472	7,787	934	745	2,722	1,570
Amortization of net loss	(4,256)	(2,926)	(893)	(146)	(2,148)	(1,149)
Total	\$3,540	(\$12,903)	\$2,537	\$6,316	\$13,952	\$5,418
Total recognized as net periodic other postretirement income/(cost), regulatory asset, and/or AOCI (before tax)	(\$2,321)	\$2,753	\$1,357	\$3,513	\$9,547	\$5,194
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Prior service credit	(\$5,110)	(\$7,739)	(\$1,824)	(\$745)	(\$2,316)	(\$1,513)
Net loss	\$4,460	\$1,859	\$1,675	\$418	\$3,303	\$1,560

2015	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	\$6,957	\$9,893	\$2,028	\$818	\$2,000	\$1,881
Interest cost on APBO	12,518	16,311	3,436	2,608	5,366	2,511
Expected return on assets	(19,190)	—	(6,166)	(4,804)	(10,351)	(3,644)
Amortization of prior service credit	(2,441)	(7,467)	(916)	(709)	(2,723)	(1,465)
Recognized net loss	5,356	7,118	860	470	2,740	1,198
Net other postretirement	\$3,200	\$25,855	(\$758)	(\$1,617)	(\$2,968)	\$481

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

benefit (income)/cost						
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	(\$18,035)	(\$1,361)	\$—	\$—	\$—	(\$644)
Net (gain)/loss	(11,978)	(47,043)	774	(5,810)	(4,907)	305
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of prior service credit	2,441	7,467	916	709	2,723	1,465
Amortization of net loss	(5,356)	(7,118)	(860)	(470)	(2,740)	(1,198)
Total	(\$32,928)	(\$48,055)	\$830	(\$5,571)	(\$4,924)	(\$72)
Total recognized as net periodic other postretirement income/(cost), regulatory asset, and/or AOCI (before tax)	(\$29,728)	(\$22,200)	\$72	(\$7,188)	(\$7,892)	\$409
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Prior service credit	(\$5,472)	(\$7,783)	(\$933)	(\$745)	(\$2,722)	(\$1,570)
Net loss	\$4,256	\$2,926	\$893	\$146	\$2,148	\$1,149

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

Other postretirement benefit obligations, plan assets, funded status, and amounts not yet recognized and

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

recognized in the Balance Sheets of the Registrant Subsidiaries as of December 31, 2017 and 2016 are as follows:

2017	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in APBO						
Balance at January 1	\$258,787	\$342,500	\$78,485	\$55,515	\$127,700	\$62,498
Service cost	3,451	6,373	1,160	567	1,488	1,278
Interest cost	9,020	12,101	2,759	1,874	4,494	2,236
Plan participant contributions	7,875	7,855	2,160	1,151	2,453	1,779
Actuarial (gain)/loss	(11,691)	(1,256)	5,858	(899)	(12,469)	(2,233)
Benefits paid	(18,497)	(22,273)	(5,823)	(4,670)	(6,980)	(4,205)
Medicare Part D subsidy received	74	89	22	10	16	28
Balance at December 31	\$249,019	\$345,389	\$84,621	\$53,548	\$116,702	\$61,381
Change in Plan Assets						
Fair value of assets at January 1	\$250,926	\$—	\$75,945	\$74,236	\$137,069	\$44,885
Actual return on plan assets	33,679	—	10,153	11,078	18,506	6,095
Employer contributions	695	14,418	(2)	3,709	3,123	570
Plan participant contributions	7,875	7,855	2,160	1,151	2,453	1,779
Benefits paid	(18,497)	(22,273)	(5,823)	(4,670)	(6,980)	(4,205)
Fair value of assets at December 31	\$274,678	\$—	\$82,433	\$85,504	\$154,171	\$49,124
Funded status	\$25,659	(\$345,389)	(\$2,188)	\$31,956	\$37,469	(\$12,257)
Amounts recognized in the balance sheet						
Current liabilities	\$—	(\$18,794)	\$—	\$—	\$—	\$—
Non-current liabilities	25,659	(326,595)	(2,188)	31,956	37,469	(12,257)
Total funded status	\$25,659	(\$345,389)	(\$2,188)	\$31,956	\$37,469	(\$12,257)
Amounts recognized in regulatory asset						
Prior service credit	(\$16,574)	\$—	(\$6,687)	(\$1,427)	(\$5,980)	(\$3,819)
Net loss	42,394	—	25,247	4,269	24,478	16,386
	\$25,820	\$—	\$18,560	\$2,842	\$18,498	\$12,567

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

**Amounts recognized in
AOCI (before tax)**

Prior service credit	\$—	(\$19,999)	\$—	\$—	\$—	\$—
Net loss	—	51,585	—	—	—	—
	<u>\$—</u>	<u>\$31,586</u>	<u>\$—</u>	<u>\$—</u>	<u>\$—</u>	<u>\$—</u>

2016	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in APBO						
Balance at January 1	\$258,900	\$356,253	\$77,382	\$51,951	\$114,582	\$57,645
Service cost	3,913	7,476	1,543	622	1,590	1,337
Interest cost	9,297	13,041	2,835	1,791	4,154	2,117
Plan amendments	(1,007)	(4,647)	(6,219)	—	—	—
Plan participant contributions	6,330	6,273	1,721	1,213	1,927	1,390
Actuarial (gain)/loss	2,453	(13,117)	8,230	4,774	12,389	4,806
Benefits paid	(21,178)	(22,893)	(7,031)	(4,852)	(6,977)	(4,818)
Medicare Part D subsidy received	79	114	24	16	35	21
Balance at December 31	<u>\$258,787</u>	<u>\$342,500</u>	<u>\$78,485</u>	<u>\$55,515</u>	<u>\$127,700</u>	<u>\$62,498</u>
Change in Plan Assets						
Fair value of assets at January 1	\$243,206	\$—	\$75,538	\$69,881	\$130,374	\$44,917
Actual return on plan assets	16,977	—	5,032	3,674	8,586	3,066
Employer contributions	5,591	16,620	685	4,320	3,159	330
Plan participant contributions	6,330	6,273	1,721	1,213	1,927	1,390
Benefits paid	(21,178)	(22,893)	(7,031)	(4,852)	(6,977)	(4,818)
Fair value of assets at December 31	<u>\$250,926</u>	<u>\$—</u>	<u>\$75,945</u>	<u>\$74,236</u>	<u>\$137,069</u>	<u>\$44,885</u>
Funded status	<u>(\$7,861)</u>	<u>(\$342,500)</u>	<u>(\$2,540)</u>	<u>\$18,721</u>	<u>\$9,369</u>	<u>(\$17,613)</u>
Amounts recognized in the balance sheet						
Current liabilities	\$—	(\$19,209)	\$—	\$—	\$—	\$—
Non-current liabilities	(7,861)	(323,291)	(2,540)	18,721	9,369	(17,613)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Total funded status	(\$7,861)	(\$342,500)	(\$2,540)	\$18,721	\$9,369	(\$17,613)
Amounts recognized in regulatory asset						
Prior service credit	(\$21,684)	\$—	(\$8,511)	(\$2,172)	(\$8,296)	(\$5,332)
Net loss	76,388	—	26,416	12,029	50,036	23,405
	\$54,704	\$—	\$17,905	\$9,857	\$41,740	\$18,073
Amounts recognized in AOCI (before tax)						
Prior service credit	\$—	(\$27,735)	\$—	\$—	\$—	\$—
Net loss	—	54,700	—	—	—	—
	\$—	\$26,965	\$—	\$—	\$—	\$—

Non-Qualified Pension Plans

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 employees for the non-qualified plans for 2017, 2016, and 2015, was as follows:

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				
2017	\$679	\$185	\$251	\$73	\$499
2016	\$1,819	\$231	\$236	\$65	\$504
2015	\$446	\$377	\$235	\$64	\$595

Included in the 2017 net periodic pension cost above are settlement charges of \$269 thousand for Entergy Arkansas related to the lump sum benefits paid out of the plan. Included in the 2016 net periodic pension cost above are settlement charges of \$1.4 million and \$1 thousand for Entergy Arkansas and Entergy Mississippi, respectively, related to the lump sum benefits paid out of the plan. Included in the 2015 net periodic pension cost above are settlement charges of \$108 thousand and \$2 thousand for Entergy Louisiana and Entergy Mississippi, respectively, related to the lump sum benefits paid out of the plan.

The projected benefit obligation for their employees for the non-qualified plans as of December 31, 2017 and 2016 was as follows:

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

2017	\$4,221	\$2,061	\$2,737	\$583	\$8,913
2016	\$3,897	\$2,134	\$2,296	\$514	\$8,665

The accumulated benefit obligation for their employees for the non-qualified plans as of December 31, 2017 and 2016 was as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
2017	\$3,825	\$2,061	\$2,250	\$519	\$8,602
2016	\$3,439	\$2,134	\$1,961	\$452	\$8,333

The following amounts were recorded on the balance sheet as of December 31, 2017 and 2016:

2017	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
Current liabilities	(\$376)	(\$231)	(\$135)	(\$21)	(\$788)
Non-current liabilities	(3,845)	(1,830)	(2,603)	(562)	(8,125)
Total funded status	(\$4,221)	(\$2,061)	(\$2,738)	(\$583)	(\$8,913)
Regulatory asset/(liability)	\$2,995	\$166	\$1,186	(\$140)	\$133
Accumulated other comprehensive income (before taxes)	\$—	\$11	\$—	\$—	\$—

2016	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
Current liabilities	(\$242)	(\$233)	(\$137)	(\$20)	(\$773)
Non-current liabilities	(3,655)	(1,901)	(2,159)	(495)	(7,892)
Total funded status	(\$3,897)	(\$2,134)	(\$2,296)	(\$515)	(\$8,665)
Regulatory asset/(liability)	\$2,914	\$175	\$876	(\$148)	(\$316)
Accumulated other comprehensive income (before taxes)	\$—	\$13	\$—	\$—	\$—

Accounting for Pension and Other Postretirement Benefits

Accounting standards require an employer to recognize in its balance sheet the funded status of its benefit

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

plans. This is measured as the difference between plan assets at fair value and the benefit obligation. Entergy uses a December 31 measurement date for its pension and other postretirement plans. Employers are to record previously unrecognized gains and losses, prior service costs, and any remaining transition asset or obligation (that resulted from adopting prior pension and other postretirement benefits accounting standards) as comprehensive income and/or as a regulatory asset reflective of the recovery mechanism for pension and other postretirement benefit costs in the Registrant Subsidiaries' respective regulatory jurisdictions. For the portion of Entergy Louisiana that is not regulated, the unrecognized prior service cost, gains and losses, and transition asset/obligation for its pension and other postretirement benefit obligations are recorded as other comprehensive income. Entergy Louisiana recovers other postretirement benefit costs on a pay-as-you-go basis and records the unrecognized prior service cost, gains and losses, and transition obligation for its other postretirement benefit obligation as other comprehensive income. Accounting standards also require that changes in the funded status be recorded as other comprehensive income and/or a regulatory asset in the period in which the changes occur.

With regard to pension and other postretirement costs, Entergy calculates the expected return on pension and other postretirement benefit plan assets by multiplying the long-term expected rate of return on assets by the market-related value (MRV) of plan assets. Entergy determines the MRV of pension plan assets by calculating a value that uses a 20-quarter phase-in of the difference between actual and expected returns. For other postretirement benefit plan assets Entergy uses fair value when determining MRV.

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 pension plans' funded status. 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy's qualified pension and postretirement weighted-average asset allocations by asset category at December 31, 2017 and 2016 and the target asset allocation and ranges for 2017 are as follows:

Pension Asset Allocation	Target	Range	Actual 2017	Actual 2016
Domestic Equity Securities	45%	37% to 53%	45%	46%
International Equity Securities	20%	16% to 24%	20%	20%
Fixed Income Securities	35%	32% to 38%	34%	33%
Other	0%	0% to 10%	1%	1%

Postretirement Asset Allocation	Non-Taxable and Taxable			
	Target	Range	Actual 2017	Actual 2016
Domestic Equity Securities	27%	22% to 32%	30%	40%
International Equity Securities	18%	13% to 23%	20%	27%
Fixed Income Securities	55%	50% to 60%	50%	33%
Other	0%	0% to 5%	0%	0%

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2017, 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 benefit 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, 2017, and December 31, 2016, 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Qualified Defined Benefit Pension Plan Trusts

2017	Level 1	Level 2	Level 3	Total
(In Thousands)				
Equity securities:				
Corporate stocks:				
Preferred	\$11,461 (b)	\$—	\$—	\$11,461
Common	663,923 (b)	34 (b)	—	663,957
Common collective trusts (c)				3,198,799
Registered investment companies	125,174 (d)	—	—	125,174
Fixed income securities:				
U.S. Government securities	— (b)	638,832 (a)	—	638,832
Corporate debt instruments	—	619,735 (a)	—	619,735
Registered investment companies (e)	45,768 (d)	2,735 (d)	—	764,251
Other	46 (f)	62,559 (f)	—	62,605
Other:				
Insurance company general account (unallocated contracts)	—	37,994 (g)	—	37,994
Total investments	\$846,372	\$1,361,889	\$—	\$6,122,808
Cash				1,508
Other pending transactions				5,179
Less: Other postretirement assets included in total investments				(58,179)
Total fair value of qualified pension assets				\$6,071,316

2016	Level 1	Level 2	Level 3	Total
(In Thousands)				
Short-term investments	\$—	\$3,610 (a)	\$—	\$3,610
Equity securities:				
Corporate stocks:				
Preferred	6,423 (b)	—	—	6,423
Common	745,715 (b)	39 (b)	—	745,754
Common collective trusts (c)				2,072,743
103-12 investment entities (h)				335,818
Registered investment companies	258,879 (d)	—	—	258,879
Fixed income securities:				
U.S. Government securities	136 (b)	370,545 (a)	—	370,681

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Corporate debt instruments	—	630,726	(a)	—	630,726
Registered investment companies (e)	35,216	(d)	2,695	(d)	— 640,836
Other	34	(f)	105,613	(f)	— 105,647
Other:					
Insurance company general account (unallocated contracts)	—		37,111	(g)	— 37,111
Total investments	<u>\$1,046,403</u>		<u>\$1,150,339</u>		<u>\$— \$5,208,228</u>
Cash					929
Other pending transactions					8,869
Less: Other postretirement assets included in total investments					<u>(46,824)</u>
Total fair value of qualified pension assets					<u>\$5,171,202</u>

Other Postretirement Trusts

2017	Level 1	Level 2	Level 3	Total
(In Thousands)				
Equity securities:				
Common collective trust (c)				\$300,139
Fixed income securities:				
U.S. Government securities	81,602	(b)	76,790	(a) — 158,392
Corporate debt instruments	—		92,869	(a) — 92,869
Registered investment companies	3,127	(d)	—	— 3,127
Other	—		45,627	(f) — 45,627
Total investments	<u>\$84,729</u>		<u>\$215,286</u>	<u>\$— \$600,154</u>
Other pending transactions				994
Plus: Other postretirement assets included in the investments of the qualified pension trust				<u>58,179</u>
Total fair value of other postretirement assets				<u>\$659,327</u>

2016	Level 1	Level 2	Level 3	Total
(In Thousands)				

Equity securities:				
Common collective trust (c)				\$368,704
Fixed income securities:				

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

U.S. Government securities	30,632	(b)	43,097	(a)	—	73,729
Corporate debt instruments	—		58,787	(a)	—	58,787
Registered investment companies	3,123	(d)	—		—	3,123
Other	—		45,389	(f)	—	45,389
Total investments	<u>\$33,755</u>		<u>\$147,273</u>		<u>\$—</u>	<u>\$549,732</u>
Other pending transactions						104
Plus: Other postretirement assets included in the investments of the qualified pension trust						<u>46,824</u>
Total fair value of other postretirement assets						<u>\$596,660</u>

- (a) Certain preferred stocks and certain fixed income debt securities (corporate, government, and securitized) are stated at fair value as determined by broker quotes.
- (b) Common stocks, certain 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. Net asset value per share of common collective trusts estimate fair value. Certain of these 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.
- (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 and estimate fair value using net asset value per share.
- (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. Accordingly, these funds are not assigned a level in the fair value table.
- (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.
- (h) 103-12 investment entities hold investments in accordance with stated objectives. The investment strategy of the investment entities is to capture the growth potential of international equity markets by replicating the performance of a specified index. 103-12 investment entities estimate fair value using net asset value as a practical expedient. Accordingly, these funds are not assigned a level in the fair value table.

Estimated Future Benefit Payments

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Based upon the assumptions used to measure Entergy's qualified pension and other postretirement benefit obligations at December 31, 2017, and including pension and other postretirement benefits attributable to estimated future employee service, Entergy expects that benefits to be paid and the Medicare Part D subsidies to be received over the next ten years for the Registrant Subsidiaries for their 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)						
2018	\$87,295	\$93,155	\$25,833	\$11,484	\$25,333	\$17,780
2019	\$87,832	\$96,060	\$25,977	\$12,202	\$25,656	\$18,566
2020	\$88,905	\$100,179	\$27,198	\$12,463	\$26,399	\$19,398
2021	\$90,278	\$103,810	\$27,508	\$13,087	\$26,756	\$20,279
2022	\$92,061	\$107,609	\$27,389	\$13,207	\$26,310	\$21,714
2023 - 2027	\$479,160	\$571,926	\$141,912	\$69,595	\$130,905	\$117,835

Estimated Future Non-Qualified Pension Benefits Payments	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	
(In Thousands)						
Year(s)						
2018		\$376	\$231	\$135	\$21	\$788
2019		\$300	\$219	\$137	\$55	\$764
2020		\$355	\$208	\$290	\$36	\$895
2021		\$310	\$196	\$192	\$39	\$723
2022		\$506	\$186	\$201	\$41	\$662
2023 - 2027		\$2,196	\$749	\$1,462	\$459	\$3,762

Estimated Future Other Postretirement Benefits Payments (before Medicare Part D Subsidy)	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Year(s)						
2018	\$15,282	\$18,962	\$4,677	\$3,954	\$6,485	\$3,246
2019	\$15,398	\$19,767	\$4,818	\$4,000	\$6,842	\$3,363
2020	\$15,349	\$20,287	\$5,043	\$3,952	\$7,101	\$3,381
2021	\$15,483	\$20,756	\$5,218	\$3,899	\$7,369	\$3,537
2022	\$15,419	\$21,250	\$5,331	\$3,800	\$7,519	\$3,595

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Entergy Arkansas, Inc.			2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Pre-65	6.95%	6.55%
Post-65	7.25%	7.25%
Ultimate rate	4.75%	4.75%
Year ultimate rate is reached and beyond:		
Pre-65	2027	2026
Post-65	2027	2026

The significant actuarial assumptions used in determining the net periodic pension and other postretirement benefit costs for 2017, 2016, and 2015 were as follows:

	<u>2017</u>	<u>2016</u>	<u>2015</u>
Weighted-average discount rate:			
Qualified pension:			
Service cost	4.75%	5.00%	4.27%
Interest cost	3.73%	3.90%	4.27%
Other postretirement:			
Service cost	4.60%	4.92%	4.23%
Interest cost	3.61%	3.78%	4.23%
Non-qualified pension:			
Service cost	3.65%	3.65%	3.61%
Interest cost	3.10%	3.10%	3.61%
Weighted-average rate of increase in future compensation levels	3.98%	4.23%	4.23%
Expected long-term rate of return on plan assets:			
Pension assets	7.50%	7.75%	8.25%
Other postretirement non-taxable assets	6.50% - 7.50%	7.75%	8.05%
Other postretirement taxable assets	5.75%	6.00%	6.25%
Assumed health care trend rate:			
Pre-65	6.55%	6.75%	7.10%
Post-65	7.25%	7.55%	7.70%
Ultimate rate	4.75%	4.75%	4.75%
Year ultimate rate is reached and beyond:			
Pre-65	2026	2024	2023
Post-65	2026	2024	2023

In 2016, Entergy refined its approach to estimating the service cost and interest cost components of qualified

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

pension, other postretirement, and non-qualified pension costs. Under the refined approach, instead of using the weighted-average obligation discount rates at the beginning of the year, 2016 service cost and interest costs' expected cash flows were discounted by the applicable spot rates. The refinement in approach was a change in accounting estimate and, accordingly, the effect was reflected prospectively. The measurement of the benefit obligation was not affected.

With respect to the mortality assumptions, Entergy used the RP-2014 Employee and Healthy Annuitant Tables (adjusted to base year 2006) with a fully generational MP-2017 projection scale, in determining its December 31, 2017 pension plans' PBOs and other postretirement benefit APBO. Entergy used the RP-2014 Employee and Healthy Annuitant Tables (adjusted to base year 2006) with a fully generational MP-2016 projection scale, in determining its December 31, 2016 pension plans' PBOs and other postretirement benefit APBO.

Entergy's health care cost trend is affected by both medical cost inflation, and with respect to capped costs, the effects of general inflation. A one percentage point change in Entergy's assumed health care cost trend rate for 2017 would have the following effects:

2017	1 Percentage Point Increase		1 Percentage Point Decrease	
	Impact on the APBO	Impact on the sum of service costs and interest cost	Impact on the APBO	Impact on the sum of service costs and interest cost
Increase/(Decrease) (In Thousands)				
Entergy Corporation and its subsidiaries	\$166,814	\$10,221	(\$139,648)	(\$8,385)

The Registrant Subsidiaries' health care cost trend is affected by both medical cost inflation, and with respect to capped costs, the effects of general inflation. A one percentage point change in the assumed health care cost trend rate for 2017 would have the following effects for the Registrant Subsidiaries for their employees:

2017	1 Percentage Point Increase		1 Percentage Point Decrease	
	Impact on the APBO	Impact on the sum of service costs and interest cost	Impact on the APBO	Impact on the sum of service costs and interest cost
Increase/(Decrease) (In Thousands)				
Entergy Arkansas	\$23,612	\$1,369	(\$19,810)	(\$1,133)
Entergy Louisiana	\$37,240	\$2,333	(\$31,063)	(\$1,909)
Entergy Mississippi	\$8,666	\$448	(\$7,276)	(\$370)
Entergy New Orleans	\$4,585	\$251	(\$3,895)	(\$208)
Entergy Texas	\$12,444	\$751	(\$10,452)	(\$618)
System Energy	\$7,334	\$475	(\$6,074)	(\$387)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 also sponsors the Savings Plan of Entergy Corporation and Subsidiaries IV (established in March 2002), the Savings Plan of Entergy Corporation and Subsidiaries VI (established in April 2007), and the Savings Plan of Entergy Corporation and Subsidiaries VII (established in April 2007) to which matching contributions are also made. The plans are defined contribution plans that cover eligible employees, as defined by each plan, of Entergy and certain of its subsidiaries.

The Registrant Subsidiaries' 2017, 2016, and 2015 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)					
2017	\$3,741	\$5,079	\$2,133	\$731	\$1,865
2016	\$3,528	\$4,746	\$1,997	\$708	\$1,778
2015	\$3,242	\$4,324	\$1,920	\$721	\$1,620

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

Each of the Registrant Subsidiaries has one reportable segment, which is an integrated utility business, except for System Energy, which is an electricity generation business. Each of the Registrant Subsidiaries' operations is 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.

NOTE 14. ACQUISITIONS, DISPOSITIONS, AND IMPAIRMENT OF LONG-LIVED ASSETS

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Acquisitions

Union Power Station

In March 2016, Entergy Arkansas, Entergy Louisiana, and Entergy New Orleans purchased the Union Power Station, a 1,980 MW (summer rating) power generation facility located near El Dorado, Arkansas, from Union Power Partners, L.P. The Union Power Station consists of four natural gas-fired, combined-cycle gas turbine power blocks, each rated at 495 MW (summer rating). Entergy Louisiana purchased two of the power blocks and a 50% undivided ownership interest in certain assets related to the facility, and Entergy Arkansas and Entergy New Orleans each purchased one power block and a 25% undivided ownership interest in such related assets. The aggregate purchase price for the Union Power Station was approximately \$949 million (approximately \$237 million for each power block and associated assets).

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, particularly power price and fuel price risk.

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 derivative 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.

Entergy's exposure to market risk is determined by a number of factors, including the size, term, composition, and diversification of positions held, as well as market volatility and liquidity. For instruments such as options, the time period during which the option may be exercised and the relationship between the current market price of the underlying instrument and the option's contractual strike or exercise price also affects the level of market risk. A significant factor influencing the overall level of market risk to which Entergy is exposed is its use of hedging techniques to mitigate such risk. Hedging instruments and volumes are chosen based on ability to mitigate risk associated with future energy and capacity prices; however, other considerations are factored into hedge product and volume decisions including corporate liquidity, corporate credit ratings, counterparty credit risk, hedging costs, firm settlement risk, and product availability in the marketplace. Entergy manages market risk by actively monitoring compliance with stated risk management policies as well as monitoring the effectiveness of its hedging policies and strategies. Entergy's risk management policies limit the amount of total net exposure and rolling net exposure during the stated periods. These policies, including related risk

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

limits, are regularly assessed to ensure their appropriateness given Entergy's objectives.

Derivatives

Some derivative instruments are classified as cash flow hedges due to their financial settlement provisions while others are classified as normal purchase/normal sale transactions due to their physical settlement provisions. Normal purchase/normal sale risk management tools include power purchase and sales agreements, fuel purchase agreements, capacity contracts, and tolling agreements. Financially-settled cash flow hedges can include natural gas and electricity swaps and options and interest rate swaps. Entergy may enter into financially-settled swap and option contracts to manage market risk that may or may not be designated as hedging instruments.

Entergy may use standardized master netting agreements to help mitigate the credit risk of derivative instruments. These master agreements facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds an established threshold. The threshold represents an unsecured credit limit, which may be supported by a parental/affiliate guaranty, as determined in accordance with Entergy's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Entergy manages fuel price volatility for its Louisiana jurisdictions (Entergy Louisiana and Entergy New Orleans) and Entergy Mississippi through the purchase of short-term natural gas swaps that financially settle against NYMEX futures. These swaps are marked-to-market through fuel expense with offsetting regulatory assets or liabilities. All benefits or costs of the program are recorded in fuel costs. The notional volumes of these swaps are based on a portion of projected annual exposure to gas for electric generation at Entergy Louisiana and Entergy Mississippi and projected winter purchases for gas distribution at Entergy Louisiana and Entergy New Orleans. The total volume of natural gas swaps outstanding as of December 31, 2017 is 38,540,750 MMBtu for Entergy, including 31,361,500 MMBtu for Entergy Louisiana, 6,714,250 MMBtu for Entergy Mississippi, and 465,000 MMBtu for Entergy New Orleans. Credit support for these natural gas swaps is covered by master agreements that do not require collateral based on mark-to-market value, but do carry adequate assurance language that may lead to requests for collateral.

During the second quarter 2017, Entergy participated in the annual financial transmission rights auction process for the MISO planning year of June 1, 2017 through May 31, 2018. Financial transmission rights are derivative instruments which 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 Entergy Wholesale Commodities 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, 2017 is 10,479 GWh for Entergy Arkansas, 20,590 GWh for Entergy

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Louisiana, 6,391 GWh for Entergy Mississippi, 2,366 GWh for Entergy New Orleans, and 6,322 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. Letters of credit posted with MISO covered the financial transmission rights exposure for Entergy Arkansas, Entergy Mississippi, and Entergy Texas as of December 31 2017 and for Entergy Arkansas and Entergy Mississippi as of December 31, 2016.

The fair values of the Registrant Subsidiaries' derivative instruments not designated as hedging instruments on their balance sheets as of December 31, 2017 and 2016 are as follows:

Instrument	Balance Sheet Location	Fair Value (a)	Registrant
(In Millions)			
2017			
Assets:			
Financial transmission rights	Prepayments and other	\$3.0	Entergy Arkansas
Financial transmission rights	Prepayments and other	\$10.2	Entergy Louisiana
Financial transmission rights	Prepayments and other	\$2.1	Entergy Mississippi
Financial transmission rights	Prepayments and other	\$2.2	Entergy New Orleans
Financial transmission rights	Prepayments and other	\$3.4	Entergy Texas
Liabilities:			
Natural gas swaps	Other current liabilities	\$5.0	Entergy Louisiana
Natural gas swaps	Other current liabilities	\$1.2	Entergy Mississippi
Natural gas swaps	Other current liabilities	\$0.2	Entergy New Orleans
2016			
Assets:			
Natural gas swaps	Prepayments and other	\$10.9	Entergy Louisiana
Natural gas swaps	Prepayments and other	\$2.3	Entergy Mississippi
Natural gas swaps	Prepayments and other	\$0.2	Entergy New Orleans
Financial transmission rights	Prepayments and other	\$5.4	Entergy Arkansas
Financial transmission rights	Prepayments and other	\$8.5	Entergy Louisiana
Financial transmission rights	Prepayments and other	\$3.2	Entergy Mississippi
Financial transmission rights	Prepayments and other	\$1.1	Entergy New Orleans
Financial transmission rights	Prepayments and other	\$3.1	Entergy Texas

(a) As of December 31, 2017, letters of credit posted with MISO covered financial transmission rights exposure of \$0.2 million for Entergy Arkansas, \$0.1 million for Entergy Mississippi, and \$0.05 million for Entergy Texas.

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

As of December 31, 2016, letters of credit posted with MISO covered financial transmission rights exposure of \$0.3 million for Entergy Arkansas and \$0.1 million for Entergy Mississippi.

The effects of the Registrant Subsidiaries' derivative instruments not designated as hedging instruments on their income statements for the years ended December 31, 2017, 2016, and 2015 are as follows:

Instrument	Income Statement Location	Amount of gain (loss) recorded in the income statement (In Millions)	Registrant
2017			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$25.4)	(a) Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$5.2)	(a) Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$0.3)	(a) Entergy New Orleans
Financial transmission rights	Purchased power	\$41.7	(b) Entergy Arkansas
Financial transmission rights	Purchased power	\$45.8	(b) Entergy Louisiana
Financial transmission rights	Purchased power	\$18.9	(b) Entergy Mississippi
Financial transmission rights	Purchased power	\$9.1	(b) Entergy New Orleans
Financial transmission rights	Purchased power	\$22.3	(b) Entergy Texas
2016			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	\$8.4	(a) Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	\$3.1	(a) Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$0.4)	(a) Entergy New Orleans
Financial transmission rights	Purchased power	\$23.2	(b) Entergy Arkansas
Financial transmission rights	Purchased power	\$69.7	(b) Entergy Louisiana
Financial transmission rights	Purchased power	\$16.6	(b) Entergy Mississippi

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Financial transmission rights	Purchased power	\$4.1	(b) Entergy New Orleans
Financial transmission rights	Purchased power	\$10.2	(b) Entergy Texas

2015

Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$33.2)	(a) Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$6.1)	(a) Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(\$1.4)	(a) Entergy New Orleans
Financial transmission rights	Purchased power	\$68.7	(b) Entergy Arkansas
Financial transmission rights	Purchased power	\$55.4	(b) Entergy Louisiana
Financial transmission rights	Purchased power	\$16.5	(b) Entergy Mississippi
Financial transmission rights	Purchased power	\$8.5	(b) Entergy New Orleans
Financial transmission rights	Purchased power	\$16.8	(b) Entergy Texas

- (a) Due to regulatory treatment, the natural gas swaps 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 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.

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 other than those instruments held by the Entergy Wholesale Commodities business 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 hedge contracts. 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.

- 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 and derivative power contracts used as cash flow hedges of power sales at merchant power plants.

The values of financial transmission rights are based on unobservable inputs, including estimates of congestion

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 Business Unit Risk Control group. The values are calculated internally and verified against the data published by MISO. Entergy's Accounting Policy and Entergy Wholesale Commodities 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 Business Unit Risk Control groups report to the Vice President and Treasurer. The Accounting Policy and Entergy Wholesale Commodities Accounting group reports to the Chief Accounting Officer.

The following table sets forth, by level within the fair value hierarchy, the Registrant Subsidiaries' assets that are accounted for at fair value on a recurring basis as of December 31, 2017 and December 31, 2016. The assessment of the significance of a particular input to a fair value measurement requires judgment and may affect its placement within the fair value hierarchy levels.

Entergy Arkansas

2017	Level 1	Level 2	Level 3	Total
(In Millions)				
Assets:				
Decommissioning trust funds (a):				
Equity securities	\$11.7	\$—	\$—	\$11.7
Debt securities	115.8	232.4	—	348.2
Common trusts (b)				585.0
Securitization recovery trust account	3.7	—	—	3.7
Escrow accounts	2.4	—	—	2.4
Financial transmission rights	—	—	3.0	3.0
	\$133.6	\$232.4	\$3.0	\$954.0

2016	Level 1	Level 2	Level 3	Total
(In Millions)				
Assets:				
Decommissioning trust funds (a):				
Equity securities	\$3.6	\$—	\$—	\$3.6
Debt securities	112.5	196.8	—	309.3
Common trusts (b)				521.8
Securitization recovery trust account	4.1	—	—	4.1
Escrow accounts	7.1	—	—	7.1
Financial transmission rights	—	—	5.4	5.4

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

\$127.3 \$196.8 \$5.4 \$851.3

- (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 9 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 derivatives classified as Level 3 in the fair value hierarchy for the year ended December 31, 2017.

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Millions)				
Balance as of January 1,	\$5.4	\$8.5	\$3.2	\$1.1	\$3.1
Issuances of financial transmission rights	8.9	31.0	9.6	5.0	7.1
Gains (losses) included as a regulatory liability/asset	30.4	16.5	8.2	5.2	15.5
Settlements	(41.7)	(45.8)	(18.9)	(9.1)	(22.3)
Balance as of December 31,	<u>\$3.0</u>	<u>\$10.2</u>	<u>\$2.1</u>	<u>\$2.2</u>	<u>\$3.4</u>

The following table sets forth a reconciliation of changes in the net assets (liabilities) for the fair value of derivatives classified as Level 3 in the fair value hierarchy for the year ended December 31, 2016.

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Millions)				
Balance as of January 1,	\$7.9	\$8.5	\$2.4	\$1.5	\$2.2
Issuances of financial transmission rights	18.8	18.1	5.9	2.8	9.3
Gains included as a regulatory liability/asset	1.9	51.6	11.5	0.9	1.8
Settlements	(23.2)	(69.7)	(16.6)	(4.1)	(10.2)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Balance as of December 31, \$5.4 \$8.5 \$3.2 \$1.1 \$3.1

NOTE 16. DECOMMISSIONING TRUST FUNDS

Entergy holds debt and equity securities, classified as available-for-sale, in nuclear decommissioning trust accounts. The NRC requires Entergy subsidiaries to maintain trusts to fund the costs of decommissioning ANO 1, ANO 2, River Bend, Waterford 3, and Grand Gulf. The funds are invested primarily 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, the Registrant Subsidiaries have recorded an offsetting amount of unrealized gains/(losses) on investment securities in other regulatory liabilities/assets. Generally, Entergy records realized 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 debt and equity securities, classified as available-for-sale, in nuclear decommissioning trust accounts. The securities held as of December 31, 2017 and 2016 are summarized as follows:

	2017			2016		
	Fair Value	Total Unrealized Gains	Total Unrealized Losses	Fair Value	Total Unrealized Gains	Total Unrealized Losses
	(In Millions)					
Equity Securities	\$596.7	\$354.9	\$—	\$525.4	\$281.5	\$—
Debt Securities	348.2	2.1	3.0	309.3	3.4	4.2
Total	\$944.9	\$357.0	\$3.0	\$834.7	\$284.9	\$4.2

The amortized cost of debt securities was \$349.1 million as of December 31, 2017 and \$310.1 million as of December 31, 2016. As of December 31, 2017, the debt securities have an average coupon rate of approximately 2.64%, an average duration of approximately 5.61 years, and an average maturity of approximately 7.00 years. The equity securities are generally held in funds that are designed to approximate the return of the Standard & Poor's 500 Index. A relatively small percentage of the equity securities are held in funds intended to replicate the return of the Wilshire 4500 Index.

The fair value and gross unrealized losses of available-for-sale equity and debt securities, summarized by investment type and length of time that the securities have been in a continuous loss position, are as follows as of December 31, 2017 and 2016:

2017

2016

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

	Equity Securities		Debt Securities		Equity Securities		Debt Securities	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	(In Millions)							
Less than 12 months	\$—	\$—	\$168.0	\$1.2	\$—	\$—	\$146.7	\$4.2
More than 12 months	—	—	41.4	1.8	—	—	—	—
Total	\$—	\$—	\$209.4	\$3.0	\$—	\$—	\$146.7	\$4.2

The fair value of debt securities, summarized by contractual maturities, as of December 31, 2017 and 2016 are as follows:

	2017	2016
	(In Millions)	
less than 1 year	\$13.0	\$16.7
1 year - 5 years	123.4	106.2
5 years - 10 years	180.6	161.2
10 years - 15 years	4.8	7.7
15 years - 20 years	3.4	1.0
20 years+	23.0	16.5
Total	\$348.2	\$309.3

During the years ended December 31, 2017, 2016, and 2015, proceeds from the dispositions of securities amounted to \$339.4 million, \$197.4 million, and \$213 million, respectively. During the years ended December 31, 2017, 2016, and 2015, gross gains of \$17.7 million, \$1.8 million, and \$5.9 million, respectively, and gross losses of \$0.6 million, \$0.8 million, and \$0.3 million, respectively, were recorded in earnings.

Other-than-temporary impairments and unrealized gains and losses

Entergy evaluates investment securities in the Entergy Wholesale Commodities' nuclear decommissioning trust funds with unrealized losses at the end of each period to determine whether an other-than-temporary impairment has occurred. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether Entergy has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. Further, if Entergy does not expect to recover the entire amortized cost basis of the debt security, an other-than-temporary impairment is considered to have occurred and it is measured by the present value of cash flows expected to be collected less the amortized cost basis (credit loss). Entergy did not have any material other-than-temporary impairments relating to credit losses on debt securities for the years ended December 31, 2017, 2016, and 2015. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment is based on a number of factors including, first, whether Entergy has the ability and intent to hold the

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

investment to recover its value, the duration and severity of any losses, and, then, whether it is expected that the investment will recover its value within a reasonable period of time. 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. Entergy did not record material charges to other income in 2017, 2016, or 2015 resulting from the recognition of the other-than-temporary impairment of equity securities held in its decommissioning trust funds.

NOTE 17. VARIABLE INTEREST ENTITIES

Note 17 to the financial statements is not applicable to the presentation in 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.

As described in Note 1 to the financial statements, all of System Energy's operating revenues consist of billings to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans.

As described in Note 4 to the financial statements, the Registrant Subsidiaries participate in Entergy's money pool and earn interest income from the money pool.

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)					
2017	\$127.8	\$282.4	\$1.7	\$—	\$57.9	\$633.5
2016	\$49.4	\$376.6	\$2.9	\$30.3	\$180.2	\$548.3
2015	\$127.9	\$420.2	\$86.0	\$66.1	\$259.1	\$632.4

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>
--	-----------------------------	------------------------------	--------------------------------	------------------------------------	--------------------------	--------------------------

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	(In Millions)					
2017	\$510.2	\$619.5	\$310.5	\$286.1	\$234.6	\$197.0
2016	\$467.4	\$670.8	\$256.5	\$276.7	\$343.7	\$146.0
2015	\$508.5	\$929.4	\$331.8	\$278.4	\$413.7	\$155.1

NOTE 19. SUBSEQUENT EVENTS

Management has evaluated the impact of events occurring after December 31, 2017 up to April 16, 2018, the date that Entergy Arkansas's FERC financial statements and disclosures were filed. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	10,406,401,151	10,406,401,151
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	734,709,538	734,709,538
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	11,141,110,689	11,141,110,689
9	Leased to Others		
10	Held for Future Use	965,381	965,381
11	Construction Work in Progress	293,919,423	293,919,423
12	Acquisition Adjustments	44,516,241	44,516,241
13	Total Utility Plant (8 thru 12)	11,480,511,734	11,480,511,734
14	Accum Prov for Depr, Amort, & Depl	4,681,668,737	4,681,668,737
15	Net Utility Plant (13 less 14)	6,798,842,997	6,798,842,997
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,310,374,129	4,310,374,129
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	362,762,361	362,762,361
22	Total In Service (18 thru 21)	4,673,136,490	4,673,136,490
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	178,367	178,367
29	Amortization		
30	Total Held for Future Use (28 & 29)	178,367	178,367
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	8,353,880	8,353,880
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,681,668,737	4,681,668,737

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 200 Line No.: 21 Column: c

Consists of accumulated provision for amortization of intangible assets.

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)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	54,283,106	4,892,849
4	Allowance for Funds Used during Construction	4,903,070	-753,134
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	59,186,176	
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)	229,909,367	56,429,625
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	-18,256,483	-7,085,908
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	307,352,026	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
		59,175,955	3
		4,149,936	4
			5
		63,325,891	6
			7
			8
			9
			10
			11
93,388,039		192,950,953	12
-4,273,943		-21,068,448	13
		277,345,292	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 202 Line No.: 12 Column: b

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

Investment of River Fuel Trust #1 at December 31, 2017

Investment at December 31, 2016	\$229,909,367
Additional investment in fuel	54,594,253
Daily lease charges allocated to and included in capitalized costs	1,835,372
Less: Burn-up charges paid to lessor	93,388,039

Total Investment at December 31, 2017	\$192,950,953
	=====

Cost Incurred under River Fuel Trust #1 Lease for the
Year Ended December 31, 2017

Daily Lease Charges	\$5,285,025
Fuel Burn-Up Charges	93,388,039

Total	\$98,673,064
	=====

As of December 31, 2017, arrangements to lease nuclear fuel existed in an aggregate amount up to \$210 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 May 16, 2019. The intermediate-term notes issued pursuant to these fuel lease arrangements have varying maturities through December 15, 2023. 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.

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	33,366	
3	(302) Franchises and Consents	3,832,306	
4	(303) Miscellaneous Intangible Plant	408,047,261	46,791,779
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	411,912,933	46,791,779
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,128,299	
9	(311) Structures and Improvements	67,728,498	790,430
10	(312) Boiler Plant Equipment	462,624,019	22,012,608
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	140,823,413	505,465
13	(315) Accessory Electric Equipment	59,604,236	594,929
14	(316) Misc. Power Plant Equipment	13,581,191	101,092
15	(317) Asset Retirement Costs for Steam Production	4,355,712	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	750,845,368	24,004,524
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,648,089	
19	(321) Structures and Improvements	561,910,024	1,516,607
20	(322) Reactor Plant Equipment	1,267,071,019	152,270,810
21	(323) Turbogenerator Units	343,025,972	7,244,706
22	(324) Accessory Electric Equipment	316,674,033	44,554,419
23	(325) Misc. Power Plant Equipment	298,515,685	32,441,054
24	(326) Asset Retirement Costs for Nuclear Production	110,910,357	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	2,900,755,179	238,027,596
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,304,416	
28	(331) Structures and Improvements	2,893,498	95,017
29	(332) Reservoirs, Dams, and Waterways	15,011,802	833,675
30	(333) Water Wheels, Turbines, and Generators	20,576,249	1,655,226
31	(334) Accessory Electric Equipment	3,524,981	160,367
32	(335) Misc. Power PLant Equipment	2,218,499	
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production	7,341	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	45,536,786	2,744,285
36	D. Other Production Plant		
37	(340) Land and Land Rights	5,182,173	144
38	(341) Structures and Improvements	408,594,394	1,744,732
39	(342) Fuel Holders, Products, and Accessories	5,514,481	328,277
40	(343) Prime Movers	152,850,355	19,431,252
41	(344) Generators	344,325,769	766,672
42	(345) Accessory Electric Equipment	15,343,650	1,940,896
43	(346) Misc. Power Plant Equipment	3,613,536	408,446
44	(347) Asset Retirement Costs for Other Production	23,762	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	935,448,120	24,620,419
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,632,585,453	289,396,824

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	62,635,536	3,252,164
49	(352) Structures and Improvements	75,395,879	-1,484,815
50	(353) Station Equipment	873,101,094	153,922,820
51	(354) Towers and Fixtures	143,169,658	788,708
52	(355) Poles and Fixtures	434,739,970	36,724,656
53	(356) Overhead Conductors and Devices	412,973,143	4,752,723
54	(357) Underground Conduit	18,865	
55	(358) Underground Conductors and Devices	64,477	106,698
56	(359) Roads and Trails	1,899,889	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,003,998,511	198,062,954
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	8,925,615	391,253
61	(361) Structures and Improvements	26,418,076	1,743,392
62	(362) Station Equipment	440,500,557	21,687,609
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	619,957,325	33,933,273
65	(365) Overhead Conductors and Devices	581,482,181	43,874,688
66	(366) Underground Conduit	103,886,337	4,486,828
67	(367) Underground Conductors and Devices	160,089,536	7,287,545
68	(368) Line Transformers	803,924,085	42,889,590
69	(369) Services	286,428,119	5,133,746
70	(370) Meters	128,064,086	1,433,256
71	(371) Installations on Customer Premises	42,858,880	1,614,159
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	89,795,039	6,412,866
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,292,329,836	170,888,205
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,309,753	
87	(390) Structures and Improvements	128,541,382	7,864,676
88	(391) Office Furniture and Equipment	18,719,854	6,477,794
89	(392) Transportation Equipment		233,749
90	(393) Stores Equipment	878,382	
91	(394) Tools, Shop and Garage Equipment	15,347,171	1,342,240
92	(395) Laboratory Equipment	1,222,958	503,274
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	41,344,781	4,809,961
95	(398) Miscellaneous Equipment	4,021,547	50,900
96	SUBTOTAL (Enter Total of lines 86 thru 95)	218,385,828	21,282,594
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)	218,385,828	21,282,594
100	TOTAL (Accounts 101 and 106)	10,559,212,561	726,422,356
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)	10,559,212,561	726,422,356

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				1
			33,366	2
			3,832,306	3
			454,839,040	4
			458,704,712	5
				6
				7
			2,128,299	8
443,334		-130,921	67,944,673	9
6,402,363			478,234,264	10
				11
104,813			141,224,065	12
148,557			60,050,608	13
137,327			13,544,956	14
			4,355,712	15
7,236,394		-130,921	767,482,577	16
				17
		-6,782	2,641,307	18
387,950			563,038,681	19
4,735,253			1,414,606,576	20
4,302,018			345,968,660	21
993,851			360,234,601	22
2,068,564			328,888,175	23
			110,910,357	24
12,487,636		-6,782	3,126,288,357	25
				26
			1,304,416	27
			2,988,515	28
			15,845,477	29
			22,231,475	30
1,526			3,683,822	31
			2,218,499	32
				33
			7,341	34
1,526			48,279,545	35
				36
			5,182,317	37
522,356			409,816,770	38
			5,842,758	39
1,212,564			171,069,043	40
-1,972,181			347,064,622	41
673,283			16,611,263	42
15,795			4,006,187	43
			23,762	44
451,817			959,616,722	45
20,177,373		-137,703	4,901,667,201	46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
			65,887,700	48
14,673			73,896,391	49
5,704,984		2,737,874	1,024,056,804	50
242,521			143,715,845	51
2,044,557			469,420,069	52
631,516		-55,606	417,038,744	53
			18,865	54
			171,175	55
			1,899,889	56
				57
8,638,251		2,682,268	2,196,105,482	58
				59
		6,782	9,323,650	60
12,213			28,149,255	61
1,372,580		27,463	460,843,049	62
				63
32,393,151			621,497,447	64
20,516,696			604,840,173	65
3,814,716			104,558,449	66
6,158,138			161,218,943	67
31,185,639			815,628,036	68
3,977,375			287,584,490	69
14,547			129,482,795	70
365,498			44,107,541	71
				72
8,870,368			87,337,537	73
				74
108,680,921		34,245	3,354,571,365	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
-29,500			8,339,253	86
1,106,196		130,921	135,430,783	87
2,452,885			22,744,763	88
			233,749	89
50,630			827,752	90
800,897			15,888,514	91
			1,726,232	92
				93
1,972,880		-2,709,731	41,472,131	94
673,695			3,398,752	95
7,027,683		-2,578,810	230,061,929	96
				97
				98
7,027,683		-2,578,810	230,061,929	99
144,524,228			11,141,110,689	100
				101
				102
				103
144,524,228			11,141,110,689	104

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 49 Column: c

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

Schedule Page: 204 Line No.: 104 Column: d

The negative retirements represent a correction of retirement adjustments recorded in the preceding year.

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Little Rock Ne 500kv Transmission Substation	1974		283,835
3	Land and Land Rights Under \$250,000	Various		461,392
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Other Property Under \$250,000	Various		220,154
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			965,381

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	UG SECONDARY DIPS FOR LRAFB - PHASE	1,061,779
3	HIGHWAY: RELOCATE FACILITIES FOR HI	643,112
4	IMPROVEMENT: JOINT T&D SUBSTATION H	636,354
5	REIMB-HWY RELOC. PROJ CA0202	616,585
6	N411 RECONDUCTOR--WEINER--HB17-001V	522,987
7	MANDATED OVERHEAD: AHTD PROJECT 061	458,524
8	IMP.-C388 RECONDUCTOR FOR MA17-004V	437,702
9	HARRISBURG: IMPROVEMENT FOR WELL LO	401,539
10	IMPROVEMENT: GLEN CKT Y204 - HS17-0	384,495
11	IMPROVEMENT-RECONDUCTOR CIRCUIT-WOO	356,766
12	BACKBONE-A180-MONROE AVE	352,057
13	IMPROVEMENT: H.S. ROYAL CKT Z452 -	345,994
14	GRIFFITHVILLE-P701-RECONDUCTOR	340,094
15	Planned project SR16-011A Feeder: P	334,854
16	HIGHWAY-RELOCATE UG FAC (HWY 425-HA	325,610
17	IMPROVE: LOAD JUSTIFICATION ALBRIGH	302,310
18	RS17-014V - Replace 2.4 miles of 1/	301,619
19	CONVERT OH TO UG FOR LRAFB PHASE 2F	247,996
20	BACKBONE INSPECTION CIRCUIT N530 PR	239,873
21	MC17-008T FOCUS L439 23420	229,543
22	FOCUS-2017-A173-COLUMBIA 11	228,472
23	MANDATED OVERHEAD: AHTD PROJECT CA0	219,312
24	MANDATED OVERHEAD AHTD 050280	202,852
25	New Circuit for Deltic Timber	188,052
26	GARLAND-GAINES NETWORK TIE	169,908
27	MANDATED OVERHEAD: AHTD PROJECT 050	163,209
28	SR17-003V N456 Reconductor Hwy 11 3	158,299
29	REVENUE: NEW 795 CIRCUIT FROM SUB T	157,283
30	RS17-008V REPLACE #6 CU WITH 2PHAS	152,110
31	A119; RECONDUCTOR FOR OVERLOAD AND	141,083
32	RS16-003A - REPLACE 0.62 MILES OF #	139,840
33	RS16-002A - SUMMER - BUILD NEW CIRC	135,468
34	P513 replace 1 #4 ACSR conductor on	135,023
35	CW16-005A - Summer - Add 1/0 ACSR o	130,653
36	OTHER DISTRIBUTION PLANT	1,287,198
37		
38	GENERAL & INTANGIBLE PLANT:	
39	CDR Digital Assets Software/Implemt	8,971,234
40	ANO2 Implement License Renewal Comm	6,671,776
41	AMI - DMS/OMS - Software	5,229,817
42	EAM - Meters - Software	4,320,716
43	TOTAL	293,919,423

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	AMI Electric Meters PMO/Impl.	4,211,369
2	AMI - Legacy systems - Software	4,055,732
3	AMI - IT Systems Integration	3,688,641
4	CDR Case mgmt/CRM Software/Impl	3,305,292
5	AMI - MDMS Software	3,088,902
6	Purchase of West Markham Building	2,598,394
7	HR Reporting - Project EMEE	2,249,634
8	Cust Digital IVR Software/Implement	2,189,817
9	AMI-Entrprs Servc Bus-Softwre R1 R2	1,968,790
10	AMI - Head End Software & Hardware	1,953,916
11	CD&I Grid Modernization Grid Study	1,516,357
12	AMI - DMS/OMS - Infrastructure	1,378,666
13	AMI-Comm. Network-PMO/Impl.	1,212,917
14	Syntempo/Maxavera Work Flow Tool	1,182,838
15	AMI Regulatory Support - EAI	1,181,677
16	CIP-014 Physical Security Impl.	1,013,526
17	Harrison Service Center Purchase	976,409
18	Software - Alert Enterprise	957,162
19	McGehee SC Renovation	933,623
20	SW-Trans Asset Renewal and Maint	919,161
21	Pine Bluff SC Roof Replacement	884,568
22	AMI - DMS/OMS - Software- EMS/SCADA	805,214
23	EI Dorado SC Improvements	719,700
24	Enterprise Analytics	679,229
25	Purchase of West Markham Land	649,599
26	AMI - DMS/OMS - Software - PI	608,936
27	AMI - MDMS Software Licences - Elec	569,435
28	Grid Modernization: EAM Project	549,260
29	Purchase of McGehee SC - Building	494,899
30	Searcy SC Improvements	491,729
31	AMI - MDMS Infrastructure	483,713
32	DAR-Utility GETAC Ruggedizd Tab	422,065
33	Wynne Service Center Purchase	409,760
34	AMI-EnterpriseServiceBus-Infrastruc	385,062
35	Active Directory Forest	355,800
36	Magnolia Service Center Purchase	337,081
37	AMI - Head End Infrastructure	307,103
38	SW1- Windows 10 Upgrade	278,998
39	Cust Digital IVR Hardware	267,216
40	Harrison SC - Land Purchase	242,101
41	Crossett Service Center Purchase	239,496
42	Infra Disaster Recov Automation	228,981
43	TOTAL	293,919,423

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	DNV - Radio Enhancements	217,073
2	EAM - Meters - Infrastructure	174,542
3	CDR Digital Assets Hardware	172,686
4	SW2 - EDE-Bill Syst Contr Repo Inte	171,037
5	Tools	147,072
6	PROJECT CIRCE CBLE	144,901
7	SAP Info Lifecycle Mgmt	139,113
8	CIPv6 Little Rock Data Center	133,746
9	Service Center Standards AR	125,611
10	AR Grid; purchase doble test set	124,361
11	Purchase McGehee SC Land	120,564
12	Learning Management	117,976
13	SW3-EDE-Bill Syst Contr Repo Integr	115,767
14	EA GETACS FOR AR	115,373
15	CIPv6 Jackson Data Center	112,680
16	Bill Print Vendor Replacement	109,300
17	Wynne SC - Land Purchase	107,869
18	AMI - Legacy Systems-Infrastructure	105,692
19	SW - Middleware- Weblogic Phase 2	103,518
20	OTHER GENERAL & INTANGIBLE PLANT	1,964,283
21		
22	PRODUCTION PLANT:	
23	ANO1 Mods resulting from NFPA 805	15,810,468
24	U1 Replace Pressurizer Heater Bundl	9,744,076
25	ANO Dry Fuel Storage (2017 Campaign	6,422,977
26	ANO2 A600 Surface Peening of RVH Pe	5,903,482
27	ANOC SPING Replacement	5,686,526
28	AN1 NFPA805 Common Feedwater - Inst	5,640,233
29	ANC Tornado Missile Msnry Wall Upgr	4,495,432
30	ANC Reroof & Seal Wall at RERTC Bld	3,811,364
31	WB1 Low Nox Burners/SOFA System	3,667,358
32	ANO-2 CEDM Purchase	3,017,080
33	ANO Dry Fuel Storage (2019 Campaign	2,751,330
34	WB1 CAVR Scrubber,Stack,Burners	2,260,654
35	ANC Mechanic and Weld Shop Upgrades	2,229,536
36	WB2 CAVR Scrubber,Stack,Burners	2,228,977
37	AN1 Upgr Electr Maintenance Shop	2,148,312
38	ANO1 EFW Terry Turbine K-3 Gov Repl	2,114,914
39	AN1 B0125 - Breaker Replacement	2,014,575
40	1R27 NFPA 805 WORK	2,009,816
41	ANO2 Underground piping replacement	1,873,630
42	ANC Training Center Improvements	1,706,014
43	TOTAL	293,919,423

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	ANO1 BMI Penetration Mitigation	1,512,013
2	AN1 Purchase Spare N9000 RCP seals	1,337,990
3	ANC NAOCL/NABR Injection System	1,145,041
4	ANO1 SW Piping Replacement 1R27	1,129,144
5	ANO2 Cooling Tower Refurbishment	1,086,117
6	ANC Purchase Stud Tensioners - Refu	1,035,842
7	AN1 P-32B/C/D Seal Replacements	932,434
8	WB1 Unit 1 Absorber Area	931,265
9	ANC Reroof Maint Facility Area 1	914,947
10	ANO1 ICW Heat Exchanger 'C' replace	886,851
11	WB1 Unit 1 Baghouse	879,254
12	ANC Repl Evapco Cooling Twr @ GSB	830,567
13	WB2 Unit 2 Baghouse	819,241
14	WBC Reagent Prep System	803,691
15	WB2 Unit 2 Absorber Area	738,196
16	AN1 Replace P-32A RCP Motor	728,583
17	AN1 DH-17/18 Valve Replacement	714,092
18	1R27 Refurbish and install reheat s	708,303
19	2P-7B U2 EFW New Motor Purchase	687,063
20	Declaratory Order for WB Scrubber	592,159
21	AN2 2K-3 EFW Drainline Project	574,343
22	UPC - Water Pretreatment System	573,444
23	AN2 Reroof Turbine/Aux Bldg Area 4	538,514
24	ANO1 Underground Piping Replacement	526,050
25	ANO1 1R28 SW Piping Repl	504,242
26	WB2 Flue Gas System	436,409
27	WB1 Flue Gas System	430,842
28	ANC Scoping Study for Fire Sys Repl	402,108
29	AN1 EDG Exhaust Stack Mod	399,070
30	WBC DCS (FGD units)	381,961
31	AN1 2R26 2K-4A EDG Governor Repl	347,988
32	CIPv6 Hot Spring Power Block 1	336,829
33	AN1 Repl VE-1A Condenser	334,772
34	ANO1 RX-7460 Skid Repl/Electro Upgr	325,188
35	WB1 Booster Fans	316,933
36	WB2 Booster Fans	316,933
37	CIPv6 Lake Cahterine (S)	297,836
38	AN2 Repl 2VUC-27B Cooling Coils	290,309
39	AN1 RV Flange Leak Offline Repl.	288,630
40	AN2 2K-2B MFP TURB ROTOR 2R26	275,442
41	ANO2 RVLMS Obsolete Equip	232,693
42	ANO Recovery Plan Site Roof Replace	222,654
43	TOTAL	293,919,423

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	AN2 Repl CPC Chillers 2VUC-37A&B	220,508
2	AN2B0126 - 22kV Breaker Replacement	211,112
3	AN1 Modify MS-271 & MS-272 Valves	210,259
4	ANO1 Upgrade Main Steam Safety Vlv	203,159
5	Fossil EAI PO Ouachita Common	165,494
6	ANC Engin Supp for Obsolescence	165,471
7	ANO2 Main Refueling Bridge Upgrade	164,325
8	UP2 - Condensate Filtration System	156,072
9	AN2 2R26 SIT Target Rock Valve Upgr	145,278
10	P-36A, High Pressure Injection pump	125,248
11	AN1 1R27 Repl MOOG & MFWP HP Valves	122,787
12	ANO2 Spare SS Wet End for SW Pump	118,601
13	AN1 Refurb P-1A/B Spare Rot Asmbly	115,928
14	AN1 1R27 CV-2630/2680 Part 21 Issue	114,468
15	WBC Leachate Pumping Station	113,748
16	AN2 2017 Dixson Sigma Indicator Rep	111,332
17	AN2 Repl 2M-76 Instrument Air Dryer	104,235
18	CIPv6 REMMEL HYDRO	104,004
19	CIPv6 CARPENTER HYDRO	103,280
20	OTHER PRODUCTION PLANT	1,566,384
21		
22	TRANSMISSION & DISTRIBUTION SUBSTATION PLANT:	
23	CamdenMag 115kV: Reconfig	4,790,529
24	Newark: Add 2nd XFMR	3,885,672
25	Corning 115kV Substation	3,315,560
26	LR Kanis Install 33MVA Xfmr	3,230,255
27	MabelvaleAT2:Rplce 500kV Autos 2018	3,015,140
28	CIPv6 EAI Transmission Subs 2017	2,608,245
29	Green Forest South-Add Xfmr	2,077,009
30	Marked Tree; replace 2 breakers	1,970,857
31	Texas Eastern 110 kV #8 (Customer)	1,924,461
32	Jonesboro 161kV Upg Terminal Equip	1,222,712
33	Datto 161/151kV Substation	1,150,412
34	Newport Build New SS & Line	1,042,712
35	MacArthur Land Acquisition	830,326
36	AR El Dorado; Security Plan	653,336
37	AR KEO; Security Plan	562,743
38	Pecan St Bld New 161kV Sub	542,258
39	Pleasant Hill Add Reactor Bank	500,747
40	Jim Hill Sub Convert to 161kV	491,273
41	Tarleton: Build 230kV Sub	484,720
42	London North: Build New Sub	473,863
43	TOTAL	293,919,423

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	Purchase (1) Spare 500kV breaker	461,275
2	Newpot Relay and Telecom upgrades	439,084
3	Bsmrk 115/13.8kV: HS Rplc Rely Pan	395,844
4	Rohwer - Rpl Xfmr	388,234
5	Mabelvale: Replace 500kV Autos	378,274
6	AR White Bluff; Security Plan	375,178
7	AR Dell; Security Plan	372,795
8	ANO-MabV Term Equip Upgr_MVP	369,244
9	AR Sheridan; Security Plan	290,428
10	AR ISES; Security Plan	283,224
11	EI Dor Add 2nd 500/115 kV auto	245,772
12	Jacksonville North B3621 Rplc	228,640
13	LR Walton Heights; failed LTC #2	227,375
14	Arkadelphia N. replace 2 switches	208,248
15	Fisher; failed T1 diff panel & CT's	206,739
16	EAI - Circuit Replacement - MSC	204,452
17	ANO; replac Auto relay panel	191,474
18	EI Dor Donan Add 30 MVAR Cap 115kV	175,051
19	Marked Tree; rplc 4 failed switches	174,884
20	Jacksonville North; B2336 & B5036	172,158
21	WHITEBLUFF - PRC002	166,044
22	Thayer S.; rebuild breakers	149,589
23	West Helena-Install Breakers	142,631
24	AR Grid; fld relay panel T20-1	140,938
25	CIPv6 EAI Distribution Subs 2017	136,448
26	Mabelvale Remote End Relay	136,310
27	England; failed bypass switches	132,220
28	Blytheville I55; failed CS heads	130,685
29	NLR McCain Sub Expansion	123,100
30	Newport AB; rplc B5549 w/FV LBS	120,147
31	AR Mabelvale; Security Plan	114,121
32	EL DORADO - PRC002	108,467
33	ISES Repl 500/161kV AutoXFMRs	107,098
34	OTHER TRANSMISSION & DISTRIBUTION SUB	2,973,115
35		
36	TRANSMISSION LINES PLANT:	
37	Monticello East/Reed New 115kV Line	20,334,444
38	Newport to Mallory Cut in Rebuild	3,405,369
39	Corning to Texas Eastern #8 Rbldg	3,363,255
40	AECC Corning N to Corning Ln Rldg	3,012,989
41	Datto- AECC Corning N Convert 161kV	2,212,075
42	EI Dor E-EI Dor Jxn Rbld Line 115kV	813,156
43	TOTAL	293,919,423

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	Cut In Nwprt-Wnut Rdg	369,881
2	Texas Eastern #8- State Ln Rbldg	335,923
3	Minor Add to WO# C6PPTLA161	318,988
4	State Ln -Jim Hill Conv to 161kV	229,520
5	Mayflwr-Morgan Rebuild Line 115kV	217,972
6	LR West - LR Gaines, Rpl Strs	211,988
7	AECC Nimrod Sub New POD 115kV	186,073
8	CAMMAg T-Lin 952 Repl Shldng 115kV	148,773
9	MacArthur New Sub Cut-In 115kV	121,936
10	Mabelvale to Bryant South Rebild Ln	120,515
11	OTHER TRANSMISSION LINES	959,672
12		
13	UNDISTRIBUTED OVERHEADS:	2,812,318
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	293,919,423

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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), 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.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	4,251,996,713	4,251,818,346	178,367	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	248,022,989	248,022,989		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,141,881	2,141,881		
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					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	250,164,870	250,164,870		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	144,524,228	144,524,228		
13	Cost of Removal	48,561,846	48,561,846		
14	Salvage (Credit)	1,506,487	1,506,487		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	191,579,587	191,579,587		
16	Other Debit or Cr. Items (Describe, details in footnote):	-29,500	-29,500		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,310,552,496	4,310,374,129	178,367	

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	577,061,250	577,061,250		
21	Nuclear Production	1,580,218,836	1,580,218,836		
22	Hydraulic Production-Conventional	16,312,491	16,301,100	11,391	
23	Hydraulic Production-Pumped Storage				
24	Other Production	468,325,262	468,325,262		
25	Transmission	495,610,099	495,532,442	77,657	
26	Distribution	1,099,171,858	1,099,171,858		
27	Regional Transmission and Market Operation				
28	General	73,852,700	73,763,381	89,319	
29	TOTAL (Enter Total of lines 20 thru 28)	4,310,552,496	4,310,374,129	178,367	

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 3 Column: c

Excludes service company depreciation allocations of \$7,587,987 (included in the depreciation expense shown on page 336), since these allocations do not offset to accumulated depreciation reserves.

Schedule Page: 219 Line No.: 16 Column: c

Net (Gain)/Loss closed to Accumulated Reserve of (\$29,500).

Schedule Page: 219 Line No.: 20 Column: c

Includes a debit balance of \$1,313,824 for asset retirement obligations.

Schedule Page: 219 Line No.: 21 Column: c

Includes a credit balance of \$71,738,372 for asset retirement obligations.

Schedule Page: 219 Line No.: 22 Column: c

Includes a debit balance of \$27,866 for asset retirement obligations.

Schedule Page: 219 Line No.: 24 Column: c

Includes credit balance of \$12,639 for asset retirement obligations.

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	The Arklahoma Corporation			
2	Common Stock - 238 shares	5/16/47		64,872
3	Equity in Earnings - 47.6% Ownership			133,535
4	Subtotal			198,407
5				
6	System Fuels, Inc.			
7	Common Stock - 70 shares	1/4/72		110,250
8	Subtotal			110,250
9				
10	Entergy Arkansas Restoration Funding, LLC	6/17/10		
11	Capital Contribution			620,600
12	Undistributed retained earnings			-1,853,957
13	Subtotal			-1,233,357
14				
15	Arkansas Power & Light Company			
16	Capital Contribution			5,733,787
17	Undistributed retained earnings			-4,526,772
18	Subtotal			1,207,015
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	282,315

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

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)	Line No.
				1
		64,872		2
		133,535		3
		198,407		4
				5
				6
		110,250		7
		110,250		8
				9
				10
		620,600		11
558,900	-3,849	-1,298,906		12
558,900	-3,849	-678,306		13
				14
				15
	-103,963	5,629,824		16
-431,761		-4,958,533		17
-431,761	-103,963	671,291		18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
127,139	-107,812	301,642		42

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)	28,412,584	25,428,706	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	4,346,544	3,888,517	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	124,604,188	134,866,982	Electric
8	Transmission Plant (Estimated)	20,356,111	20,128,153	Electric
9	Distribution Plant (Estimated)	18,469,164	19,178,231	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	163,429,463	174,173,366	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	19,170,388	18,679,357	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	215,358,979	222,169,946	

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	121,554.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	32,667.00		30,346.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Prior Year Adjustment	91.00			
10					
11					
12					
13					
14					
15	Total	91.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Allowances Used	15,663.00			
23					
24					
25					
26					
27					
28	Total	15,663.00			
29	Balance-End of Year	138,649.00		30,346.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA	472.00		472.00	
38	Deduct: Returned by EPA				
39	Cost of Sales	472.00		472.00	
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	472.00	37		
45	Gains		37		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

- 6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
- 7. Report on Lines 8-14 the names of vendors/transfersors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
- 8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
- 9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
- 10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						121,554.00		1
								2
								3
30,346.00		30,346.00		819,355.00		943,060.00		4
								5
								6
								7
								8
						91.00		9
								10
								11
								12
								13
								14
						91.00		15
								16
								17
								18
								19
								20
								21
						15,663.00		22
								23
								24
								25
								26
								27
						15,663.00		28
30,346.00		30,346.00		819,355.00		1,049,042.00		29
								30
								31
								32
								33
								34
								35
								36
472.00		472.00		12,748.00		14,636.00		37
								38
472.00		472.00		12,748.00		14,636.00		39
								40
								41
								42
								43
						472.00		37 44
								37 45
								46

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 4 Column: j

Future years include allowances issued from 2021 through 2047.

Schedule Page: 228 Line No.: 37 Column: j

Future years include allowances issued from 2021 through 2047.

Schedule Page: 228 Line No.: 39 Column: j

Future years include allowances issued from 2021 through 2047.

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	1,155.00	566		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	3,575.00		2,642.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10	Purc not bill to CoOwners	102.00	40,800		
11					
12					
13					
14					
15	Total	102.00	40,800		
16					
17	Relinquished During Year:				
18	Charges to Account 509	3,668.88	439		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,163.12	40,927	2,642.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transfersors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						1,155.00	566	1
								2
								3
2,642.00		2,642.00		5,284.00		16,785.00		4
								5
								6
								7
								8
						102.00	40,800	9
								10
								11
								12
								13
								14
						102.00	40,800	15
								16
								17
						3,668.88	439	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
2,642.00		2,642.00		5,284.00		14,373.12	40,927	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 229 Line No.: 4 Column: j

Future years include allowances issued from 2021 through 2022.

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised 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	TOTAL					

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

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					
21	Generation Studies				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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 the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Income Taxes	85,432,864	857,088,603	282,283	942,521,467	
2						
3	Grand Gulf 1 Costs Rider - Under-Recovery	9,613,643	17,527,575			27,141,218
4						
5	Deferred Fuel Under-Recovery	18,726,518	44,522,466			63,248,984
6						
7	Capacity Costs Recovery Rider - Under-Recovery	466,041	597,143			1,063,184
8						
9	TCA/Ice Storm Settlement - Docket No. 01-296-U					
10	and Docket No. 01-084-U, Amort 30 years	7,899,864		407.3	526,656	7,373,208
11						
12	Asset Retirement Obligation - Coal	335,380	231,687			567,067
13						
14	Asset Retirement Obligation - Nuclear	316,266,956	21,626,882			337,893,838
15						
16	Asset Retirement Obligation - Fossil	6,048,570	333,889			6,382,459
17						
18	Asset Retirement Obligation - Hydro	59,584	3,368			62,952
19						
20	Asset Retirement Obligation - Other	232,366	14,587			246,953
21						
22	Defined Benefit Pension and Other					
23	Postretirement Plans	786,591,608	22,661,824	(1)	52,296,973	756,956,459
24						
25	Deferred Storm Restoration Costs					
26	APSC Docket No. 09-031-U	47,727,411		(2)	110,638	47,616,773
27						
28	Federal Litigation Consulting Fees	1,060,393	127,470			1,187,863
29						
30	MISO implementation costs APSC Docket No.					
31	10-011-U Order No. 76. Amort thru Dec 2018	11,098,580		(3)	5,549,290	5,549,290
32						
33	MISO Financial Transmission Rights Mark-to-Market	2,341,345	2,172,151	242	3,829,724	683,772
34						
35	Human Capital Management cost deferral					
36	APSC Docket No. 13-028-U, Order No. 21					
37	recover thru retail rates thru August 2019	7,036,069		(4)	2,638,526	4,397,543
38						
39	MOARK Agreement - APSC Docket No. 13-028-U					
40	Order No. 21. Amort period 20 year eff Jan 2014	7,365,899		566	433,288	6,932,611
41						
42						
43						
44	TOTAL	1,479,735,751	1,080,116,445		1,091,875,569	1,467,976,627

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 the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Lake Catherine 4 Reliability & Sustainability Costs					
2	APSC Docket No. 15-015-U - Amortization					
3	10 years beg March 2016	9,844,285	185,149	(5)	1,174,333	8,855,101
4						
5	System Agreement Costs Under Collection	1,766,515		431,557	1,713,080	53,435
6						
7	Replacement Energy Fuel					
8	APSC Docket No. 13-028-U Order No. 23	66,897,675	197,957			67,095,632
9						
10	ANO Flood Barrier Costs - APSC Docket No. 15-015-U					
11	Order No. 18, Amort 10 years thru Feb 2026	9,116,422		(6)	994,519	8,121,903
12						
13	ANO Fukushima Costs - APSC Docket No. 15-015-U					
14	Order No. 18, Amort 10 years thru Feb 2026	7,017,000		(7)	765,491	6,251,509
15						
16	Opportunity Sales FERC Docket No. EL09-61-002	76,197,178	2,981,945	182.3	79,179,123	
17						
18	Opportunity Sales FERC Docket No. EL09-61-006		109,843,749			109,843,749
19						
20	2015 Rate Case Deferral - APSC Docket No. 15-015-U					
21	Order No. 18, Amort 5 years thru Feb 2021	593,585		(8)	142,461	451,124
22						
23	(1) 107, 926, 190, 410.1, 411.1					
24						
25	(2) 924, 593, 571, 407.3					
26						
27	(3) 408.1, 500, 510, 556, 557, 560, 561.5,					
28	562, 566, 905, 920, 921, 923, 925, 926, 928,					
29	930.2, 931, 935, 403, 407.3					
30						
31	(4) 500, 506, 517, 524, 546, 560, 580, 907,					
32	920, 921, 923, 549, 566, 588, 931, 935, 408.1,					
33	926					
34						
35	(5) 403, 500, 506, 510, 512, 513, 514					
36						
37	(6) 517, 520, 524, 525, 528, 530, 532					
38						
39	(7) 403, 517, 520, 524, 525, 528, 530, 531,					
40	532, 920, 923					
41						
42	(8) 403, 923, 926, 928, 930.1					
43						
44	TOTAL	1,479,735,751	1,080,116,445		1,091,875,569	1,467,976,627

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)
				Account Charged (d)	Amount (e)	
1	Non-Expense Accrued Labor	1,435,496	235,822			1,671,318
2						
3	Section 263A	896,318		930.2	73,632	822,686
4						
5	Securitization Financing Costs					
6	Docket 10-008-U					
7	Amort pd 8/18/10-8/1/21	95,002		930.2	20,728	74,274
8						
9	Agric Irrig AMI Load Control					
10	Docket 08-072-TF	9,542,902	498,293	930.2	1,125,592	8,915,603
11						
12	Pooled Equipment - PEICo	1,608,337		517	83,221	1,525,116
13						
14	Other	57,421	20,648	930.2	3,527	74,542
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	13,635,476				13,083,539

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 of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	See Footnote Detail	219,563,378	310,918,865
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	219,563,378	310,918,865
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	219,563,378	310,918,865

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 2 Column: a

	BALANCE AT BEG OF YEAR	BALANCE AT END OF YEAR
Interest/Tax Deficiencies	\$73,352	\$48,873
ANO Shutdown Costs	(355,812)	(146,745)
Grand Gulf 1 - Over/Under Recovery	(3,770,951)	(7,093,357)
Taxable Unbilled Revenue	6,798,743	6,194,986
Property Insurance Reserve	(13,573,938)	(5,070,444)
Capitalized Repairs	665,471	554,442
Injuries & Damages Reserve	1,471,352	1,269,858
Pension Plan	(124,274,239)	(100,291,476)
Defined Benefit Pension	297,870,850	192,248,172
Supplemental Pension Plan	385,609	320,250
Post-Employment Benefits	(27,384,467)	(18,548,967)
Deferred Fuel	(14,774,137)	(16,530,122)
Removal Cost	(13,516,248)	(38,501,256)
Acquisition	-	(2,954,070)
Asset Retirement Obligation	150,542	(74,443)
Accrued Medical Claims	2,917,926	2,296,867
Uncollectible Accounts	475,054	277,844
Partnership Income/Loss	(4,094)	(2,728)
Contract Deferred Revenue	4,438	1,186
Environmental Reserve	709,580	432,273
Incentive Compensation	1,891,831	2,077,456
Long-Term Incentive Compensation	105,320	92,205
Stock Options	547,998	219,490
Restricted Stock Awards	241,528	140,667
Deferred Directors' Fees	285	35,982
Rate Refund	600,815	619,268
Sale of EPA Allowances	15	30
Reorganization Costs	9,347,540	7,408,432
Income Tax Adjustment	22,786,382	266,557,914
ADIT-Cont. Carryforward	414,400	499,469
ADIT-Tax CR Carryforward	2,074,182	2,677,584
Fed Offset-St Carryover	(1,819,597)	(12,455)
ADIT NOL Carryforward	69,503,648	16,171,680
	-----	-----
TOTAL	\$219,563,378	\$310,918,865
	=====	=====

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.

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)
1	ACCOUNT 201: Common Stock			
2	Common - par value	325,000,000	0.01	
3	Total Account 201: Common Stock	325,000,000		
4				
5	ACCOUNT 204: Preferred Stock			
6	4.32% Preferred - Cumulative	70,000	100.00	103.65
7	4.72% Preferred - Cumulative	93,500	100.00	107.00
8	4.56% Preferred - Cumulative	75,000	100.00	102.83
9	4.56% Preferred - 1965 Series Cumulative	75,000	100.00	102.50
10	Total Account 204: Preferred Stock	313,500		
11				
12				
13	Unissued Series:			
14	\$100 par value	3,416,500		
15	\$25 par value	9,000,000		
16	\$.01 par value	15,000,000		
17	Total unissued	27,416,500		
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- 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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
46,980,196	469,802					2
46,980,196	469,802					3
						4
						5
70,000	7,000,000					6
93,500	9,350,000					7
75,000	7,500,000					8
75,000	7,500,000					9
313,500	31,350,000					10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

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

Line No.	Item (a)	Amount (b)
1	ACCOUNT 208: Donations Received from Stockholders - None	
2		
3	ACCOUNT 209: Reduction in Par or Stated Value of Capital Stock	
4	From \$12.50 to \$0.01 (1987)	586,782,648
5		
6	ACCOUNT 210: Gain on Resale or Cancellation of Reacquired	
7	Capital Stock - None	
8		
9	ACCOUNT 211: Miscellaneous Paid-in-Capital - None	200,000,000
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	786,782,648

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2017/Q4</u>
--	---	---------------------------------------	--

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	Capital Stock Expense - Common Stock	49,710
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	49,710

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - BONDS - MORTGAGE BONDS:		
2	3.75% Series	350,000,000	2,518,954
3			101,500 D
4	4.9% Series	200,000,000	6,777,506
5			
6	3.05% Series	250,000,000	1,989,735
7			705,000 D
8	4.75% Series	125,000,000	4,151,566
9			
10	3.70% Series	375,000,000	3,081,212
11			270,000 D
12	4.95% Series	250,000,000	2,430,691
13			1,780,000 D
14	3.5% Series	325,000,000	2,575,894
15			1,069,250 D
16	3.5% Series	55,000,000	796,158
17			-4,565,000 P
18	3.5% Series	220,000,000	1,904,240
19			-4,857,600 P
20	4.875% Series	410,000,000	12,358,529
21			
22	TOTAL ACCOUNT 221	2,560,000,000	33,087,635
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,659,700,000	34,090,293

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 224 - OTHER LONG-TERM DEBT:		
2	POLLUTION CONTROL BONDS:		
3	Independence County 2.375% Series 2013	45,000,000	508,717
4			
5	Jefferson County 1.55% Series 2013	54,700,000	493,941
6			
7	SOLID WASTE DISPOSAL BONDS:		
8	Department of Energy (Nuclear Fuel Disposal Cost)		
9			
10	LONG-TERM OBLIGATIONS:		
11	Little Rock Air Force Base distribution facilities 4.2%		
12			
13	TOTAL ACCOUNT 224	99,700,000	1,002,658
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,659,700,000	34,090,293

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
11/12/2010	02/15/2021	11/12/2010	02/15/2021	350,000,000	13,125,000	2
						3
12/13/2012	12/01/2052	12/13/2012	12/01/2052	200,000,000	9,800,000	4
						5
05/30/2013	06/01/2023	05/30/2013	06/01/2023	250,000,000	7,625,000	6
						7
06/04/2013	06/01/2063	06/04/2013	06/01/2063	125,000,000	5,937,500	8
						9
03/14/2014	06/01/2024	03/14/2014	06/01/2024	375,000,000	13,875,000	10
						11
12/09/2014	12/15/2044	12/09/2014	12/15/2044	250,000,000	12,375,000	12
						13
01/08/2016	04/01/2026	01/08/2016	04/01/2026	325,000,000	11,375,000	14
						15
06/16/2016	04/01/2026	06/16/2016	04/01/2026	55,000,000	1,925,000	16
						17
05/16/2017	04/01/2026	05/16/2017	04/01/2026	220,000,000	4,812,500	18
						19
08/16/2016	09/01/2066	08/16/2016	09/01/2066	410,000,000	19,987,500	20
						21
				2,560,000,000	100,837,500	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,790,477,180	104,204,731	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
01/09/2013	01/01/2021	01/09/2013	01/01/2021	45,000,000	1,068,750	3
						4
01/09/2013	10/01/2017	01/09/2013	10/01/2017		629,757	5
						6
						7
				183,435,340	1,582,603	8
						9
						10
				2,041,840	86,121	11
						12
				230,477,180	3,367,231	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,790,477,180	104,204,731	33

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 1 Column: i

Total interest for Accounts 221 and 224 is recorded in Account 427, as shown on page 117, line 62.

Schedule Page: 256 Line No.: 18 Column: a

Mortgage Bonds 3.5% Series reopened May 16, 2017, to issue an additional \$220,000,000.

Schedule Page: 256.1 Line No.: 5 Column: h

Jefferson County, Arkansas 1.55% Pollution Control Revenue Refunding Bonds matured October 1, 2017.

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)	139,843,883
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote Detail	15,530,226
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote Detail	126,796,183
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote Detail	9,621,265
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote Detail	352,517,174
21		
22		
23	Other Reconciling Items	
24	See Footnote Detail	67,682,605
25		
26		
27	Federal Tax Net Income	-12,285,542
28	Show Computation of Tax:	
29	Normal and Surtax @ 35%	-4,299,940
30		
31	Estimated Consolidated Income Tax Allocated	
32	See Footnote Detail	
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Recorded on Books:	
Avoided Cost - Tax Interest	\$3,680,714
Contributions in Aid of Construction	4,958,515
Deferred Contract Revenue	(6,775)
EPA Allowances	37
Gain or Loss on Sale of Property	(37)
Other Misc Taxable Items	526,656
Unbilled Revenue	6,371,116

Total	\$15,530,226
	=====

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted for Return:	
Accrual of Reserves	\$20,673,352
Coal Car Lease	2,215,409
Deferred Compensation and Benefits	4,873,504
Dry Cask Amortization	4,273,943
Asset Retirement Obligation	(65,978)
Meals and Entertainment	303,130
Nuclear Fuel Burn	93,388,039
Other Misc Expenses Not Deducted in Return	13,408
Penalties	270,178
Political Expenses	1,148,000
Rate Refund	837,782
Reserve for Uncollectible Accounts	(147,991)
Securitization	(986,593)

Total	\$126,796,183
	=====

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded on Books Not Included in Return:	
Allowance for Funds Used During Construction	\$9,057,815
Equity Earnings in Subs	563,450

Total	\$9,621,265
	=====

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged Against Book Income:	
Amortization of Regulatory Assets	(\$11,492,502)
Bond Reacquisition Loss	(3,274,398)
Daily Lease Charges	1,835,372
Deferred Fuel	62,247,999
Depletion	17,827
Depreciation of Nuclear Fuel	82,726,890
Depreciation of Plant Assets	371,206,099
EOI/ESI Billings	14,825,820
IRC Sec 475 Mark to Market Adjustments	(229,497,000)
Outage Costs	(25,174,330)
Pension and OPEB	69,867,096
Prepaid Expenses	(630,614)
Research and Development Costs	(2,567,000)
Software Costs	6,297,000
Supplier Refund	31,933,492
UOP Repairs	(16,548,577)
Vegetation Management	6,000
Warranty Expense	738,000

Total	\$352,517,174
	=====

Schedule Page: 261 Line No.: 24 Column: b

Reconciling Items for the Year:	
Net Operating Loss	(\$25,309,099)
Federal Income Tax Accrual - Current year	(4,299,939)
Federal Income Tax Accrual - Prior year	19,967,942
Investment Tax Credit	(1,225,968)
FIN 48 taxes	(35,555,299)
Provision for Deferred Income Tax	105,784,951
State Income Tax Accrual - Prior Year	6,399,725
Provision for FERC decision in Docket EL-09-61	1,920,292

Total	\$67,682,605
	=====

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Energy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 32 Column: a

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 2017. 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 Arkansas, Inc.	(\$4,144,000)
Entergy Utility Assets Holdings, LLC	2,097,000
Entergy Mississippi, Inc.	(4,662,000)
Entergy New Orleans, Inc.	(3,654,000)
System Energy Resources, Inc.	46,894,000
Entergy Services, Inc.	7,169,000
System Fuels, Inc.	13,000
Entergy Operations, Inc.	3,674,000
Entergy Corporation	(55,762,000)
Entergy Solutions LLC	(5,000)
Entergy Nuclear Generation Company	(24,174,000)
Entergy Nuclear Holding Company #3, LLC	(41,669,000)
Entergy Nuclear Vermont Investment Company, LLC	(1,867,000)
Entergy Power Marketing Holding II, Inc.	(1,801,000)
Entergy Nuclear, Inc.	(436,000)
Entergy Nuclear Holding Company #1	(9,553,000)
TLG Services, Inc.	(35,000)
Entergy Nuclear Operations, Inc.	33,860,000
Entergy Nuclear Fuels Company	(6,000)
Entergy Power Holdings, Inc.	6,582,000
EAM Nelson Holdings, LLC	330,000
Entergy Nighthawk GP, LLC	2,037,000
Entergy Power Investment Holdings, Inc.	(7,000)
Entergy Mississippi Turbine Company	(119,000)
Entergy Nuclear Holding Company #2	488,000
Entergy Power, LLC	(255,000)
Entergy Enterprises, Inc.	174,000
Entergy Power Gas Operations LLC	23,092,000
Entergy Power Marketing Holding I, Inc.	(12,534,000)
GSG&T, Inc.	(260,000)
Entergy Power Operations U.S., Inc.	392,000
Entergy Nuclear Palisades, LLC	(11,181,000)
EK Holding III, LLC	(7,000)
Entergy Utility Affiliates Holdings, LLC	(6,000)
EWO Marketing, LLC	(555,000)
Entergy Texas, Inc.	9,896,000
Entergy Global LLC	6,837,000
Entergy Utility Assets, LLC	19,323,000
Arkansas Power & Light Company LLC	44,000
Entergy Nuclear Vermont Finance Co.	(5,000)
Entergy Technologies Company	253,000
Warren Power, LLC	(44,000)
Entergy Asset Management, Inc.	9,903,000
Entergy Investment Holding Company	(6,000)
EWO Wind II, LLC	(311,000)
Total	----- \$- =====

TAXES ACCRUED, PREPAID AND CHARGED 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES:					
2	Federal Income Tax	57,204,829		-24,135,929	-8,105,000	
3	FICA	1,269,959		9,459,895	9,327,222	
4	Federal Unemployment Tax	-791,910		58,989	57,380	
5	Federal Excise Tax			10,403	10,403	
6	Subtotal	57,682,878		-14,606,642	1,290,005	
7						
8	STATE & LOCAL TAXES:					
9	State Income Tax	-19,106,268		8,537,311	-557,005	
10	State Unemployment Tax	457,869		307,373	306,944	
11	Capital Stock Franchise	2,178		150,511	152,689	
12	Regulatory Commission		1,793,123	3,573,503	3,533,455	
13	Use Tax	2,454,216		23,051,742	21,137,311	
14	Gross Receipts & Sales Tax	9,624		159,337	87,080	
15	Railcar	18,461		54,306	57,181	
16	Gross Receipts Privilege Tax					
17	Ad Valorem Tax	40,422,074		47,419,847	41,028,110	
18	Franchise Tax - Local	6,498,929		41,872,307	40,277,858	
19	State Excise Tax			73,791	73,791	
20	Non Income Tax	187,000				
21	Subtotal	30,944,083	1,793,123	125,200,028	106,097,414	
22						
23	Payroll Loading Tax					
24						
25	Taxes Other Than					
26	Income Taxes					
27	Entergy Services, Inc.					
28						
29						
30	Income Taxes					
31	Entergy Services, Inc.					
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	88,626,961	1,793,123	110,593,386	107,387,419	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
41,173,900		-41,471,524			17,335,595	2
1,402,633		3,929,890			5,530,005	3
-790,301		24,453			34,536	4
		10,403				5
41,786,232		-37,506,778			22,900,136	6
						7
						8
-10,011,952		5,030,045			3,507,266	9
458,298		41,573			265,800	10
		152,689			-2,178	11
	1,753,075	3,573,503				12
4,368,647					23,051,742	13
81,881		159,337				14
15,586					54,306	15
		22			-22	16
46,813,811		41,481,242			5,938,605	17
8,093,378		42,017,994			-145,687	18
		73,791				19
187,000						20
50,006,649	1,753,075	92,530,196			32,669,832	21
						22
						23
						24
						25
						26
		11,947,914			-11,947,914	27
						28
						29
						30
		4,272,071			-4,272,071	31
						32
						33
						34
						35
						36
						37
						38
						39
						40
91,792,881	1,753,075	71,243,403			39,349,983	41

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)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	20,745			411.4	17,737	
4	7%						
5	10%	35,284,350			411.4	1,183,547	
6							
7							
8	TOTAL	35,305,095				1,201,284	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
3,008	60 Years		3
			4
34,100,803	60 Years		5
			6
			7
34,103,811			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 266 Line No.: 3 Column: i

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

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	Unfunded Pension Expense	412,717,572	131,107,926	89,198,059	51,568,700	375,088,213
2						
3	Supplemental Pension Plan	3,655,474	241,232,131	436,951	626,079	3,844,602
4						
5	Long-term Incentive Plan	268,503	131,207	151,849	236,148	352,802
6						
7	Unrecoverable costs - EAI Rate					
8	Case Settlement - Docket 09-84-U	38,567,962	426.5	824,274	6,099,207	43,842,895
9						
10	Non IPP Advances	70,986	107,421	1,057		69,929
11						
12	Ouachita gas yard	789,457	501	629,389		160,068
13						
14	Restricted Unit Program	68,360			68,360	136,720
15						
16	Other	55,252	131,923	14,918		40,334
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	456,193,566		91,256,497	58,598,494	423,535,563

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2017/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
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			

NOTES

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,861,826,372	647,491,495	565,864,712
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,861,826,372	647,491,495	565,864,712
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,861,826,372	647,491,495	565,864,712
10	Classification of TOTAL			
11	Federal Income Tax	1,618,061,944	594,076,756	525,040,175
12	State Income Tax	243,764,428	53,414,739	40,824,537
13	Local Income Tax			

NOTES

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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
		182.3	685,010,320			1,258,442,835	2
							3
							4
			685,010,320			1,258,442,835	5
							6
							7
							8
			685,010,320			1,258,442,835	9
							10
		182.3	684,866,454			1,002,232,071	11
		182.3	143,866			256,210,764	12
							13

NOTES (Continued)

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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	See Footnote Detail	462,420,783	154,033,069	279,264,886
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	462,420,783	154,033,069	279,264,886
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	462,420,783	154,033,069	279,264,886
20	Classification of TOTAL			
21	Federal Income Tax	385,792,738	140,633,907	245,103,238
22	State Income Tax	76,628,045	13,399,162	34,161,648
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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
							2
		Footnote	363,431,417	190	224,000,107	197,757,656	3
							4
							5
							6
							7
							8
			363,431,417		224,000,107	197,757,656	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			363,431,417		224,000,107	197,757,656	19
							20
		Footnote	300,571,617	190	168,289,348	149,041,138	21
		Footnote	62,859,800	190	55,710,759	48,716,518	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: a

	BALANCE AT BEGINNING OF YEAR	CHANGES DURING YEAR			
		AMOUNTS DEBITED TO ACCT. 410.1	AMOUNTS CREDITED TO ACCT. 411.1	AMOUNTS DEBITED TO ACCT. 410.2	AMOUNTS CREDITED TO ACCT. 411.2
Reg Asset-Securitization	\$ 27,428,191	\$ 1,432,120	\$ 14,385,151	\$ -	\$ -
Reg Asset-MISO	4,353,418	245,695	3,148,806	-	-
Replace Energy Fuel	26,240,613	692,722	9,397,892	-	-
System Equalization Agrmt	23,152,599	22,269,864	16,700,834	-	-
Maint/Refueling Reserve	31,895,108	59,955,533	77,088,416	-	-
Minimum Pension Liability	297,870,851	-	-	-	-
Bond Reacquisition Loss	10,835,297	335,952	4,807,625	-	-
Section 475 Adj	(14,740,571)	56,579,953	134,070,458	-	-
Capitalized Costs	6,437,568	8,474,081	9,278,777	-	-
Reg Asset-HCM	2,759,899	132,828	1,743,428	-	-
Reg Asset-MOARK	2,889,273	78,328	1,155,764	-	-
TCBY Tower (CADC)	297,592	-	-	-	-
Misc Cap Costs	4,033,009	487,351	1,932,396	-	-
Reg Asset-30yr Retail	3,098,721	85,621	1,257,355	-	-
Prepaid Expenses	2,358,175	3,263,021	4,297,984	-	-
Income Tax Adj	33,511,040	-	-	-	-
	<u>\$462,420,783</u>	<u>\$154,033,069</u>	<u>\$279,264,886</u>	<u>\$ -</u>	<u>\$ -</u>

	DEBITS		CREDITS		BALANCE AT END OF YEAR
	ACCOUNT CREDITED	AMOUNT	ACCOUNT DEBITED	AMOUNT	
Reg Asset-Securitization		\$ -		\$ -	\$ 14,475,160
Reg Asset-MISO		-		-	1,450,307
Replace Energy Fuel		-		-	17,535,443
System Equalization Agrmt		-		-	28,721,629
Maint/Refueling Reserve		-		-	14,762,225
Minimum Pension Liability	182.3	105,622,678		-	192,248,173
Bond Reacquisition Loss		-		-	6,363,624
Section 475 Adj		-		-	(92,231,076)
Capitalized Costs		-		-	5,632,872
Reg Asset-HCM		-		-	1,149,299
Reg Asset-MOARK		-		-	1,811,837
TCBY Tower (CADC)	123.1	297,592		-	-
Misc Cap Costs		-		-	2,587,964
Reg Asset-30yr Retail		-		-	1,926,987
Prepaid Expenses		-		-	1,323,212
Income Tax Adj	182.3	257,511,147	190	224,000,107	-
		<u>\$363,431,417</u>		<u>\$224,000,107</u>	<u>\$197,757,656</u>

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Certain Investments in Debt & Equity Securities:					
2	ANO 1 Qualified Fund - Valuation Acct	155,625,873	128	9,804,978	48,021,754	193,842,649
3	ANO 2 Qualified Fund - Valuation Acct	125,125,660	128	1,202,126	36,283,135	160,206,669
4						
5	Income Taxes	22,786,382			963,036,775	985,823,157
6						
7	Energy Efficiency Rider - Over-Recovery					
8	07-085-TF	7,458,860	908	6,169,273		1,289,587
9						
10	MISO Rider Over-Recovery	17,696,829	407.4	9,851,690		7,845,139
11						
12	Formula Rate Plan - Over-Recovery					
13	Mabelvale and Lynch Units				407,363	407,363
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	328,693,604		27,028,067	1,047,749,027	1,349,414,564

ELECTRIC OPERATING REVENUES (Account 400)

- 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	761,280,444	782,206,823
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	491,248,189	491,226,740
5	Large (or Ind.) (See Instr. 4)	468,307,788	441,955,479
6	(444) Public Street and Highway Lighting	8,853,802	8,716,905
7	(445) Other Sales to Public Authorities	9,855,121	9,627,484
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,739,545,344	1,733,733,431
11	(447) Sales for Resale	249,028,378	167,148,618
12	TOTAL Sales of Electricity	1,988,573,722	1,900,882,049
13	(Less) (449.1) Provision for Rate Refunds	430,419	504,614
14	TOTAL Revenues Net of Prov. for Refunds	1,988,143,303	1,900,377,435
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,585,816	10,075,188
17	(451) Miscellaneous Service Revenues	2,774,056	2,867,821
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	7,472,466	6,388,966
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	8,243,697	30,117,145
22	(456.1) Revenues from Transmission of Electricity of Others	98,813,623	112,528,552
23	(457.1) Regional Control Service Revenues	10,259,801	9,322,827
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	137,149,459	171,300,499
27	TOTAL Electric Operating Revenues	2,125,292,762	2,071,677,934

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.

8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.

9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,298,416	7,618,443	591,113	589,524	2
				3
5,824,752	5,988,103	93,566	92,791	4
7,528,301	6,795,449	23,426	23,858	5
78,392	78,026	623	612	6
158,595	159,365	135	94	7
				8
				9
20,888,456	20,639,386	708,863	706,879	10
8,331,076	8,724,404	1	1	11
29,219,532	29,363,790	708,864	706,880	12
				13
29,219,532	29,363,790	708,864	706,880	14

Line 12, column (b) includes \$ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2017/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

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.

Schedule Page: 300 Line No.: 21 Column: b

Other Electric Revenues include:

Unbilled Revenue	\$4,926,475 *
MISO Mkt Sch 11 Wholesale Distribution Revenue	2,164,423
AR Gross Receipts Tax	706,882
Affiliate Service Fee Revenue	245,000
Little Rock Air Force Base	216,459
Third Party Sales of Inventory	(15,711)
Other	169

Total	\$8,243,697
	=====

*Includes 43,181 MWH

Schedule Page: 300 Line No.: 21 Column: c

Other Electric Revenues include:

Unbilled Revenue	\$26,610,218 *
MISO Mkt Sch 11 Wholesale Distribution Revenue	2,181,593
AR Gross Receipts Tax	784,210
Little Rock Air Force Base	252,164
Affiliate Service Fee Revenue	245,000
Third Party Sales of Inventory	43,876
Other	84

Total	\$30,117,145
	=====

*Includes 201,242 MWH

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	MISO Sch 1 System Control & Dispatch	259,271	766,946	1,390,775	1,924,407
2	MISO Sch 2 Reactive	1,296,294	3,153,830	5,605,441	7,702,186
3	AECC MISO Sch 1	241,260	241,515	241,515	241,515
4	AECC MISO Sch 2	391,280	391,693	391,693	391,693
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	2,188,105	4,553,984	7,629,424	10,259,801

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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	RESIDENTIAL					
2	RS Gen. Purpose Res.	7,206,677	561,781,311	587,958	12,257	0.0780
3	RS3 Gen. Purpose Res.	6,753	535,815	420	16,079	0.0793
4	RT Opt. Res. Time-of-Use	538	43,169	48	11,208	0.0802
5	RMT Res Energy Mgmt TOU	395	30,045	26	15,192	0.0761
6	L4 All Night Outdoor Lighting	83,598	9,006,737	2,616	31,956	0.1077
7	SGS Small General Service	455	40,118	45	10,111	0.0882
8	NDCR ANO Decommissioning Cost		1,024,462			
9	GGR Grand Gulf Rider		56,290,357			
10	ECR Energy Cost Recovery Rider		105,519,577			
11	PCA Production Costs Allocation R		618,873			
12	EECR Energy Efficiency Cost Rate		23,684,220			
13	MFA Municipal Franchise Adj		20,887,155			
14	GMES Gov't Mandated Exp Srchg		-3			
15	FLCF Federal Litig Consult Fee		362,088			
16	CCR Capacity Cost Recovery Rider		-215,782			
17	MISO		-43,040,143			
18	IBRA Interim Base Rate Adjustment		3,910			
19	FRP Formula Rate Plan		24,708,535			
20	TOTAL RESIDENTIAL	7,298,416	761,280,444	591,113	12,347	0.1043
21						
22						
23	COMMERCIAL					
24	SG1 Small Gen. Service	3,042,576	218,554,489	86,217	35,290	0.0718
25	SG2 Small Gen. Service	17,773	1,167,105	25	710,920	0.0657
26	SG3 Small Gen. Service	657	39,926	6	109,500	0.0608
27	SG4 Small Gen. Service	9,206	553,041	30	306,867	0.0601
28	SG6 Small Gen Service	57	5,290	2	28,500	0.0928
29	SG7 Small Gen. Service	10,612	767,961	716	14,821	0.0724
30	GT1 Opt. LGS Time-of-Use	672,569	30,429,026	360	1,868,247	0.0452
31	GT2 Opt. LGS Time-of-Use	44,018	1,879,386	7	6,288,286	0.0427
32	GT4 Opt. LGS Time-of-Use	33,132	1,330,328	9	3,681,333	0.0402
33	IG1 LGS TOU Interruptible	6,768	163,637	2	3,384,000	0.0242
34	IG4 LGS TOU Interruptible	237,728	4,333,656	4	59,432,000	0.0182
35	LG1 Large Gen. Service	1,021,900	53,808,369	1,004	1,017,829	0.0527
36	LG2 Large Gen. Service	30,168	1,521,638	12	2,514,000	0.0504
37	LG4 Large Gen. Service	16,858	946,119	11	1,532,545	0.0561
38	IL1 LGS Interruptible	17,790	436,193	5	3,558,000	0.0245
39	IL2 LGS Interruptible	4,396	235,772	1	4,396,000	0.0536
40	LP1 Large Power Service	29,850	1,461,630	4	7,462,500	0.0490
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	LP2 Large Power Service	4,472	281,036	1	4,472,000	0.0628
2	LP4 Large Power Service	34,810	1,585,958	3	11,603,333	0.0456
3	PT1 Opt. LPS Time-of-Use	84,857	3,401,405	9	9,428,556	0.0401
4	PT2 Opt. LPS Time-of-Use	139,211	5,587,422	8	17,401,375	0.0401
5	PT4 Opt. LPS Time-of-Use	207,631	8,158,214	8	25,953,875	0.0393
6	IT4 LPS Time-of-Use Interruptib	15,232	277,476	1	15,232,000	0.0182
7	CTV Comm. Ant. & TV Amp.	24,460	1,819,597	2,749	8,898	0.0744
8	L4 All Night Outdoor Lighting	114,200	8,952,922	2,292	49,825	0.0784
9	LEDSL Municipal Street Lighting	-2	-104			0.0520
10	APA Agricultural Water Pump Svc	10	1,032	1	10,000	0.1032
11	APB Agricultural Water Pump Svc	6	696			0.1160
12	FA General Farm Service	1,946	112,664	36	54,056	0.0579
13	FAC General Farm Service	1,733	102,276	11	157,545	0.0590
14	MP Municipal Pump Service	16	1,010			0.0631
15	L2 Traffic Signal Service	112	18,472	32	3,500	0.1649
16	NDCR ANO Decommissioning Cost		547,815			
17	GGR Grand Gulf Rider		32,493,090			
18	ECR Energy Cost Recovery Rider		84,886,334			
19	PCA Production Costs Allocation R		477,186			
20	EECR Energy Efficiency Cost Rate		16,379,962			
21	CA Capacity Acquisition Rider		-231			
22	MFA Municipal Franchise Adj		18,650,938			
23	GMES Gov't Mandated Exp Srchg		-38			
24	FLCF Federal Litig Consult Fee		290,633			
25	ANO ANO1 Interim Capacity Cost Re		-87			
26	CCR Capacity Cost Recovery Rider		-130,214			
27	MISO		-24,535,015			
28	IBRA Interim Base Rate Adjustment		16,183			
29	SRC		-1			
30	FRP Formula Rate Plan		14,237,992			
31	TOTAL COMMERCIAL	5,824,752	491,248,189	93,566	62,253	0.0843
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	INDUSTRIAL					
2	FA General Farm Service	74,930	4,928,374	3,932	19,056	0.0658
3	FAC General Farm Service	89,577	6,994,181	1,410	63,530	0.0781
4	SG1 Small Gen. Service	602,386	45,026,316	9,859	61,100	0.0747
5	SG2 Small Gen. Service	56,789	4,088,004	51	1,113,510	0.0720
6	SG3 Small Gen. Service	4,142	238,912	25	165,680	0.0577
7	SG4 Small Gen. Service	57,045	3,455,908	36	1,584,583	0.0606
8	SG5 Small Gen. Service	27,700	3,122,643	6	4,616,667	0.1127
9	SG6 Small Gen. Service	2,056	242,624	1	2,056,000	0.1180
10	IS2 SGS Interruptible	574	29,396	1	574,000	0.0512
11	IS4 SGS Interruptible	25,715	1,352,879	2	12,857,500	0.0526
12	GT1 Opt. LGS Time-of-Use	239,624	10,847,162	108	2,218,741	0.0453
13	GT2 Opt. LGS Time-of-Use	38,976	1,738,118	7	5,568,000	0.0446
14	GT4 Opt. LGS Time-of-Use	213,494	7,665,699	55	3,881,709	0.0359
15	IG1 LGS TOU Interruptible	54,281	1,242,858	4	13,570,250	0.0229
16	IG3 LGS TOU Interruptible	5,863	117,433	1	5,863,000	0.0200
17	IG4 LGS TOU Interruptible	92,880	1,814,693	3	30,960,000	0.0195
18	LG1 Large Gen. Service	449,030	24,505,086	262	1,713,855	0.0546
19	LG2 Large Gen. Service	43,289	2,358,665	15	2,885,933	0.0545
20	LG3 Large Gen. Service	684	38,595	1	684,000	0.0564
21	LG4 Large Gen. Service	85,896	4,555,880	19	4,520,842	0.0530
22	LG5 Large Gen. Service	2,653	292,495	3	884,333	0.1103
23	IL1 LGS Interruptible	23,007	662,188	10	2,300,700	0.0288
24	IL2 LGS Interruptible	23,125	777,087	2	11,562,500	0.0336
25	LP1 Large Power Service	25,645	1,468,959	5	5,129,000	0.0573
26	LP2 Large Power Service	296,142	15,229,523	18	16,452,333	0.0514
27	LP4 Large Power Service	260,393	12,670,683	18	14,466,278	0.0487
28	IP2 LPS Interruptible	30,472	1,101,615	1	30,472,000	0.0362
29	PT1 Opt. LPS Time-of-Use	179,128	7,528,036	17	10,536,941	0.0420
30	PT2 Opt. LPS Time-of-Use	374,316	15,888,680	17	22,018,588	0.0424
31	PT4 Opt. LPS Time-of-Use	1,942,751	68,808,213	49	39,647,980	0.0354
32	PT5 Opt. LPS Time-of-Use	57,480	2,458,998	4	14,370,000	0.0428
33	PT6 Opt. LPS Time-of-Use	38,727	1,484,706	2	19,363,500	0.0383
34	IT1 LPS TOU Interruptible	17,686	444,551	2	8,843,000	0.0251
35	IT2 LPS TOU Interruptible	10,165	127,459	1	10,165,000	0.0125
36	IT4 LPS TOU Interruptible	647,423	20,158,344	4	161,855,750	0.0311
37	IT6 LPS TOU Interruptible	1,181,602	32,087,404	3	393,867,333	0.0272
38	APA Agricultural Water Pump Svc	164,218	14,883,667	5,447	30,148	0.0906
39	APB Agricultural Water Pump Svc	32,487	3,743,039	1,709	19,009	0.1152
40	CGS Cotton Ginning Service	29,539	2,206,722	35	843,971	0.0747
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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 Pages 310-311.
- Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	L4 All Night Outdoor Lighting	11,165	1,182,330	278	40,162	0.1059
2	SS Standby Service	15,246	2,520,328			0.1653
3	C23 Cogeneration		807	3		
4	NDCR ANO Decommissioning Cost		498,878			
5	GGR Grand Gulf Rider		30,405,670			
6	ECR Energy Cost Recovery Rider		109,172,443			
7	PCA Production Costs Allocation R		627,799			
8	EECR Energy Efficiency Cost Rate		12,102,574			
9	CA Capacity Acquisition Rider		-1,088			
10	SDR Storm Damage Rider		-37			
11	MFA Municipal Franchise Adj		2,443,313			
12	GMES Gov't Mandated Exp Srchg		-29			
13	FLCF Federal Litig Consult Fee		373,725			
14	ANOR ANO1 Interim Capacity Cost		-63			
15	CCR Capacity Cost Recovery Rider		-117,609			
16	MISO		-28,789,061			
17	IBRA Interim Base Rate Adjustment		6,157			
18	SRC		-26			
19	FRP Formula Rate Plan		11,493,867			
20	Miscellaneous		2,015			
21	TOTAL INDUSTRIAL	7,528,301	468,307,788	23,426	321,365	0.0622
22						
23	PUBLIC STREET & HWY LIGHT.					
24	L1 Municipal Street Lighting	71,892	6,240,704	309	232,660	0.0868
25	L1SH Municipal Shielded Street Li	197	13,607	1	197,000	0.0691
26	L2 Traffic Signal Service	5,991	483,080	259	23,131	0.0806
27	L4 All Night Outdoor Lighting	294	25,558	54	5,444	0.0869
28	LED SL Municipal Street Lighting	18	1,045			0.0581
29	NDCR ANO Decommissioning Cost		12,344			
30	GGR Grand Gulf Rider		684,691			
31	ECR Energy Cost Recovery Rider		1,134,171			
32	PCA Production Costs Allocation R		-7,012			
33	EECR Energy Efficiency Cost Rate		161,342			
34	MFA Municipal Franchise Adj		11,354			
35	FLCF Federal Litig Consult Fee		3,919			
36	CCR Capacity Cost Recovery Rider		-866			
37	MISO		-131,576			
38	IBRA		490			
39	FRP Formula Rate Plan		220,951			
40	TOTAL PUBLIC STREET & HWY	78,392	8,853,802	623	125,830	0.1129
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	OTHER SALES TO					
3	PUBLIC AUTHORITIES					
4	SG1 Small Gen. Service	6,018	442,007	100	60,180	0.0734
5	LG1 Large General Service	2,493	137,771	1	2,493,000	0.0553
6	LP4 Large Power Service	15,156	750,360	1	15,156,000	0.0495
7	LP5 Large Power Service	15,333	604,348	1	15,333,000	0.0394
8	PT2 Opt. LPS Time-of-Use	86,873	3,497,218	1	86,873,000	0.0403
9	PT4 Opt. LPS Time-of-Use	32,122	1,288,263	1	32,122,000	0.0401
10	L4 All Night Outdoor Lighting	86	7,341	12	7,167	0.0854
11	MP Municipal Pump Service	514	34,715	18	28,556	0.0675
12	APB Agricultural Water Pump Svc		-196			
13	NDCR ANO Decommissioning Cost		9,402			
14	GGR Grand Gulf Rider		580,961			
15	ECR Energy Cost Recovery Rider		2,290,509			
16	PCA Production Costs Allocation R		13,436			
17	EECR Energy Efficiency Cost Rate		444,026			
18	CA Capacity Acquisition Rider		-1			
19	MFA Municipal Franchise Adj		25,118			
20	FLCF Federal Litig Consult Fee		7,845			
21	CCR Capacity Cost Recovery Rider		-1,938			
22	MISO		-516,463			
23	IBRA		396			
24	FRP Formula Rate Plan		240,003			
25	TOTAL OTHER SALES TO PUB	158,595	9,855,121	135	1,174,778	0.0621
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts.

Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
660,137	32,212,733	8,270,348		40,483,081	1
463,649	41,344,663	5,048,868		46,393,531	2
657,993	32,225,802	8,206,592		40,432,394	3
		115,076		115,076	4
		57,472		57,472	5
		223,762		223,762	6
		6,873		6,873	7
		28,736		28,736	8
		1,006,328	718,985	1,725,313	9
		57,098		57,098	10
		343,635		343,635	11
153	2,905	8,556		11,461	12
6,549,144	171,272	120,221,346	-1,242,672	119,149,946	13
					14
153	2,905	8,556	0	11,461	
8,330,923	105,954,470	143,586,134	-523,687	249,016,917	
8,331,076	105,957,375	143,594,690	-523,687	249,028,378	

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 1 Column: a

(1) Energy and capacity sales associated with the Resource Plan.

Schedule Page: 310 Line No.: 4 Column: a

(2) Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.

Schedule Page: 310 Line No.: 9 Column: j

Related to wholesale distribution.

Schedule Page: 310 Line No.: 12 Column: a

Sales provided under a letter agreement effective March 1992.

Schedule Page: 310 Line No.: 13 Column: j

	CHARGES
MISO Ancillary	\$47,129
MISO Uplift	(1,365,606)
MISO Residual Load	75,805
Total Other Purchases from MISO	<u>(\$1,242,672)</u>

Schedule Page: 310 Line No.: 14 Column: a

Amounts shown in column (h) are Production Demand related revenues.

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)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	5,725,022	5,724,183
5	(501) Fuel	332,699,388	304,289,629
6	(502) Steam Expenses	3,265,116	3,163,143
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,272,867	1,283,859
10	(506) Miscellaneous Steam Power Expenses	4,596,336	3,871,756
11	(507) Rents	297,312	159,641
12	(509) Allowances	439	1,856
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	347,856,480	318,494,067
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	839,635	735,299
16	(511) Maintenance of Structures	896,106	893,625
17	(512) Maintenance of Boiler Plant	10,769,287	9,523,525
18	(513) Maintenance of Electric Plant	4,851,403	4,557,825
19	(514) Maintenance of Miscellaneous Steam Plant	2,182,022	2,021,946
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	19,538,453	17,732,220
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	367,394,933	336,226,287
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	40,781,083	28,851,363
25	(518) Fuel	110,792,252	94,495,683
26	(519) Coolants and Water	5,982,526	6,100,695
27	(520) Steam Expenses	37,746,351	35,115,436
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	44,421,754	56,560,414
32	(525) Rents	1,992,662	2,464,416
33	TOTAL Operation (Enter Total of lines 24 thru 32)	241,716,628	223,588,007
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	30,463,911	23,137,189
36	(529) Maintenance of Structures	261,818	219,711
37	(530) Maintenance of Reactor Plant Equipment	2,180,046	6,852
38	(531) Maintenance of Electric Plant	12,822,353	13,111,070
39	(532) Maintenance of Miscellaneous Nuclear Plant	124,986,480	101,987,282
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	170,714,608	138,462,104
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	412,431,236	362,050,111
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	82,433	182,725
45	(536) Water for Power	261,958	198,925
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	11,887	116,818
48	(539) Miscellaneous Hydraulic Power Generation Expenses	258,283	300,350
49	(540) Rents	10,188	19,626
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	624,749	818,444
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	20,462	45,404
54	(542) Maintenance of Structures	51,421	143,590
55	(543) Maintenance of Reservoirs, Dams, and Waterways	602,853	741,468
56	(544) Maintenance of Electric Plant	412,426	336,682
57	(545) Maintenance of Miscellaneous Hydraulic Plant	333,504	255,398
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,420,666	1,522,542
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	2,045,415	2,340,986

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,094,260	2,703,670
63	(547) Fuel	24,478	282,366
64	(548) Generation Expenses	2,211,181	2,178,922
65	(549) Miscellaneous Other Power Generation Expenses	4,645,568	4,847,490
66	(550) Rents	34,373	82,532
67	TOTAL Operation (Enter Total of lines 62 thru 66)	10,009,860	10,094,980
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,039,312	1,065,711
70	(552) Maintenance of Structures	416,767	576,151
71	(553) Maintenance of Generating and Electric Plant	24,199,058	32,987,133
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	660,068	387,276
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	26,315,205	35,016,271
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	36,325,065	45,111,251
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	230,643,995	233,343,312
77	(556) System Control and Load Dispatching	1,023,582	1,087,217
78	(557) Other Expenses	-40,585,329	-73,817,092
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	191,082,248	160,613,437
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,009,278,897	906,342,072
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,964,333	5,050,641
84			
85	(561.1) Load Dispatch-Reliability	14,476	29,252
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,358,237	3,797,377
87	(561.3) Load Dispatch-Transmission Service and Scheduling	104,704	107,826
88	(561.4) Scheduling, System Control and Dispatch Services	5,303,549	4,816,144
89	(561.5) Reliability, Planning and Standards Development	671,582	788,092
90	(561.6) Transmission Service Studies	-124	2,175
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	666,820	598,187
93	(562) Station Expenses	653,765	948,467
94	(563) Overhead Lines Expenses	582,044	419,984
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	7,576,008	6,553,906
97	(566) Miscellaneous Transmission Expenses	5,640,378	6,311,472
98	(567) Rents	178,279	167,727
99	TOTAL Operation (Enter Total of lines 83 thru 98)	29,714,051	29,591,250
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	5,325,166	5,307,313
102	(569) Maintenance of Structures	302,980	295,121
103	(569.1) Maintenance of Computer Hardware	-617	219
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,788,960	1,704,642
108	(571) Maintenance of Overhead Lines	4,771,037	3,338,160
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	116,670	111,276
111	TOTAL Maintenance (Total of lines 101 thru 110)	12,304,196	10,756,731
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	42,018,247	40,347,981

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
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	4,231,149	4,048,868
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	4,231,149	4,048,868
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 Op Exps (Total 123 and 130)	4,231,149	4,048,868
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	13,279,223	12,567,417
135	(581) Load Dispatching	711,224	662,552
136	(582) Station Expenses	526,405	503,011
137	(583) Overhead Line Expenses	843,775	1,336,880
138	(584) Underground Line Expenses	1,745,241	1,770,710
139	(585) Street Lighting and Signal System Expenses	382,980	203,797
140	(586) Meter Expenses	4,414,472	4,232,842
141	(587) Customer Installations Expenses	1,074,914	1,094,109
142	(588) Miscellaneous Expenses	3,371,471	2,831,481
143	(589) Rents	1,955,772	1,996,535
144	TOTAL Operation (Enter Total of lines 134 thru 143)	28,305,477	27,199,334
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,650,478	3,178,526
147	(591) Maintenance of Structures	1,098,540	1,187,710
148	(592) Maintenance of Station Equipment	2,809,664	2,288,618
149	(593) Maintenance of Overhead Lines	43,782,714	37,512,477
150	(594) Maintenance of Underground Lines	1,821,760	2,259,946
151	(595) Maintenance of Line Transformers	19,460	16,483
152	(596) Maintenance of Street Lighting and Signal Systems	1,976,514	2,047,274
153	(597) Maintenance of Meters	82,648	61,672
154	(598) Maintenance of Miscellaneous Distribution Plant	1,634,328	1,770,341
155	TOTAL Maintenance (Total of lines 146 thru 154)	56,876,106	50,323,047
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	85,181,583	77,522,381
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	408,207	409,435
160	(902) Meter Reading Expenses	8,820,909	7,987,638
161	(903) Customer Records and Collection Expenses	21,053,910	19,690,224
162	(904) Uncollectible Accounts	5,887,064	6,083,649
163	(905) Miscellaneous Customer Accounts Expenses	45,105	48,919
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	36,215,195	34,219,865

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	543,463	528,353
168	(908) Customer Assistance Expenses	50,673,594	63,972,162
169	(909) Informational and Instructional Expenses	944,580	911,692
170	(910) Miscellaneous Customer Service and Informational Expenses	1,229,962	1,262,955
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	53,391,599	66,675,162
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,666	67,030
175	(912) Demonstrating and Selling Expenses		426
176	(913) Advertising Expenses	223,512	350,498
177	(916) Miscellaneous Sales Expenses	132,028	193,215
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	357,206	611,169
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	43,119,682	39,102,754
182	(921) Office Supplies and Expenses	4,339,322	4,168,969
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	24,195,724	31,094,443
185	(924) Property Insurance	34,471,251	34,915,011
186	(925) Injuries and Damages	6,092,042	4,056,067
187	(926) Employee Pensions and Benefits	66,661,311	66,829,208
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,498,773	2,045,703
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	475,940	454,622
192	(930.2) Miscellaneous General Expenses	-253,737	-3,805,107
193	(931) Rents	2,995,309	3,092,034
194	TOTAL Operation (Enter Total of lines 181 thru 193)	184,595,617	181,953,704
195	Maintenance		
196	(935) Maintenance of General Plant	3,518,037	3,513,259
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	188,113,654	185,466,963
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,418,787,530	1,315,234,461

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Entergy System Power Pool	OS		N/A	N/A	N/A
2	System Energy Resources, Inc.	OS		N/A	N/A	N/A
3	Southwest Power Pool	OS		N/A	N/A	N/A
4	Midcontinent ISO, Inc.	OS	OATT	N/A	N/A	N/A
5	North Little Rock Electric Dept	OS		N/A	N/A	N/A
6	Little Rock Wastewater	OS	M23	N/A	N/A	N/A
7	West Memphis	OS	99	N/A	N/A	N/A
8	Capacity Deferrals			N/A	N/A	N/A
9	Small Residential Generation	OS		N/A	N/A	N/A
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					34,684	34,684	1
2,403,054			214,278,424	25,812,000	-23,499,618	216,590,806	2
	160,068	233,092		2			3
1,725,499			-2,898	58,133,816	-44,045,867	14,085,051	4
457				26,864		26,864	5
508				13,764		13,764	6
4,884			293,615	196,216		489,831	7
					-597,143	-597,143	8
4				136		136	9
							10
							11
							12
							13
							14
4,134,406	160,068	233,092	214,569,141	84,182,798	-68,107,944	230,643,995	

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 1 Column: I

RPCE interest recorded in accordance with Order on Compliance in ER10-1350 for 2010 (TY2009).

Schedule Page: 326 Line No.: 2 Column: a

Energy and capacity charges from Grand Gulf Nuclear Power Plant.

Schedule Page: 326 Line No.: 2 Column: I

Represents (\$17,527,575) for deferral on over/under recovery under the Grand Gulf Rider and the turnaround of the Grand Gulf Accelerated Recovery Tariff approved by the FERC that provided for the acceleration of Entergy Arkansas's and Entergy Mississippi's Grand Gulf purchased power obligations with System Energy Resources and (\$5,972,043) related to GGART.

Schedule Page: 326 Line No.: 4 Column: I

	CHARGES
MISO Ancillary	\$1,180,692
MISO Congestion	(45,263,941)
MISO Losses	(3,826,996)
MISO Uplift	3,351,247
MISO Residual Load	120,011
MISO Administration	393,120
Total Other Purchases from MISO	<u>(\$44,045,867)</u>

Schedule Page: 326 Line No.: 8 Column: I

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

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2017/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	MISO	Various	Various	
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
	Various	Various				1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	0	0	

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	98,813,623		98,813,623	1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	98,813,623	0	98,813,623	

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
 (Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Associated Electric				187,250			187,250
2	Cooperative Inc.							
3								
4	Southwestern Power				311,969			311,969
5	Administration							
6								
7	Midcontinent				7,076,789			7,076,789
8	Independent							
9	System Operator Inc							
10								
11								
12								
13								
14								
15								
16								
	TOTAL				7,576,008			7,576,008

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: a

These expenses represent the charges incurred from a third party for the utilization of their 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.

Schedule Page: 332 Line No.: 4 Column: a

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

Schedule Page: 332 Line No.: 7 Column: a

The Utility Operating Companies are transmission owning members of the Midcontinent Independent System Operator (MISO) RTO. MISO is the transmission provider under the MISO Attachment O. Entergy Arkansas incurred charges from MISO for the purchase of network transmission service under the MISO Attachment O. MISO calculated the network service charges applicable to Entergy Arkansas and billed the entity for such service.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	836,206
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	489,665
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	5% surcharge on regulated company billings to	
7	non-regulated affiliates	-1,752,103
8	Purchasing and contracts support	457,388
9	Computer software purchases	3,516,967
10	Irrigation load control amortization	1,125,592
11	Directors meetings and expenses	19,601
12	Section 263A research - tax services	73,632
13	Renewable Requests for Proposals (RFP) for delivery	
14	of electric capacity, energy and other products	-150,000
15	System aircraft	33,534
16	MISO amortization - retail	17,982
17	Unbilled external jobbing orders	-271,910
18	Citibank refunds	-106,408
19	Co-owner credits - Independence	-2,983,094
20	Co-owner credits - White Bluff	-1,607,128
21	Ice storm securitization financing costs	20,728
22	Other	25,611
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	-253,737

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

- 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 8 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 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			17,716,239		17,716,239
2	Steam Production Plant	10,074,604	-63,992			10,010,612
3	Nuclear Production Plant	70,184,401	2,208,085			72,392,486
4	Hydraulic Production Plant-Conventional	911,112	-2,188			908,924
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	33,333,690	-24			33,333,666
7	Transmission Plant	36,287,936				36,287,936
8	Distribution Plant	82,819,005				82,819,005
9	Regional Transmission and Market Operation					
10	General Plant	22,000,228				22,000,228
11	Common Plant-Electric					
12	TOTAL	255,610,976	2,141,881	17,716,239		275,469,096

B. Basis for Amortization Charges

Generally, amortization varies by the useful life of the asset and is most commonly amortized over 5-Year, 10-Year, or 15-Year periods. Amortization charges for electric plant (Accounts 404 and 405) are calculated on assets individually and as a result each asset has their own basis.

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 1 Column: d

Includes \$18,389 of service company amortization billing allocations.

Schedule Page: 336 Line No.: 10 Column: b

Includes \$7,587,987 of service company depreciation billing allocations.

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.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FEDERAL ENERGY REGULATORY COMMISSION				
2					
3	Various FERC dockets related to				
4	System Agreement Litigation		23,438	23,438	
5					
6	Docket No. 07-130-TF				
7	APSC consultant fees incurred in Federal				
8	Litigation (Fed Litigation Consulting Fees)		1,039,302	1,039,302	1,060,393
9					
10	Other expenses incurred in connection with				
11	MISO and Other Transmission				
12	related FERC Dockets (1)		29,678	29,678	
13					
14	Other expenses incurred in connection with				
15	various filings before FERC		111,548	111,548	
16					
17	ARKANSAS PUBLIC SERVICE COMMISSION				
18					
19	Docket No. 16-036-R				
20	EAI Formula Rate Plan		357,717	357,717	
21					
22	Docket No. 16-027-R & Docket No. 16-028-U				
23	Net Metering & Distributed Generation		58,661	58,661	
24	Rulemaking				
25					
26	Docket No. 07-055-TF				
27	EAI Energy Efficiency		61,640	61,640	
28					
29	Docket No. 15-015-U				
30	2015 EAI Rate Case		34,187	34,187	141,039
31					
32	Docket Nos. 15-014-U and 17-041-U				
33	Stuttgart and Chicot Solar Projects		20,234	20,234	
34					
35	Other expenses incurred in connection with				
36	various filings before the APSC		570,149	570,149	
37					
38	Expenses incurred in connection with various				
39	filings before the APSC and FERC		192,219	192,219	
40					
41	Note (1) Transmission Related				
42					
43					
44					
45					
46	TOTAL		2,498,773	2,498,773	1,201,432

REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
Electric	928	23,438					4
							5
							6
							7
Electric	928	1,039,302	127,470			1,187,863	8
							9
							10
							11
Electric	928	29,678					12
							13
							14
Electric	928	111,548					15
							16
							17
							18
							19
Electric	928	357,717					20
							21
							22
Electric	928	58,661					23
							24
							25
							26
Electric	928	61,640					27
							28
							29
Electric	928	34,187		928	33,849	107,190	30
							31
							32
Electric	928	20,234					33
							34
							35
Electric	928	570,149					36
							37
							38
Electric	928	192,219					39
							40
							41
							42
							43
							44
							45
		2,498,773	127,470		33,849	1,295,053	46

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 & 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 & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	A(2)	
2	A(3)	
3	B(1)	EPRI Dues
4	B(1)	EPRI Dues
5	B(1)	EPRI Dues
6	B(1)	EPRI Research
7	B(2)	Edison Electric Institute Dues
8	B(3)	NERC Dues
9	B(4)	Gartner, Inc. Dues
10	B(4)	Other
11		
12	Total	
13		
14	(1) 107, 408.1, 567, 568, 926	
15	(2) 107, 408.1, 506, 588, 592, 926	
16	(3) 580, 930.2	
17	(4) 107, 560, 568, 580, 588, 921, 923, 930.2	
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
- (3) Research Support to Nuclear Power Groups
- (4) Research Support to Others (Classify)
- (5) Total Cost Incurred

3. Include in column (c) all R, D & 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 & 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 & 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 & 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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
173,954		(1)	173,954		1
7,202		(2)	7,202		2
	400,470	506	400,470		3
	178,284	930.2	178,284		4
	1,270,481	517	1,270,481		5
	237,456	568,923	237,456		6
	369,614	(3)	369,614		7
	666,820	561.8	666,820		8
	104,649	930.2	104,649		9
	340,522	(4)	340,522		10
					11
181,156	3,568,296		3,749,452		12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	52,473,488		52,473,488
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	39,581,907		39,581,907
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	39,581,907		39,581,907
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,118,475		4,118,475
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,118,475		4,118,475
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock Exp Undistributed (Account 152)	4,800,030		4,800,030
79	Stores Expense Undistributed (Account 163)	2,716,265		2,716,265
80	Miscellaneous Current and Accrued Assets (Account 174)	1,088,290		1,088,290
81	Clearing Accounts (Account 184)	3,519,047		3,519,047
82	Miscellaneous Deferred Debits (Account 186)	219,370		219,370
83	Accumulated Provisions for Property Insurance (Account 2281)	4,367,596		4,367,596
84	Accumulated Miscellaneous Operating Provisions (Account 2284)	4,565		4,565
85	PAYROLL TAX (Account 408199)	425		425
86	Expenses-Nonutility Oper (Account 4171)	13,391		13,391
87	Civil, Political, and Related Expenses (Account 4264)	189,435		189,435
88	Other Deductions (Account 4265)	1,676,504		1,676,504
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	18,594,918		18,594,918
96	TOTAL SALARIES AND WAGES	114,768,788		114,768,788

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 96 Column: d

The following payroll charges from Entergy Services are not included in this schedule and are included in the Electric O&M schedule (pages 320-323) only:

Production:	\$10,427,461
Transmission:	\$6,857,040
Distribution:	\$2,216,228
Customer Accts:	\$4,111,543
Customer Service:	\$559,764
Sales:	\$98,072
Administrative & General:	\$27,312,397

In addition, Entergy Operations production payroll charges of \$112,689,007 and administrative and general charges of \$5,529,225 are not included in this schedule and are included in the Electric O&M schedule (pages 320-323) only.

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2017/Q4</u>
--	---	---------------------------------------	--

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 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 order of the Commission or other authorization.

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2017/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	7,734,941	41,313,724	51,332,008	58,133,816
3	Net Sales (Account 447)	(43,758,742)	(50,003,053)	(94,441,279)	(120,221,346)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(36,023,801)	(8,689,329)	(43,109,271)	(62,087,530)

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: b

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, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

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)
1	January	6,057	6	1100	3,312	2,602		143		
2	February	4,758	9	900	2,434	2,181		143		
3	March	4,711	15	800	2,653	1,915		143		
4	Total for Quarter 1				8,399	6,698		429		
5	April	4,735	19	1700	2,768	1,824		143		
6	May	5,369	16	1700	3,044	2,182		143		
7	June	6,110	14	1800	3,307	2,660		143		
8	Total for Quarter 2				9,119	6,666		429		
9	July	7,053	20	1700	3,916	2,994		143		
10	August	6,276	22	1600	3,481	2,652		143		
11	September	5,980	21	1600	3,357	2,480		143		
12	Total for Quarter 3				10,754	8,126		429		
13	October	5,390	9	1500	2,894	2,353		143		
14	November	4,404	20	900	2,357	1,904		143		
15	December	5,501	28	900	2,785	2,573		143		
16	Total for Quarter 4				8,036	6,830		429		
17	Total Year to Date/Year				36,308	28,320		1,716		

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
- (2) Report on Column (b) by month the transmission system's peak load.
- (3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
- (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports 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)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2017/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	20,888,456
3	Steam	13,684,296	23	Requirements Sales for Resale (See instruction 4, page 311.)	153
4	Nuclear	12,692,915	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	8,330,923
5	Hydro-Conventional	96,299	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	52,895
7	Other		27	Total Energy Losses	1,262,465
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	30,534,892
9	Net Generation (Enter Total of lines 3 through 8)	26,473,510			
10	Purchases	4,134,406			
11	Power Exchanges:				
12	Received	160,068			
13	Delivered	233,092			
14	Net Exchanges (Line 12 minus line 13)	-73,024			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	30,534,892			

Name of Respondent Energy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2017/Q4</u>
---	---	---------------------------------------	--

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).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	2,691,442	840,873	3,656	6	1100
30	February	2,367,695	850,699	2,975	9	900
31	March	2,394,276	716,196	2,981	14	800
32	April	1,811,848	230,507	3,046	19	1700
33	May	1,974,303	212,436	3,391	30	1600
34	June	2,318,713	330,177	4,021	14	1700
35	July	3,180,938	796,754	4,616	20	1600
36	August	3,241,388	1,095,020	4,120	22	1600
37	September	2,568,828	617,776	4,014	21	1600
38	October	2,533,787	753,695	3,515	9	1600
39	November	2,489,887	843,301	2,927	20	900
40	December	2,961,787	1,043,489	3,489	27	2100
41	TOTAL	30,534,892	8,330,923			

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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 Mct. 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.

Line No.	Item (a)	Plant Name: <i>Lake Catherine</i> (b)	Plant Name: <i>Union Power Station</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Combined Cycle
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Outdoor
3	Year Originally Constructed	1950	2003
4	Year Last Unit was Installed	1970	2003
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	553.00	577.00
6	Net Peak Demand on Plant - MW (60 minutes)	529	556
7	Plant Hours Connected to Load	925	3898
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	523	533
10	When Limited by Condenser Water	522	509
11	Average Number of Employees	44	14
12	Net Generation, Exclusive of Plant Use - KWh	101811928	1618334236
13	Cost of Plant: Land and Land Rights	33725	2817491
14	Structures and Improvements	6988075	137193397
15	Equipment Costs	58571071	172098806
16	Asset Retirement Costs	322593	0
17	Total Cost	65915464	312109694
18	Cost per KW of Installed Capacity (line 17/5) Including	119.1961	540.9180
19	Production Expenses: Oper, Supv, & Engr	2049101	598863
20	Fuel	13712139	36765185
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	550839	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	407984	784560
26	Misc Steam (or Nuclear) Power Expenses	1211061	1332434
27	Rents	110279	2822
28	Allowances	9	4
29	Maintenance Supervision and Engineering	277889	235953
30	Maintenance of Structures	118389	32368
31	Maintenance of Boiler (or reactor) Plant	2027539	0
32	Maintenance of Electric Plant	2040965	12646125
33	Maintenance of Misc Steam (or Nuclear) Plant	338189	143331
34	Total Production Expenses	22844383	52541645
35	Expenses per Net KWh	0.2244	0.0325
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	MCF
38	Quantity (Units) of Fuel Burned	0 1296197 0 0	11623868 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 1030681 0 0	1024814 0
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
41	Average Cost of Fuel per Unit Burned	0.000 10.579 0.000 0.000	3.163 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 10.264 0.000 0.000	3.086 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.135 0.000 0.000	0.023 0.000
44	Average BTU per KWh Net Generation	0.000 13121.900 0.000 0.000	7360.840 0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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 Mct. 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.

Line No.	Item (a)	Plant Name: White Bluff (b)			Plant Name: Independence (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor			Full Outdoor		
3	Year Originally Constructed	1980			1983		
4	Year Last Unit was Installed	1981			1983		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1026.00			283.50		
6	Net Peak Demand on Plant - MW (60 minutes)	1657			845		
7	Plant Hours Connected to Load	8266			5284		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1639			839		
10	When Limited by Condenser Water	1639			839		
11	Average Number of Employees	115			57		
12	Net Generation, Exclusive of Plant Use - KWh	4583922557			1011619772		
13	Cost of Plant: Land and Land Rights	1109655			773576		
14	Structures and Improvements	47412994			12242174		
15	Equipment Costs	477148718			156965139		
16	Asset Retirement Costs	2924163			655933		
17	Total Cost	528595530			170636822		
18	Cost per KW of Installed Capacity (line 17/5) Including	515.2003			601.8936		
19	Production Expenses: Oper, Supv, & Engr	3088072			587548		
20	Fuel	105217931			24114852		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2506275			208002		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	730087			134795		
26	Misc Steam (or Nuclear) Power Expenses	3569296			-326739		
27	Rents	152018			35014		
28	Allowances	349			63		
29	Maintenance Supervision and Engineering	501662			60083		
30	Maintenance of Structures	601379			176337		
31	Maintenance of Boiler (or reactor) Plant	6965284			1776464		
32	Maintenance of Electric Plant	2073268			737170		
33	Maintenance of Misc Steam (or Nuclear) Plant	668295			1175538		
34	Total Production Expenses	126073916			28679127		
35	Expenses per Net KWh	0.0275			0.0283		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Oil	Coal		Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	TON		BBL	TON		BBL
38	Quantity (Units) of Fuel Burned	2725549	0	6354	604583	0	2689
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	17219679	0	5900783	17258522	0	5900026
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
41	Average Cost of Fuel per Unit Burned	38.440	0.000	70.346	39.545	0.000	76.836
42	Average Cost of Fuel Burned per Million BTU	2.232	0.000	11.922	2.291	0.000	13.023
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10246.806	0.000	0.000	10330.039	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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 Mct. 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.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. 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. 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.

Plant Name: Ouachita 1 & 2 (d)		Plant Name: Hot Spring (e)		Plant Name: Arkansas Nuclear One (f)		Line No.			
	Gas Turbine		Gas Turbine		Nuclear		1		
	Outdoor		Outdoor		N/A		2		
	2002		2002		1974		3		
	2002		2002		1980		4		
	603.00		715.00		1978.00		5		
	573		614		1878		6		
	7511		7565		14496		7		
	0		0		0		8		
	545		609		1824		9		
	509		609		1824		10		
	19		26		1048		11		
	2918656096		3449951193		12692915000		12		
	332811		1925138		2641307		13		
	152853796		119711229		563038681		14		
	145686892		226803471		2449698012		15		
	0		0		110910357		16		
	298873499		348439838		3126288357		17		
	495.6443		487.3284		1580.5300		18		
	1255209		1240489		40781083		19		
	68290661		84411522		110792252		20		
	0		0		5982526		21		
	0		0		37746351		22		
	0		0		0		23		
	0		0		0		24		
	545644		880978		0		25		
	1999683		1456169		44421754		26		
	7942		23610		1992662		27		
	9		5		0		28		
	189859		613501		30463911		29		
	235498		148902		261818		30		
	0		0		2180046		31		
	7474905		4078028		12822353		32		
	418696		98041		124986480		33		
	80418106		92951245		412431236		34		
	0.0276		0.0269		0.0325		35		
	Gas		Gas		Nuclear		36		
	MCF		MCF		MWH		37		
0	20085092	0	0	25028896	0	0	38577305	0	38
0	1041755	0	0	1029736	0	0	3413105	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	3.400	0.000	0.000	3.373	0.000	0.000	2.872	0.000	41
0.000	3.264	0.000	0.000	3.275	0.000	0.000	0.841	0.000	42
0.000	0.023	0.000	0.000	0.025	0.000	0.000	0.009	0.000	43
0.000	7168.970	0.000	0.000	7470.590	0.000	0.000	10373.380	0.000	44

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. 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. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. 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. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b

Lake Catherine

Lake Catherine Units 1, 2, and 3 were in retired status for the entire year. Unit 4 is still active.

Schedule Page: 402 Line No.: -1 Column: c

Union Power Station

Reflects Entergy Arkansas's 100% ownership in Unit 2 and its 25% ownership in Common facilities.

Schedule Page: 403 Line No.: -1 Column: d

Ouachita 1 & 2

Reflects Entergy Arkansas's 100% interest in Ouachita Units 1 and 2 and its 66.7% interest in Common Plant.

Schedule Page: 402.1 Line No.: -1 Column: b

White Bluff

Reflects Entergy Arkansas's 57% intersert in White Bluff Units 1, 2 and Common Plant.

Schedule Page: 402.1 Line No.: -1 Column: c

Independence

Reflects Entergy Arkansas's 31.5% interest in Independence Unit 1 and its 15.75% interest in Common Plant.

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Carpenter (b)	FERC Licensed Project No. 0 Plant Name: Rimmel (c)
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)	62	12
7	Plant Hours Connect to Load	2,522	2,607
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	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	70,860,811	25,438,010
13	Cost of Plant		
14	Land and Land Rights	1,060,395	244,021
15	Structures and Improvements	1,872,730	1,115,785
16	Reservoirs, Dams, and Waterways	5,973,853	9,871,624
17	Equipment Costs	15,504,158	12,629,638
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	6,187	1,154
20	TOTAL cost (Total of 14 thru 19)	24,417,323	23,862,222
21	Cost per KW of Installed Capacity (line 20 / 5)	436.0236	2,651.3580
22	Production Expenses		
23	Operation Supervision and Engineering	52,444	29,989
24	Water for Power	129,669	132,289
25	Hydraulic Expenses	0	0
26	Electric Expenses	4,565	7,322
27	Misc Hydraulic Power Generation Expenses	122,922	135,361
28	Rents	5,006	5,182
29	Maintenance Supervision and Engineering	8,983	11,479
30	Maintenance of Structures	47,320	4,101
31	Maintenance of Reservoirs, Dams, and Waterways	370,169	232,684
32	Maintenance of Electric Plant	324,644	87,782
33	Maintenance of Misc Hydraulic Plant	176,065	157,439
34	Total Production Expenses (total 23 thru 33)	1,241,787	803,628
35	Expenses per net KWh	0.0175	0.0316

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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 the 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."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
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	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Cecil Lynch (Internal Combustion)	1946	6.00			1,485
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
248				Oil		1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	White Bluff	Keo 6010	500.00		Lat Stl A	17.25		1
2	El Dorado	LA St Ln (Secc) 6004	500.00		Lat Stl A	24.31		1
3	Dell	Miss River 6019	500.00		Lat Stl A	28.39		1
4	Dell	Mo St Lin 6012	500.00		Lat Stl A	9.61		1
5	Hot Springs	McNeil 6014	500.00		Guyed Ste	84.15		1
6	El Dorado	McNeil 6013	500.00		Guyed Ste	37.76		1
7	Independence	Dell 6015	500.00		Lat Stl A	82.85		1
8	Independence	Keo 6016	500.00		Lat Stl A	64.10		1
9	White Bluff	Sheridan 6011	500.00		Lat Stl A	18.63		1
10	ANO	Mayflower 6002	500.00		Lat Stl A	60.88		1
11	Mabelvale-LR Pinnacle	Mayflower 6007	500.00		Lat Stl A	29.93		1
12	ANO	Jct Mablv 6001	500.00		Guyed Alu	48.58		2
13	El Dorado	La St Ln (Gsu) 6003	500.00		Lat Stl A	20.21		1
14	West Memphis	Mabelvale 6009	500.00		Lat Stl A	136.30		1
15	Miss River	West Memphis 6008	500.00		Lat Stl A	1.48		1
16	Jct Mablv	OG&E Connection 6006	500.00		Lat Stl A	85.38		1
17	Mabelvale	El Dorado 6005	500.00		Lat Stl A	95.34		1
18	Sheridan	Hot Springs 6017	500.00		Guyed Ste	26.80		1
19	Holland Bottom	KEO 0806	500.00		Lat Stl A	22.21		1
20	500kv Tie Lines		500.00		Lat Stl A	0.69		
21		Total 500kv Lines						
22								
23	El Dorado	LA State Line 6101	345.00		Guyed Alu	44.00		1
24		Total 345kv Lines						
25								
26	Lake Village Bagby	Miss St Line 6201	230.00		Wood H-Fr	14.07		1
27	Ritch-Wdwrđ	Stuttg Ricuskey Tap 6205	230.00		DC Lat St	17.74		1
28	Ritchie	Miss River 6203	230.00		DC Lat St	0.75		1
29	Ritchie	Brinkley 6202	230.00		Wood H-Fr	44.72		1
30	Ritchie	Woodward 6204	230.00		DC Lat St	80.19	8.91	1
31	Ritchie	Miss River (#2) 6206	230.00		DC Lat St	1.00		1
32	White Bluff	Woodward 626	230.00		Steel	22.92		1
33	Big River Steel	Driver 624	230.00		Steel	2.19		1
34	Big River Steel	Driver 623	230.00		Steel	2.22		1
35		Total 230kv Lines						
36					TOTAL	4,784.34	158.26	214

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1								
2	Thayer South	AR/MO State Line 6368	161.00		Wood H-Fr	0.66		1
3	Rector	AR/MO State Line 6347	161.00		Wood H-Fr	17.57		1
4	Monette Jct	Paragould 6345	161.00		Wood H-Fr	16.64		1
5	Blytheville Elm St	Dell-Monette Jct 6344	161.00		Wood H-Fr	23.39		1
6	Blytheville Elm St	Bly. Gen. Sta. 6343	161.00		Wood H-Fr	0.59		1
7	Blytheville Elm St	Crooked Lake 6373	161.00		Sng Concr	11.04		1
8	Blytheville Elm St	AR/MO State Line 6342	161.00		Wood H-Fr	8.45		1
9	Blytheville Elm St	Osceola 6341	161.00		Wood H-Fr	12.12	5.02	1
10	Cushman	Cave City 6369	161.00		Wood H-Fr	9.61		1
11	Walnut Ridge	Alicia 6348	161.00		Wood H-Fr	3.50		1
12	Walnut Ridge	AR/MO State Line 6367	161.00		Wood H-Fr	48.74		1
13	Pocahontas	Datto 6362	161.00		Wood H-Fr	17.56		1
14	Water Valley	Pocahontas 6365	161.00		Wood H-Fr	5.96		1
15	Hayti	Noranda Gen Station 6352	161.00		Wood H-Fr	27.90		1
16	Hayti	AR/MO State Line 6350	161.00		Wood H-Fr	15.99		1
17	Hayti	Jim Hill Plant 6351	161.00		Wood H-Fr	26.72		1
18	Jim Hill Plant	AR/MO State Line 6353	161.00		Wood H-Fr	1.63		1
19	Crooked Lake	Barfield 6358	161.00		Sng Con P	0.60		1
20	Bull Shoals Sub	Bull Shoals Dam 6370	161.00		Sng Wood	0.57		1
21	Morrilton East	Russellville East 6323	161.00		Wood H-Fr	25.26		1
22	Moses	Parkin/Wynne Indl Tap 6328	161.00		Wood H-Fr	3.83		1
23	Rector	Paragould 6346	161.00		Wood H-Fr	26.67		1
24	LR Pinnacle	Morrilton East 6321	161.00		Wood H-Fr	40.67		1
25	Ebony	Market Tree 6340	161.00		Wood H-Fr	25.92		1
26	Brinkley	Moses 6305	161.00		Wood H-Fr	16.64		1
27	Conway West	Hamlet 6306	161.00		Wood H-Fr	14.31		1
28	Danville	Russellville East 6308	161.00		Wood H-Fr	26.22		1
29	Dell EHV	Jct Blyvl/Osceola 6366	161.00		DC Lat St	5.24	5.02	1
30	Jonesboro	Parkin 6317	161.00		Wood H-Fr	47.32	4.48	1
31	Moses-Newport	(Augusta Taps) 6325	161.00		Wood H-Fr	15.37		1
32	Moses	West Memphis 6329	161.00		Wood H-Fr	43.10		1
33	Moses	Newport 6324	161.00		Wood H-Fr	54.57		1
34	Moses	Parkin 6326	161.00		Wood H-Fr	32.31		1
35	Newport	ARKMO Conn. 6330	161.00		Wood H-Fr	31.73		1
36					TOTAL	4,784.34	158.26	214

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Newport	Jonesboro-HRKMO 6333	161.00		Wood H-Fr	49.70		1
2	Newport	Parkin 6334	161.00		Wood H-Fr	47.84		1
3	Parking	Osceola 6337	161.00		Wood H-Fr	42.95		1
4	Marked Tree	Lepanto 6322	161.00		Wood H-Fr	9.03		1
5	Moses	Parkin (F City N Tap) 6327	161.00		Wood H-Fr	2.69		1
6	Parkin	Kunh Road 6338	161.00		Wood H-Fr	18.88		1
7	Harrison East	SWEPCO Conn. 6314	161.00		Wood H-Fr	41.49		1
8	Hamlet-Hb Spgs S-Gr Fry	(Greenbrair Tap) 6311	161.00		Wood H-Fr	11.97		1
9	Jonesboro	SPA Inter 6320	161.00		Wood H-Fr	0.83		1
10	ISES	Jct Newport/Searcy Pr 6315	161.00		DC Lat St	8.71	7.98	1
11	Osceola	Osceola Industrial 6336	161.00		Wood H-Fr	2.02		1
12	Jonesboro	Parkin (JCW & LHRGT) 6319	161.00		Wood H-Fr	9.78		1
13	ISES/Rutrfd/S. Sude/	Pang/Searcy 6316	161.00		Wood H-Fr	72.01		1
14	Newport	Searcy Price 6361	161.00		Wood H-Fr	28.03	7.98	1
15	Parkin	WM WM Gateway Tap 6339	161.00		Wood H-Fr	6.30		1
16	ANO	Russellville East 6302	161.00		Wood H-Fr	10.22	1.71	1
17	Batesville	Norfolk (Mt View Tap) 6304	161.00		Wood H-Fr	21.05		1
18	Conway West	Morrilton East 6307	161.00		Wood H-Fr	15.27		1
19	Batesville	Norfolk 6303	161.00		Wood H-Fr	48.74		1
20	Danville Sub Sta	Tie Lns 6309	161.00		Wood H-Fr	0.03		1
21	Hamlet SW	Heber Springs/Grs Fry 6310	161.00		Wood H-Fr	35.21		1
22	Harrison East	Quitman 6313	161.00		Wood H-Fr	80.34		1
23	Gold Creek SW State Line	Sylvan Hills 6312	161.00		Wood H-Fr	19.69		1
24	Newport	Batesville (via ISES) 6331	161.00		Wood H-Fr	19.65	7.77	1
25	Norfolk	Ozk Bch (B: SHLS Tap) 6335	161.00		Wood H-Fr	90.41		1
26	Jonesboro	Parkin (Hrsbrg Tap) 6318	161.00		Wood H-Fr	18.17		1
27	ANO	Morrilton East 6301	161.00		Wood H-Fr	39.37		1
28	ISES	NEWPORT #3 6716	161.00		Sng Concr	11.28		1
29	Pleasant Hill	Quitman 6371	161.00		Sng Concr	20.45		1
30	Grandview	Osage Creek 0874	161.00		Sng Concr	5.21		1
31	West Memphis	Ebony 0810	161.00		Sng Concr	8.76		1
32	Ebony SS	Kuhn Road 0811	161.00		Sng Concr	2.43		1
33	West Memphis	Ebony 0812	161.00		Sng Concr	6.45		1
34	Hamlet	Holland Bottom 0819	161.00		Sng Concr	21.20		1
35	Bald Knob	Tetc P Sta # 6 6652	161.00		Wood H-Fr	1.60		1
36					TOTAL	4,784.34	158.26	214

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Datto	Corning-Tet Sta 8 6696	161.00		VARIOUS	39.65		1
2		Total 161kv Lines						
3								
4		Total 115			Various	2,075.52	109.39	112
5		Arklahoma - Danville				56.70		1
6		(Leased)						
7								
8		Total 69kv			Wood H-Fr	1.66		1
9								
10	Transmission Lines							
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,784.34	158.26	214

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR								1
954 ACSR								2
954 ACSR								3
954 ACSR								4
954 ACSR								5
954 ACSR								6
954 ACSR								7
954 ACSR								8
954 ACSR								9
954 ACSR								10
954 ACSR								11
954 ACSR								12
954 ACSR								13
954 ACSR								14
954 ACSR								15
954 ACSR								16
954 ACSR								17
954 ACSR								18
954 ACSR								19
954 ACSR								20
	37,672,529	280,296,166	317,968,695					21
								22
1024.5 ACAR								23
	934,580	2,733,426	3,668,006					24
								25
1534 ACAR								26
1272 ACSR								27
3070 AACSR								28
1534 ACAR								29
1272 ACSR								30
3070 AACSR								31
1272 ACSR								32
1272 ACSR								33
1272 ACSR								34
	4,958,452	64,528,971	69,487,423					35
	112,528,522	995,598,063	1,108,126,585	12,798,991	6,323,686	52,850	19,175,527	36

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
666 ACSR								2
336 ACSR								3
336 ACSR								4
336 ACSR								5
1272 ACSR								6
954 ACSR								7
336 ACSR								8
1590 ACSR								9
666 ACSR								10
636 ACSR								11
666 ACSR								12
1590 ACSR								13
1590 ACSR								14
1272 ACSR								15
336 ACSR								16
336 ACSR								17
336 ACSR								18
954 ACSR								19
666 ACSR								20
1534 ACAR								21
336 ACSR								22
336 ACSR								23
666 ACSR								24
666 ACSR								25
954 ACSR								26
666 ACSR								27
666 ACSR								28
1590 ACSR								29
336 ACSR								30
666 ACSR								31
336 ACSR								32
336 ACSR								33
336 ACSR								34
666 ACSR								35
	112,528,522	995,598,063	1,108,126,585	12,798,991	6,323,686	52,850	19,175,527	36

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
336 ACSR								1
666 ACSR								2
336 ACSR								3
666 ACSR								4
336 ACSR								5
666 ACSR								6
666 ACSR								7
666 ACSR								8
666 ACSR								9
1590 ACSR								10
666 ACSR								11
1534 ACAR								12
666 ACSR								13
1590 ACSR								14
336 ACSR								15
1534 ACAR								16
336 ACSR								17
666 ACSR								18
336 ACSR								19
666 ACSR								20
666 ACSR								21
666 ACSR								22
666 ACSR								23
1590 ACSR								24
250 CU								25
666 ACSR								26
1024 ACAR								27
1590 ACSR								28
954 ACSR								29
666 ACSS								30
666 ACSS								31
666 ACSS								32
666 ACSS								33
666 ACSR								34
666 ACSR								35
	112,528,522	995,598,063	1,108,126,585	12,798,991	6,323,686	52,850	19,175,527	36

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
VARIOUS								1
	28,506,063	296,935,424	325,441,487					2
								3
	40,413,378	350,884,206	391,297,584					4
								5
								6
								7
	43,520	219,870	263,390					8
								9
				12,798,991	6,323,686	52,850	19,175,527	10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	112,528,522	995,598,063	1,108,126,585	12,798,991	6,323,686	52,850	19,175,527	36

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2017/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
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
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ALCOA ROAD	Distrib. Unattended	115.00	13.80	
2	ALMYRA	Distrib. Unattended	115.00	13.80	
3	ALTHEIMER	Distrib. Unattended	115.00	13.80	
4	AMITY	Distrib. Unattended	115.00	13.80	
5	ANTOINE	Distrib. Unattended	34.50	12.40	
6	ARKADELPHIA NORTH	Distrib. Unattended	115.00	13.80	
7	ARKADELPHIA WEST	Distrib. Unattended	115.00	13.80	
8	ARKLAHOMA	Distrib. Unattended	115.00	13.80	
9	ARMOREL	Distrib. Unattended	34.50	12.40	
10	ATKINS	Distrib. Unattended	161.00	13.80	
11	BALD KNOB	Distrib. Unattended	161.00	13.80	
12	BARTON	Distrib. Unattended	115.00	13.80	
13	BATESVILLE (APL)	Distrib. Unattended	161.00	13.80	
14	BAUCUM	Distrib. Unattended	115.00	13.80	
15	BAUXITE	Distrib. Unattended	115.00	13.80	
16	BEARDEN	Distrib. Unattended	115.00	13.80	
17	BEEBE	Distrib. Unattended	115.00	13.80	
18	BEIRNE	Distrib. Unattended	115.00	13.80	
19	BENTON NORTH	Distrib. Unattended	115.00	13.80	
20	BENTON SOUTH	Distrib. Unattended	115.00	13.80	
21	BERRYVILLE	Distrib. Unattended	161.00	13.80	
22	BIGGERS	Distrib. Unattended	34.50	4.80	
23	BISMARCK	Distrib. Unattended	115.00	13.80	
24	BLACK OAK	Distrib. Unattended	34.50	12.40	
25	BLACK ROCK	Distrib. Unattended	34.50	12.40	
26	BLYTHEVILLE AFB	Distrib. Unattended	34.50	12.40	
27	BLYTHEVILLE EAST END	Distrib. Unattended	34.50	12.40	
28	BLYTHEVILLE ELM ST.	Distrib. Unattended	161.00	12.40	
29	BLYTHEVILLE FLAT LAKE	Distrib. Unattended	34.50	12.40	
30	BLYTHEVILLE I-55	Distrib. Unattended	161.00	34.50	
31	BLYTHEVILLE PLANT	Distrib. Unattended	34.50	4.80	
32	BLYTHEVILLE N.EAST	Distrib. Unattended	34.50	12.40	
33	BLYTHEVILLE N.WEST	Distrib. Unattended	34.50	12.40	
34	BLYTHEVILLE S.WEST	Distrib. Unattended	34.50	12.40	
35	BONO	Distrib. Unattendatd	161.00	13.80	
36	BRINKLEY EAST	Distrib. Unattended	115.00	13.80	
37	BRINKLEY WEST	Distrib. Unattended	115.00	13.80	
38	BRYANT	Distrib. Unattended	115.00	13.80	
39	BULL SHOALS	Distrib. Unattended	161.00	13.80	
40	BUTLER HALL, 4470	Distrib. Unattended	34.50	12.40	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BUTTERFIELD	Distrib. Unattended	115.00	13.80	
2	CABOT (APL)	Distrib. Unattended	115.00	13.80	
3	CALICO ROCK	Distrib. Unattended	161.00	13.80	
4	CAMDEN MAGUIRE	Distrib. Unattended	115.00	13.80	
5	CAMDEN NORTH	Distrib. Unattended	115.00	13.80	
6	CAMPBELL	Distrib. Unattended	34.50	12.40	
7	CARLISLE (APL)	Distrib. Unattended	115.00	13.80	
8	CARPENTER DAM	Distrib. Unattended	115.00	13.80	
9	CARTHAGE (APL)	Distrib. Unattended	115.00	13.80	
10	CASH	Distrib. Unattended	161.00	13.80	
11	CAVE CITY	Distrib. Unattended	161.00	34.50	
12	CEDAR GROVE	Distrib. Unattended	161.00	13.80	
13	CHERRY VALLEY	Distrib. Unattended	161.00	13.80	
14	CLARENDON	Distrib. Unattended	115.00	13.80	
15	CLINTON (APL)	Distrib. Unattended	161.00	13.80	
16	COFER ROAD	Distrib. Unattended	161.00	13.80	
17	COLLEGE CITY	Distrib. Unattended	34.50	12.40	
18	CONWAY INDUSTRIAL CO	Distrib. Unattended	161.00	13.80	
19	CONWAY SOUTH CO	Distrib. Unattended	161.00	13.80	
20	CONWAY WEST CO	Distrib. Unattended	161.00	13.80	
21	CORNING 115	Distrib. Unattended	115.00	34.50	
22	CORNING 34.5	Distrib. Unattended	34.50	12.40	
23	COTTON PLANT	Distrib. Unattended	115.00	13.80	
24	COTTON PLANT CITY 4160	Distrib. Unattended	13.80	4.80	
25	COUCH SES SWITCHYARD	Distrib. Unattended	115.00	13.80	
26	CROOKED LAKE	Distrib. Unattended	161.00	34.50	
27	CROSSETT NORTH	Distrib. Unattended	115.00	13.80	
28	CROSSETT PAPER MILL	Distrib. Unattended	115.00	13.80	
29	CROSSETT WEST	Distrib. Unattended	115.00	13.80	
30	CUSHMAN	Distrib. Unattended	161.00	13.80	
31	DALARK	Distrib. Unattended	115.00	34.50	
32	DANVILLE (APL)	Distrib. Unattended	161.00	13.80	
33	DARDANELLE	Distrib. Unattended	161.00	13.80	
34	DATTO	Distrib. Unattended	115.00	2.40	
35	DELIGHT	Distrib. Unattended	34.50	13.80	
36	DELL CITY	Distrib. Unattended	34.50	2.40	
37	DERMOTT	Distrib. Unattended	115.00	13.80	
38	DES ARC	Distrib. Unattended	115.00	13.80	
39	DEVALLS BLUFF	Distrib. Unattended	115.00	13.80	
40	DEWITT	Distrib. Unattended	115.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	DIAMOND CITY	Distrib. Unattended	34.50	13.80	
2	DUMAS	Distrib. Unattended	115.00	13.80	
3	EL DORADO DONAN	Distrib. Unattended	115.00	13.80	
4	EL DORADO EAST	Distrib. Unattended	115.00	13.80	
5	EL DORADO JACKSON	Distrib. Unattended	115.00	13.80	
6	EL DORADO LION OIL	Distrib. Unattended	115.00	13.80	
7	EL DORADO MILL ROAD	Distrib. Unattended	115.00	13.80	
8	EL DORADO MONSANTO	Distrib. Unattended	115.00	13.80	
9	EL DORADO NEWELL	Distrib. Unattended	115.00	13.80	
10	EL DORADO PARKERS CHAPEL	Distrib. Unattended	115.00	13.80	
11	EL DORADO PARNELL ROAD	Distrib. Unattended	115.00	13.80	
12	EL DORADO QUINN	Distrib. Unattended	115.00	13.80	
13	EL DORADO UPLAND	Distrib. Unattended	115.00	13.80	
14	EL DORADO WEST	Distrib. Unattended	115.00	13.80	
15	ELAINE	Distrib. Unattended	115.00	13.80	
16	EMERSON	Distrib. Unattended	115.00	13.80	
17	ENGLAND	Distrib. Unattended	115.00	13.80	
18	EUDORA	Distrib. Unattended	161.00	34.50	
19	EVERTON ROAD	Distrib. Unattended	161.00	13.80	
20	FAULKNER LAKE (NLR)	Distrib. Unattended	115.00	13.80	
21	FISHER	Distrib. Unattended	161.00	13.80	
22	FLIPPIN	Distrib. Unattended	161.00	13.80	
23	FORDYCE	Distrib. Unattended	115.00	13.80	
24	FORDYCE ORIENT	Distrib. Unattended	115.00	13.80	
25	FORREST CITY NORTH	Distrib. Unattended	161.00	13.80	
26	FORREST CITY SOUTH	Distrib. Unattended	161.00	13.80	
27	FOUNTAIN LAKE	Distrib. Unattended	115.00	13.80	
28	FRIENDSHIP	Distrib. Unattended	115.00	13.80	
29	GIFFORD	Distrib. Unattended	115.00	13.80	
30	GILLETT	Distrib. Unattended	115.00	13.80	
31	GILMORE	Distrib. Unattended	161.00	13.80	
32	GLEASON	Distrib. Unattended	161.00	13.80	
33	GLENWOOD	Distrib. Unattended	115.00	13.80	
34	GLENWOOD PUMPING PLANT	Distrib. Unattended	13.80	2.40	
35	GREEN FOREST	Distrib. Unattended	161.00	13.80	
36	GREEN FOREST SOUTH	Distrib. Unattended	161.00	13.80	
37	GREENBRIER	Distrib. Unattended	161.00	13.80	
38	GREENWAY	Distrib. Unattended	34.50	4.80	
39	GRIFFITHVILLE	Distrib. Unattended	115.00	13.80	
40	GUION	Distrib. Unattended	161.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	GURDON	Distrib. Unattended	115.00	13.80	
2	H.S. ALBRIGHT	Distrib. Unattended	115.00	13.80	
3	H.S. EAST	Distrib. Unattended	115.00	13.80	
4	H.S. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
5	H.S. MILTON	Distrib. Unattended	115.00	13.80	
6	H.S. MT. VALLEY	Distrib. Unattended	115.00	13.80	
7	H.S. NORTH	Distrib. Unattended	115.00	13.80	
8	H.S. ROYAL	Distrib. Unattended	115.00	13.80	
9	H.S. SOUTH	Distrib. Unattended	115.00	13.80	
10	H.S. UNION CARBIDE	Distrib. Unattended	115.00	13.80	
11	H.S. VALLEY STREET	Distrib. Unattended	115.00	13.80	
12	H.S. VILLAGE	Distrib. Unattended	115.00	13.80	
13	H.S. WEST	Distrib. Unattended	115.00	13.80	
14	HAMBURG	Distrib. Unattended	115.00	13.80	
15	HAMLET	Distrib. Unattended	161.00	2.40	
16	HARDIN WEST	Distrib. Unattended	115.00	13.80	
17	HARDY NORTH	Distrib. Unattended	161.00	13.80	
18	HARRISBURG	Distrib. Unattended	161.00	13.80	
19	HARRISON EAST	Distrib. Unattended	161.00	13.80	
20	HARRISON WEST	Distrib. Unattended	161.00	13.80	
21	HASKELL	Distrib. Unattended	115.00	13.80	
22	HAYS CITY	Distrib. Unattended	115.00	13.80	
23	HAZEN	Distrib. Unattended	115.00	13.80	
24	HEBER SPRINGS INDUSTRIAL	Distrib. Unattended	161.00	13.80	
25	HEBER SPRINGS SOUTH	Distrib. Unattended	161.00	13.80	
26	HELENA CENTRAL	Distrib. Unattended	115.00	13.80	
27	HELENA SOUTH	Distrib. Unattended	115.00	13.80	
28	HENSLEY	Distrib. Unattended	115.00	13.80	
29	HERMITAGE (APL)	Distrib. Unattended	115.00	13.80	
30	HIGHLAND (APL)	Distrib. Unattended	161.00	13.80	
31	HIGHWAY #7	Distrib. Unattended	34.50	13.80	
32	HILO	Distrib. Unattended	115.00	13.80	
33	HUGHES	Distrib. Unattended	161.00	13.80	
34	HUTTIG	Distrib. Unattended	115.00	13.80	
35	IMBODEN	Distrib. Unattended	69.00	34.50	
36	IMBODEN JUNCTION	Distrib. Unattended	34.50	12.40	
37	INDEPENDENCE-ISES-SWITCHYARD	Distrib. Unattended	161.00	13.80	
38	JACKSONVILLE NORTH	Distrib. Unattended	115.00	13.80	
39	JACKSONVILLE SOUTH	Distrib. Unattended	115.00	13.80	
40	JEFFERSON INDUSTRIAL	Distrib. Unattended	115.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	JIM HILL	Distrib. Unattended	115.00	34.50	
2	JONESBORO (APL)	Distrib. Unattended	161.00	13.80	
3	KERLIN	Distrib. Unattended	115.00	13.80	
4	KINGSLAND	Distrib. Unattended	115.00	13.80	
5	KUHN ROAD	Distrib. Unattended	161.00	13.80	
6	L.R. 145TH ST	Distrib. Unattended	115.00	13.80	
7	L.R. 23RD & SPRING	Distrib. Unattended	115.00	13.80	
8	L.R. 8TH & WOODROW	Distrib. Unattended	115.00	13.80	
9	L.R. ALEXANDER	Distrib. Unattended	115.00	13.80	
10	L.R. ARCH ST.	Distrib. Unattended	115.00	13.80	
11	L.R. BOYLE PARK	Distrib. Unattended	115.00	13.80	
12	L.R. BRINGLE	Distrib. Unattended	161.00	13.80	
13	L.R. CAMMACK	Distrib. Unattended	115.00	13.80	
14	L.R. CHICOT	Distrib. Unattended	115.00	13.80	
15	L.R. EAST	Distrib. Unattended	115.00	13.80	
16	L.R. FOURCHE	Distrib. Unattended	115.00	13.80	
17	L.R. GAINES	Distrib. Unattended	115.00	13.80	
18	L.R. GARLAND	Distrib. Unattended	115.00	13.80	
19	L.R. HINDMAN	Distrib. Unattended	115.00	13.80	
20	L.R. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
21	L.R. KANIS RD	Distrib. Unattended	115.00	13.80	
22	L.R. MANN	Distrib. Unattended	115.00	13.80	
23	L.R. PINNACLE	Distrib. Unattended	115.00	13.80	
24	L.R. PORT	Distrib. Unattended	115.00	13.80	
25	L.R. ROCK CREEK	Distrib. Unattended	115.00	13.80	
26	L.R. ROLAND ROAD	Distrib. Unattended	115.00	13.80	
27	L.R. SOUTH	Distrib. Unattended	115.00	13.80	
28	L.R. WALTON HEIGHTS	Distrib. Unattended	115.00	13.80	
29	L.R. WEST	Distrib. Unattended	115.00	13.80	
30	L.R. WEST MARKHAM	Distrib. Unattended	115.00	13.80	
31	LAKE CHICOT PUMP STA	Distrib. Unattended	115.00	4.80	
32	LAKE CONWAY	Distrib. Unattended	115.00	13.80	
33	LAKE VILLAGE BAGBY	Distrib. Unattended	115.00	13.80	
34	LAKEWOOD (NLR)	Distrib. Unattended	115.00	13.80	
35	LAMARTINE	Distrib. Unattended	115.00	13.80	
36	LAWSON ROAD	Distrib. Unattended	115.00	13.80	
37	LEACHVILLE	Distrib. Unattended	34.50	12.40	
38	LEPANTO	Distrib. Unattended	161.00	13.80	
39	LEWISVILLE	Distrib. Unattended	115.00	13.80	
40	LONDON	Distrib. Unattended	161.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	LONOKE EAST	Distrib. Unattended	115.00	13.80	
2	LUNSFORD	Distrib. Unattended	69.00	13.80	
3	MABELVALE EHV	Distrib. Unattended	115.00	13.80	
4	MACEDONIA	Distrib. Unattended	115.00	13.80	
5	MAGNOLIA DOW	Distrib. Unattended	115.00	13.80	
6	MAGNOLIA EAST	Distrib. Unattended	115.00	13.80	
7	MAGNOLIA SOUTH	Distrib. Unattended	115.00	13.80	
8	MAGNOLIA STEEL	Distrib. Unattended	115.00	13.80	
9	MAGNOLIA WEST	Distrib. Unattended	115.00	13.80	
10	MALVERN NORTH	Distrib. Unattended	115.00	13.80	
11	MALVERN SOUTH	Distrib. Unattended	115.00	13.80	
12	MANILA	Distrib. Unattended	34.50	12.40	
13	MANSON 34.5	Distrib. Unattended	34.50	2.40	
14	MARIANNA	Distrib. Unattended	115.00	13.80	
15	MARION	Distrib. Unattended	161.00	13.80	
16	MARKED TREE	Distrib. Unattended	161.00	13.80	
17	MARMADUKE	Distrib. Unattended	34.50	12.40	
18	MARMADUKE ARI	Distrib. Unattended	34.50	12.40	
19	MARMADUKE RAIL 161KV	Distrib. Unattended	161.00	34.50	
20	MARSHALL	Distrib. Unattended	161.00	13.80	
21	MARVELL	Distrib. Unattended	115.00	13.80	
22	MAUMELLE EAST	Distrib. Unattended	115.00	13.80	
23	MCALMONT	Distrib. Unattended	115.00	13.80	
24	MCCRORY	Distrib. Unattended	161.00	13.80	
25	MCGEHEE	Distrib. Unattended	115.00	13.80	
26	MCNEIL EHV	Distrib. Unattended	115.00	13.80	
27	MELBOURNE	Distrib. Unattended	161.00	13.80	
28	MONETTE	Distrib. Unattended	34.50	12.40	
29	MONETTE JUNCTION	Distrib. Unattended	161.00	34.50	
30	MONTICELLO EAST	Distrib. Unattended	115.00	13.80	
31	MONTICELLO SOUTH	Distrib. Unattended	115.00	13.80	
32	MONTROSE	Distrib. Unattended	115.00	13.80	
33	MOOREFIELD	Distrib. Unattended	161.00	13.80	
34	MORELAND	Distrib. Unattended	161.00	13.80	
35	MORGAN	Distrib. Unattended	115.00	13.80	
36	MORO	Distrib. Unattended	115.00	13.80	
37	MORRILTON EAST	Distrib. Unattended	161.00	13.80	
38	MORRILTON WEST	Distrib. Unattended	161.00	13.80	
39	MOUNT PLEASANT	Distrib. Unattended	161.00	13.80	
40	MOUNTAIN HOME	Distrib. Unattended	161.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MOUNTAIN VIEW	Distrib. Unattended	161.00	13.80	
2	MT IDA	Distrib. Unattended	115.00	13.80	
3	MT PINE NORTH	Distrib. Unattended	115.00	13.80	
4	MT PINE SOUTH	Distrib. Unattended	115.00	13.80	
5	N.L.R. DIXIE	Distrib. Unattended	115.00	13.80	
6	N.L.R. LEVY	Distrib. Unattended	115.00	13.80	
7	N.L.R. MCCAIN	Distrib. Unattended	115.00	13.80	
8	N.L.R. WESTGATE	Distrib. Unattended	115.00	13.80	
9	NEWARK	Distrib. Unattended	161.00	13.80	
10	NEWPORT	Distrib. Unattended	161.00	13.80	
11	NEWPORT AB	Distrib. Unattended	161.00	13.80	
12	NEWPORT IND	Distrib. Unattended	161.00	13.80	
13	OLA	Distrib. Unattended	115.00	13.80	
14	OMAHA	Distrib. Unattended	161.00	13.80	
15	OSCEOLA	Distrib. Unattended	161.00	13.80	
16	OSCEOLA INDUSTRIAL	Distrib. Unattended	161.00	13.80	
17	OSCEOLA NORTH	Distrib. Unattended	161.00	13.80	
18	P.B. 34TH & MAIN	Distrib. Unattended	115.00	13.80	
19	P.B. ARSENAL D	Distrib. Unattended	115.00	13.80	
20	P.B. DIERKS	Distrib. Unattended	115.00	13.80	
21	P.B. EAST	Distrib. Unattended	115.00	13.80	
22	P.B. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
23	P.B. MCCAMANT	Distrib. Unattended	115.00	13.80	
24	P.B. PORT	Distrib. Unattended	115.00	13.80	
25	P.B. SOUTH	Distrib. Unattended	115.00	13.80	
26	P.B. WATSON CHAPEL	Distrib. Unattended	115.00	13.80	
27	P.B. WEST	Distrib. Unattended	115.00	13.80	
28	P.B. WHITEHALL	Distrib. Unattended	115.00	13.80	
29	PANGBURN	Distrib. Unattended	161.00	13.80	
30	PARAGOULD	Distrib. Unattended	115.00	12.40	
31	PARKIN	Distrib. Unattended	161.00	13.80	
32	POCAHONTAS NORTH	Distrib. Unattended	161.00	12.40	
33	POCAHONTAS SOUTH	Distrib. Unattended	34.50	12.40	
34	PORTIA	Distrib. Unattended	34.50	2.40	
35	POYEN	Distrib. Unattended	115.00	13.80	
36	PRESCOTT	Distrib. Unattended	115.00	13.80	
37	PROMISED LAND	Distrib. Unattended	34.50	12.40	
38	QUITMAN	Distrib. Unattended	161.00	13.80	
39	RECTOR	Distrib. Unattended	161.00	12.40	
40	REYNO	Distrib. Unattended	34.50	4.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	RICHWOOD	Distrib. Unattended	115.00	13.80	
2	RISON	Distrib. Unattended	115.00	13.80	
3	RITCHIE SES PLANT	Distrib. Unattended	230.00	13.80	
4	ROHWER	Distrib. Unattended	115.00	13.80	
5	RUSSELLVILLE EAST	Distrib. Unattended	161.00	13.80	
6	RUSSELLVILLE NORTH	Distrib. Unattended	161.00	13.80	
7	RUSSELLVILLE SOUTH	Distrib. Unattended	161.00	13.80	
8	RUTHERFORD	Distrib. Unattended	161.00	13.80	
9	SC LITTLE ROCK	Distrib. Unattended	34.50	12.40	
10	SEARCY PRICE	Distrib. Unattended	115.00	13.80	
11	SEARCY SOUTH	Distrib. Unattended	161.00	13.80	
12	SHERIDAN	Distrib. Unattended	115.00	13.80	
13	SHERRILL	Distrib. Unattended	115.00	13.80	
14	SHERWOOD	Distrib. Unattended	115.00	13.80	
15	SHOFFNER	Distrib. Unattended	161.00	13.80	
16	SHULER	Distrib. Unattended	115.00	13.80	
17	SMACKOVER	Distrib. Unattended	115.00	13.80	
18	SMACKOVER INDUSTRIAL	Distrib. Unattended	115.00	13.80	
19	SOUTH LEAD HILL	Distrib. Unattended	161.00	34.50	
20	SOUTHSIDE	Distrib. Unattended	161.00	13.80	
21	ST. FRANCIS	Distrib. Unattended	34.50	2.40	
22	ST. JOE	Distrib. Unattended	161.00	13.80	
23	ST. VINCENT	Distrib. Unattended	161.00	13.80	
24	STEPHENS	Distrib. Unattended	115.00	13.80	
25	STRAWBERRY	Distrib. Unattended	13.80	2.40	
26	STRONG	Distrib. Unattended	115.00	13.80	
27	STUTTGART INDUSTRIAL	Distrib. Unattended	115.00	13.80	
28	STUTTGART NORTH	Distrib. Unattended	115.00	13.80	
29	STUTTGART RICUSKEY	Distrib. Unattended	115.00	13.80	
30	SUMMIT	Distrib. Unattended	161.00	13.80	
31	SWIFTON	Distrib. Unattended	161.00	13.80	
32	TAYLOR	Distrib. Unattended	115.00	13.80	
33	THAYER NORTH	Distrib. Unattended	69.00	4.80	
34	TRUMANN	Distrib. Unattended	161.00	13.80	
35	TWIST	Distrib. Unattended	161.00	13.80	
36	ULM	Distrib. Unattended	115.00	13.80	
37	VARNER	Distrib. Unattended	115.00	13.80	
38	VILONIA	Distrib. Unattended	161.00	13.80	
39	WABBASEKA	Distrib. Unattended	115.00	13.80	
40	WALCOTT	Distrib. Unattended	34.50	12.40	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	WALNUT RIDGE NORTH	Distrib. Unattended	34.50	12.40	
2	WALNUT RIDGE PLANT	Distrib. Unattended	34.50	12.40	
3	WALNUT RIDGE W/161	Distrib. Unattended	161.00	12.40	
4	WARREN EAST	Distrib. Unattended	115.00	13.80	
5	WARREN WEST	Distrib. Unattended	115.00	13.80	
6	WEST HELENA	Distrib. Unattended	115.00	13.80	
7	WEST MEMPHIS DOVER	Distrib. Unattended	161.00	13.80	
8	WEST MEMPHIS GATEWAY	Distrib. Unattended	161.00	13.80	
9	WEST MEMPHIS LEHI	Distrib. Unattended	161.00	13.80	
10	WHELEN SPRINGS	Distrib. Unattended	34.50	12.40	
11	WHITE BLUFF EHV	Distrib. Unattended	115.00	13.80	
12	WILMAR	Distrib. Unattended	115.00	13.80	
13	WILMOT	Distrib. Unattended	34.50	13.80	
14	WILSON	Distrib. Unattended	161.00	13.80	
15	WOODWARD	Distrib. Unattended	115.00	13.80	
16	WYNNE CITY 4160	Distrib. Unattended	13.80	4.80	
17	WYNNE INDUSTRIAL	Distrib. Unattended	161.00	13.80	
18	WYNNE SOUTH	Distrib. Unattended	161.00	13.80	
19	AECC BALCH	Trans Unattended	161.00	161.00	
20	ANO SWITCHYARD	Trans Unattended	500.00	161.00	
21	BALD KNOB-TEXAS EASTERN T.C. P.S. #6 SS	Trans Unattended	161.00	115.00	
22	BENTON WEST	Trans Unattended	161.00	161.00	
23	BRINKLEY EAST	Trans Unattended	230.00	115.00	
24	CONWAY WEST	Trans Unattended	161.00	115.00	
25	DANVILLE (APL)	Trans Unattended	161.00	115.00	
26	DATTO	Trans Unattended	161.00	115.00	
27	DELL EHV	Trans Unattended	500.00	161.00	
28	Driver	Trans Unattended	500.00	230.00	
29	EL DORADO EHV	Trans Unattended	500.00	115.00	
30	Goodwin	Trans Unattended	115.00	115.00	
31	H.S. EHV	Trans Unattended	500.00	115.00	
32	Hurricane Lake	Trans Unattended	115.00	115.00	
33	INDEPENDENCE-ISES	Trans Unattended	500.00	161.00	
34	JIM HILL	Trans Unattended	161.00	115.00	
35	L.R. PINNACLE	Trans Unattended	161.00	115.00	
36	LAKE VILLAGE BAGBY	Trans Unattended	230.00	115.00	
37	MABELVALE EHV	Trans Unattended	500.00	115.00	
38	MAYFLOWER EHV	Trans Unattended	500.00	115.00	
39	MCNEIL EHV	Trans Unattended	500.00	115.00	
40	MOSES SES	Trans. Unattended	161.00	115.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MURFREESBORO SOUTH	Trans Unattended	138.00	115.00	
2	PARAGOULD	Trans Unattended	161.00	115.00	
3	PLEASANT HILL	Trans Unattended	500.00	161.00	
4	Powerline Road	Trans. Unattended	500.00	161.00	
5	RITCHIE SES SWITCHYARD	Trans Unattended	230.00	115.00	
6	SEARCY PRICE	Trans Unattended	161.00	115.00	
7	STUTTGART RICUSKEY	Trans Unattended	230.00	115.00	
8	SYLVAN HILLS	Trans Unattended	161.00	115.00	
9	THAYER SOUTH	Trans Unattended	161.00	69.00	
10	WALNUT RIDGE W/161	Trans Unattended	161.00	115.00	
11	WATER VALLEY	Trans Unattended	161.00	69.00	
12	WEST MEMPHIS EHV	Trans Unattended	500.00	161.00	
13	WHITE BLUFF EHV	Trans Unattended	500.00	115.00	
14	WOODWARD	Trans Unattended	230.00	115.00	
15	WRIGHTSVILLE	Trans Unattended	500.00	115.00	
16	Total Capacity		50743.70	9330.10	
17					
18	Distribution Unattended 338				
19	Transmission Unattended 37				
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
67	2					1
10	1					2
13	1					3
23	2					4
2	3					5
30	1					6
30	1					7
20	1	1				8
18	2					9
40	2					10
34	1					11
7	1					12
93	3					13
13	1					14
25	1					15
13	1					16
34	1					17
17	1					18
34	1					19
30	1					20
53	2					21
1	3	1				22
13	1					23
5	1					24
3	1	6				25
30	3					26
11	1					27
87	3	1				28
4	1					29
75	2					30
23	2					31
18	2					32
18	2					33
11	1					34
40	1					35
26	2					36
33	1					37
34	1					38
20	1					39
2	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
13	1					1
53	2					2
10	1					3
20	1					4
53	2					5
13	1					6
20	1					7
33	1					8
13	1					9
22	1					10
14	1					11
7	1					12
20	1					13
13	1					14
20	1					15
40	1					16
11	1					17
83	2					18
84	2					19
100	2					20
37	1					21
15	2					22
7	1	1				23
	1					24
13	1					25
33	1					26
67	2					27
64	2					28
34	1					29
7	1					30
7	1					31
22	1					32
67	2					33
13	4					34
6	1					35
2	3					36
20	1					37
13	1					38
7	1					39
25	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	1					1
63	3					2
63	2					3
50	2					4
63	2					5
30	1					6
20	1					7
20	1					8
20	1					9
20	1					10
50	1					11
13	1					12
53	2					13
34	1					14
13	1					15
13	1					16
25	2					17
20	1					18
25	1					19
50	1					20
20	1					21
20	1					22
30	2					23
33	1					24
42	2					25
22	1					26
33	1					27
6	1					28
41	2					29
13	1					30
5	1					31
42	2					32
22	1					33
3	1					34
20	1					35
30	1					36
30	1					37
1	3					38
7	1					39
7	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
23	2					1
50	1					2
5	1					3
13	1					4
34	1					5
20	1					6
30	1					7
33	1					8
67	2					9
20	1					10
64	2					11
54	2					12
34	1					13
13	2					14
57	3					15
5	1					16
33	1					17
20	1					18
63	2					19
97	3					20
40	2					21
16	1					22
20	1					23
33	1					24
22	1					25
20	1					26
20	1					27
10	1					28
7	1					29
30	1					30
13	1					31
5	1					32
22	1					33
13	1					34
8	1					35
4	3					36
20	1					37
89	2					38
30	1					39
40	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
33	1	1				1
22	1					2
33	2					3
3	1					4
33	1					5
20	1					6
34	1					7
100	2					8
63	2					9
30	1					10
63	2					11
3	1					12
34	1					13
64	2					14
67	2					15
34	1					16
100	2					17
112	2					18
34	1					19
80	2					20
66	2					21
20	1					22
33	1					23
67	2					24
67	2					25
13	1					26
55	2					27
83	2					28
100	2					29
162	3					30
60	2					31
37	1					32
34	1					33
33	1					34
23	2					35
50	1					36
13	1					37
22	1					38
22	1					39
10	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
30	1					1
11	1					2
50	1	4				3
33	1					4
13	1					5
33	1					6
33	1					7
13	1					8
34	1					9
30	1					10
47	2					11
11	1					12
2	3					13
20	1					14
47	2					15
22	1					16
5	1	4				17
11	1					18
33	1					19
20	1					20
12	2					21
67	2					22
67	2					23
20	1					24
30	1					25
20	1					26
22	1					27
5	1					28
75	2					29
34	1					30
30	1					31
47	2					32
46	2					33
20	1					34
63	2					35
7	1					36
34	1					37
30	1					38
10	1					39
56	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
42	2					1
42	2					2
20	1					3
33	1					4
50	1	1				5
83	2					6
33	1					7
64	2					8
10	1					9
34	1					10
22	1					11
92	3					12
53	3					13
35	5					14
44	2					15
30	1					16
33	1					17
30	1					18
15	2					19
34	1					20
60	2					21
58	2					22
64	2					23
33	1					24
20	1					25
64	2					26
3	1					27
34	1					28
20	1					29
26	4					30
20	1					31
44	2					32
13	1					33
2	1	1				34
26	2	1				35
42	2					36
1	2					37
22	1					38
48	2					39
1	3					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
7	1					1
9	1					2
375	1					3
46	2					4
100	2					5
83	2					6
80	2					7
67	2					8
2	2	5				9
84	2					10
84	2					11
30	1					12
7	1					13
106	2					14
5	1					15
33	2					16
13	1					17
33	1					18
20	1					19
20	1					20
1	3					21
3	1					22
20	1					23
10	1					24
4	1					25
13	1					26
33	1					27
30	1					28
60	2					29
42	2					30
25	2					31
4	1					32
7	2					33
20	1					34
5	1					35
20	1					36
25	2					37
40	1					38
13	1					39
1	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
11	1					1
20	1					2
72	3					3
25	2					4
20	1					5
34	1					6
34	1					7
30	1					8
56	2					9
3	1					10
45	2					11
7	1					12
20	1					13
20	1					14
33	1	1				15
	1					16
45	2					17
20	1					18
						19
896	4					20
50	1					21
						22
616	3					23
224	1					24
125	1					25
225	1					26
672	3	1				27
						28
1344	6	2				29
						30
1100	2					31
						32
850	2					33
112	1					34
225	1					35
448	1					36
895	6	2				37
1260	3					38
600	3	1				39
165	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
150	1					1
125	1					2
800	4					3
						4
180	1					5
225	1					6
448	1					7
140	1					8
50	1					9
60	3	1				10
50	1					11
450	3	1				12
840	2					13
300	1					14
597	4					15
25258	547	36				16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2017/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

- 1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
- 2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
- 3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	See footnote for schedule details			
3	See footnote for the allocation methods details			
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column: a

Entergy service companies, including Entergy Operations, Inc. and Entergy Services, Inc., provide recurring, ongoing services to Entergy affiliates. Service company transactions are reported in the schedule below by type of category, where the amount charged or credited for each category is equal to or greater than the \$250,000 threshold. All other non-service company affiliate transactions reported in this schedule, if any, are reported by individual detailed transaction.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliate			
2	Corporate Support - General	Entergy Operations, Inc.	107000, 163000, 174104, 253107, 42650T, 528000, 926000	(1,423,861)
3	Finance - Risk Management	Entergy Operations, Inc.	107000, 163000, 253107, 408110, 408122, 408123, 408142, 421000, 426300, 426500, 42650T, 4265TX, 517000, 519000, 520000, 524000, 528000, 529000, 530000, 531000, 532000, 904000, 920000, 930200	253,427
4	Nuclear - Regulated	Entergy Operations, Inc.	107000, 174104, 253107, 408110, 42650T, 4265TX, 517000, 524000, 528000, 532000, 920000	123,581,300
5	Nuclear Corporate Support	Entergy Operations, Inc.	107000, 163000, 174104, 408110, 42650T, 4265TX, 517000, 519000, 520000, 524000, 528000, 532000, 920000, 925000	6,519,272
6	Nuclear Operations	Entergy Operations, Inc.	107000, 163000, 174104, 174201, 253107, 408110, 426400, 426500, 42650T, 4265TX, 517000, 519000, 520000, 524000, 528000, 530000, 531000, 532000, 920000, 921000, 926000	7,542,849
7	System Benefits	Entergy Operations, Inc.	107000, 163000, 174104, 408110, 42650T, 4265TX, 517000, 519000, 520000, 524000, 528000, 532000, 920000, 925000	33,218,936
8	Tax And Interest Expense	Entergy Operations, Inc.	408152, 408158, 409112, 409114, 410101, 410120, 411110, 411120, 419000, 419011, 421000, 430000	769,176
9	System Benefits	Entergy Operations, Inc.	107000, 163000, 174104, 253107, 42650T, 524000, 528000, 923000, 926000	32,814,904
10	Utility Management and Support Services	Entergy Operations, Inc.	107000, 163000, 408110, 42650T, 4265TX, 517000, 524000, 532000, 920000	2,466,736

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
--	---	---------------------------------------	----------------------------------

FOOTNOTE DATA

11	Administration	Entergy Services, Inc.	107000, 108220, 174101, 184001, 253053, 253107, 4031AM, 408110, 421000, 4212AM, 426400, 426500, 4265OT, 4265TX, 431000, 454000, 507000, 517000, 520000, 524000, 525000, 546000, 560000, 561200, 561500, 566000, 567000, 568000, 569000, 573000, 580000, 588000, 591000, 909000, 920000, 921000, 923000, 926000, 928000, 930200, 930210, 931000, 935000	4,192,971
12	Capital Project Excellence	Entergy Services, Inc.	107000, 108220, 163000, 174101, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 517000, 560000, 568000, 570000, 920000, 921000, 923000, 926000, 930200, 931000, 935000	2,162,039
13	Chief Administrative Officer	Entergy Services, Inc.	107000, 253107, 408110, 426100, 4265OT, 4265TX, 580000, 920000, 921000, 923000, 935000	509,536
14	Corporate	Entergy Services, Inc.	107000, 163000, 253107, 408110, 4265OT, 4265TX, 920000, 921000, 923000, 926000, 930200, 931000	571,069
15	Corporate - Legal Services	Entergy Services, Inc.	107000, 108220, 152000, 174101, 181CPD, 186080, 253107, 408110, 408152, 426100, 426400, 426500, 4265OT, 4265TX, 500000, 506000, 524000, 525000, 549000, 589000, 910000, 913000, 920000, 921000, 923000, 926000, 928000, 930200, 931000	7,709,530
16	Corporate - Public Relations	Entergy Services, Inc.	107000, 174101, 174104, 253107, 408110, 426100, 426400, 426500, 4265OT, 4265TX, 517000, 524000, 580000, 908000, 909000, 910000, 920000, 921000, 923000, 926000, 930100, 930200, 931000, 935000	3,613,854
17	Corporate Support - General	Entergy Services, Inc.	107000, 108220, 152000, 163000, 174101, 174104, 174200, 181CPD, 184001, 1840FS, 1840NC, 184EST, 228100, 253107, 4031AM, 408110, 408152, 417100, 421000, 426100, 426400, 426500, 4265OT, 4265TX, 430000, 431000, 500000, 506000, 510000, 517000,	17,283,777

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2017/Q4
FOOTNOTE DATA				
		520000, 524000, 528000, 530000, 532000, 556000, 557000, 560000, 561200, 561300, 561500, 566000, 568000, 580000, 588000, 903001, 903002, 904000, 910000, 920000, 921000, 923000, 924000, 925000, 928000, 930200, 935000		
18	Customer Service and Operations Support Entergy Services, Inc.	107000, 184EST, 253107, 408110, 4265OT, 4265TX, 524000, 560000, 561500, 566000, 580000, 588000, 590000, 901000, 903001, 903002, 905000, 907000, 920000, 926000		1,051,028
19	Customer Service Support Entergy Services, Inc.	107000, 174101, 174200, 184001, 184EST, 253107, 408110, 426500, 4265OT, 4265TX, 588000, 901000, 902000, 903001, 903002, 905000, 907000, 908000, 910000, 913000, 916000, 920000, 921000, 923000, 926000, 931000, 935000		7,569,773
20	Distribution Entergy Services, Inc.	107000, 163000, 174101, 184001, 1840NC, 184EST, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 524000, 560000, 566000, 568000, 569000, 580000, 581000, 584000, 586000, 588000, 589000, 590000, 598000, 901000, 903002, 920000, 921000, 926000, 935000		357,678
21	Finance - Finance and Accounting Entergy Services, Inc.	107000, 163000, 174104, 174200, 181CPD, 184001, 184EST, 186080, 253107, 408110, 426100, 426400, 426500, 4265OT, 4265TX, 507000, 517000, 524000, 560000, 580000, 901000, 903002, 905000, 908000, 910000, 920000, 921000, 923000, 924000, 925000, 926000, 928000, 930200, 931000, 935000		12,938,828
22	Fossil Operations Entergy Services, Inc.	107000, 253107, 408110, 4265OT, 4265TX, 566000, 920000, 921000, 923000		9,339,929
23	Human Resources Entergy Services, Inc.	107000, 228100, 253107, 408110, 426100, 4265OT, 4265TX, 517000, 524000, 540000, 560000, 561500, 566000, 580000, 913000, 920000, 921000, 923000, 926000, 930100, 930200,		5,027,070
FERC FORM NO. 1 (ED. 12-87) Page 450.3				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		//	2017/Q4
FOOTNOTE DATA			
		931000	
24	Information Technology Entergy Services, Inc.	107000, 163000, 174101, 174200, 184001, 253107, 408110, 426400, 4265OT, 4265TX, 431000, 454000, 500000, 506000, 517000, 524000, 525000, 532000, 539000, 549000, 560000, 561200, 561500, 566000, 567000, 569100, 573000, 580000, 588000, 589000, 598000, 870000, 903001, 920000, 921000, 923000, 926000, 928000, 930200, 931000, 932000, 935000	62,237,362
25	Nuclear - Non-Regulated Entergy Services, Inc.	107000, 163000, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 517000, 519000, 520000, 524000, 525000, 528000, 532000, 556000, 920000, 921000, 926000, 928000	23,692
26	Nuclear - Regulated Entergy Services, Inc.	107000, 163000, 174104, 1840NC, 253107, 408110, 426400, 426500, 4265OT, 4265TX, 517000, 519000, 520000, 524000, 525000, 528000, 529000, 530000, 531000, 532000, 920000, 921000, 923000, 926000, 928000, 930201	278,669
27	Nuclear Corporate Support Entergy Services, Inc.	107000, 253107, 408110, 4265OT, 4265TX, 517000, 524000, 525000, 528000, 926000	20,276,999
28	Operations and Performance Entergy Services, Inc.	107000, 108220, 174104, 184001, 228100, 253107, 408110, 426400, 426500, 4265OT, 4265TX, 500000, 506000, 517000, 524000, 525000, 532000, 560000, 561200, 561500, 566000, 580000, 920000, 921000, 923000, 926000, 930100, 930200, 931000	2,692,244
29	Supply Chain Entergy Services, Inc.	107000, 108220, 163000, 174101, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 517000, 524000, 546000, 560000, 561500, 566000, 571000, 580000, 586000, 588000, 920000, 921000, 923000, 926000, 930100, 930200	4,767,094
30	System Benefits Entergy Services, Inc.	107000, 108220, 152000, 163000, 174101, 174104, 174200, 181CPD, 184001, 1840FS, 1840NC, 184EST,	25,140,887
FERC FORM NO. 1 (ED. 12-87)			
Page 450.4			

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.			//	2017/Q4
FOOTNOTE DATA				
			186080, 228100, 253107, 417100, 419000, 426100, 426400, 4265OT, 431000, 524000, 568000, 921000, 923000, 926000, 930200, 931000	
31	System Planning	Entergy Services, Inc.	107000, 152000, 253107, 408110, 426100, 4265OT, 4265TX, 500000, 506000, 507000, 514000, 546000, 549000, 556000, 557000, 561200, 5612BA, 566000, 870000, 920000, 921000, 923000, 926000, 928000, 930200, 935000	5,022,143
32	Tax And Interest Expense	Entergy Services, Inc.	408122, 408123, 408142, 408152, 408155, 408158, 408165, 409112, 409114, 410101, 410120, 411110, 411120, 411430, 419000, 419011, 421000, 426300, 430000, 431000, 431003	15,028,232
33	Transmission	Entergy Services, Inc.	107000, 163000, 174101, 174200, 184001, 1840FS, 1840NC, 184EST, 228100, 253107, 408110, 426100, 4265OT, 4265TX, 431000, 500000, 506000, 517000, 560000, 561100, 561200, 561300, 561500, 561600, 562000, 566000, 567000, 568000, 569000, 573000, 580000, 581000, 582000, 584000, 588000, 589000, 590000, 592000, 593000, 870000, 874000, 880000, 885000, 901000, 903001, 916000, 920000, 921000, 923000, 926000, 928000, 930200, 931000	17,671,238
34	Utility Management and Support Services	Entergy Services, Inc.	107000, 174101, 184001, 184EST, 253107, 408110, 426400, 4265OT, 4265TX, 517000, 520000, 560000, 566000, 568000, 580000, 585000, 588000, 589000, 590000, 870000, 907000, 909000, 910000, 912000, 913000, 916000, 920000, 921000, 923000, 926000, 928000, 930100, 930200, 931000, 935000	20,097,400
35	Utility Support - Distribution	Entergy Services, Inc.	107000, 174101, 174200, 184001, 1840FS, 1840NC, 184EST, 228400, 253107, 408110, 426400, 4265OT, 4265TX, 560000, 568000, 580000, 585000, 588000,	4,565,619
FERC FORM NO. 1 (ED. 12-87)				
Page 450.5				

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.			//	2017/Q4
FOOTNOTE DATA				
			589000, 590000, 596000, 596100, 598000, 870000, 903002, 920000, 921000, 923000, 925000, 926000, 930200, 931000	
36	Utility Support - Operations	Entergy Services, Inc.	107000, 174101, 174200, 184EST, 253107, 408110, 426400, 4265OT, 4265TX, 500000, 560000, 568000, 580000, 581000, 588000, 589000, 590000, 592000, 596000, 596100, 870000, 903001, 911000, 913000, 916000, 920000, 921000, 923000, 926000, 930100, 930200, 931000, 935000	981,616
37	Fossil Support - Ouachita Plant Operations and Support.	Entergy Louisiana, LLC	163000, 408110, 4265OT, 4265TX, 546000, 548000, 549000, 551000, 553000, 926000	3,256,676
38	Inventory Transfers of Materials and Supplies.	Entergy Louisiana, LLC	154PAS, 532000	1,210,370
39	Inventory Transfers of Materials and Supplies.	Entergy Mississippi, Inc.	154PAS	572,260
40	Inventory Transfers of Materials and Supplies.	Entergy Texas, Inc.	154PAS	274,777
41	Non-power Goods or Services Provided to Affiliate from Arkansas			
42	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy New Orleans, LLC	107000	2,394,168
43	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy Louisiana, LLC	107000, 408110, 580000, 587000, 926000	627,634
44	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy Mississippi, Inc.	107000, 580000	253,733

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			

FOOTNOTE DATA

45	Fossil Support - Union Plant Operations and Support.	Entergy Louisiana, LLC	408110, 546000, 553000, 926000	286,546
46	Fossil Support - Union Plant Operations and Support.	Entergy New Orleans, LLC	107000, 408110, 926000	296,512
47	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Louisiana, LLC	107000	460,631
48	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Texas, Inc.	174101, 228100, 42650T, 4265TX	1,176,270
49	Transmission Support - Installation and maintenance of transformers.	Entergy Texas, Inc.	228100, 42650T, 4265TX	255,480

Schedule Page: 429 Line No.: 3 Column: a

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 Operations, Inc.	
Capital Project Excellence	EMPLOEOI, PWRSANWF, SPLEO IPL
Corporate Support - General	EMPLOEOI, PWRSANWF, SPLEO IPL
Distribution	EMPLOEOI, SPLEO IPL
Finance - Risk Management	SPLEO IPL
Nuclear - Regulated	EMPLOEOI, SPLEO IPL, SPLEUNIT
Nuclear Corporate Support	EMPLOEOI, PWRSANWF, SPLEO IPL, SPLEUNIT
Nuclear Operations	EMPLOEOI, SPLEO IPL
Operations and Performance	SPLEO IPL
System Benefits	EMPLOEOI, PWRSANWF, SPLEO IPL
Tax And Interest Expense	SPLEO IPL, SPLEPLXS
Utility Management and Support Services	EMPLOEOI, SPLEO IPL
Entergy Services, Inc.	
Administration	APPSUPAL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLOYAL, GENLEDAL, ITSPENDA, LBRCORPT, LBRFDPOL, LBRFINAN, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVCAL, PKLOADAL, SCPSPALL,
FERC FORM NO. 1 (ED. 12-87)	Page 450.7

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2017/Q4
FOOTNOTE DATA				
	SNUCSITE, SQFTALLC, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP			
Capital Project Excellence	ASSTSALL, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLOYAL, LBRBILAL, LBRCORPT, LBRUTOPN, NETPPEAL, PCNUMALL, PKLOADAL, PWRSNUCA, SCDSPALL, SCFSPALL, SCPSPALL, SNUCSITE, SNUCUNIT, TRANSPND, TRASUBOP, TRSBLNOP			
Chief Administrative Officer	ASSTSALL, EMPLOYAL, ITSPENDA, LBRBILAL, LBRCORPT, SQFTALLC			
Corporate	ASSTSALL, EMPLOYAL, LBRBILAL, LBRCORPT, NETPPEAL, PCNUMALL, SCPSPALL, TRASUBOP			
Corporate - Legal Services	APPSUPAL, ASSTSALL, ASSTSREG, CAPAOPCO, CAPXCOPC, COALARGS, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRFINAN, LBRINFOR, LBRLEGAL, LBRUTOPN, LVLSVCAL, OWNISFI, PCNUMALL, PKLOADAL, PLOSSAL, RECDMGNT, SNUCSITE, SNUCUNIT, SQFTALLC, UNPWROWN			
Corporate - Public Relations	ASSTSALL, ASSTSREG, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLOREG, EMPLOYAL, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRLEGAL, LVLSVCAL, MACCTALL, PCNUMALL, PKLOADAL, SNUCSITE, SQFTALLC, TRSBLNOP			
Corporate Support - General	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, CAPSFUEL, CAPXCOPC, COALARGS, COMCLAIM, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPLUTOP, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, NETPPEAL, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLOSSAL, PRCHKALL, PWRSNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTSPALL, SNSITEAL, SNUCSITE, SNUCUNIT, SNUNITAL, SNUX7877, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, UNPOWSAL, UNPWROWN, VEHCLFOS, VEHCNUC, VEHCUSG			
Customer Service and Operations Support	ASSTSALL, CUSEGAMI, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, EMPLOYAL, PCNUMALL, SNUCUNIT, SQFTALLC			
Customer Service Support	APPSUPAL, ASSTSALL, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, CUSTOEM, EMPLOCSS, EMPLOYAL, EMPLUTOP, LBRBILAL, LBRCORPT, MACCTALL, SQFTALLC, TELPHALL			
Distribution	ASSTSALL, CAPAOPCO, CAPXCOPC, COALARGS, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLOYAL, EMPLTRAN, LBRBILAL, LBRCORPT, LBRUTOPN, PKLOADAL, RADIOALL, SCDSPALL, SQFTALLC, TELPHALL, TRANSPND, TRASUBOP, TRSBLNOP			
Finance - Finance and Accounting	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, COALARGS, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLOREG, EMPLOYAL, EMPLPRES, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, NETPPEAL, OWNISFI, PCNUMALL, PKLOADAL, PRCHKALL, RECDMGNT, SCMATRAN, SCPSPALL, SNSITEAL, SNUCSITE, SNUCUNIT, SNUX7877, SQFTALLC, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, UNPOWSAL, UNPWROWN, VEHCLFOS,			

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.				

FOOTNOTE DATA

	VEHCLNUC, VEHCLUSG
Finance - Information Technology	APPSUPAL, ASSTSALL, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLOYAL, ITSPENDA, LBRBILAL, TRSBLNOP
Fossil Operations	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPACCGT, CAPACENT, CAPAOPCO, CAPSFUEL, CAPSTEAM, CAPXCOPC, COALARGS, COMCLAIM, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, EMPLUTOP, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, NETPPEAL, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, PWRSNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTSPALL, SNSITEAL, SNUCSITE, SNUCUNIT, SNUNITAL, SNUX7877, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, UNPOWSAL, UNPWROWN, VEHCLFOS, VEHCLNUC, VEHCLUSG
Human Resources	ASSTSALL, ASSTSREG, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, LBRBILAL, LBRCORPT, SNUCSITE, SQFTALLC, TRSBLNOP, UNPWROWN
Information Technology	APPSMVSX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ASSTSALL, ASSTSREG, CAPAOPCO, CUSEGAMI, CUSEGRXT, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, EMPLOREG, EMPLOYAL, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRINFOR, LBRLEGAL, LBRSUPCN, NETPPEAL, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCMATRAN, SCMATXNU, SCPSPALL, SCTDSPAL, SNUCSITE, SNUNITAL, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP
Nuclear - Non-Regulated	ARTRNALL, ASSTSALL, CUSEOPCO, EMPLOYAL, LBRCORPT, PKLOADAL, SNUCSITE, SQFTALLC
Nuclear Corporate Support	ASSTSALL, ASSTSREG, CAPAOPCO, CUSTEGOP, EMPLOYAL, EMPLPRES, LBRBILAL, LBRCORPT, LBRSUPCN, LVLSVCAL, PCNUMALL, PWRSNUCA, SNUCSITE, SNUCUNIT, SNUNITAL, TRSBLNOP
Nuclear Operations	PWRSNUCA, SNUCSITE, SNUCUNIT
Operations and Performance	ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTEGOP, EMPLOFOS, EMPLOYAL, EMPLTRAN, ITSPENDA, LBRBILAL, LBRCORPT, LBRLEGAL, LVLSVCAL, PKLOADAL, SNUCSITE, SQFTALLC, TRANSPND, TRSBLNOP
Supply Chain	APTRNALL, ASSTSALL, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, EMPLOYAL, ITSPENDA, LBRCORPT, LBRSUPCN, NETPPEAL, PCNUMALL, PKLOADAL, RECDMGNT, SCDSPALL, SCFSPALL, SCLDTMLS, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SCTSPALL, SNUCSITE, SNUCUNIT, SQFTALLC, TRANSPND, TRSBLNOP
System Benefits	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, CAPSFUEL, CAPXCOPC, COALARGS, COMCLAIM, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, CUSTOEM, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPLUTOP, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, NETPPEAL, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, PWRSNUCA, RADIOALL,

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.				
FOOTNOTE DATA				
	RECDMGNT, SCDSPALL, SCFSPALL, SCMATRAN, SCMATXNU, SCSPALL, SCSPXNC, SCTSPALL, SNSITEAL, SNUCSITE, SNUCUNIT, SNUNITAL, SNUX7877, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, UNPOWSAL, UNPWROWN, VEHCLFOS, VEHCLNUC, VEHCLUSG			
System Planning	ASSTSALL, ASSTSREG, CAPAOPCO, CAPXCOPC, COALARGS, CUSEOPCO, EMPLOYAL, LBRBILAL, LBRUTOPN, PCNUMALL, PKLOADAL, SCFSPALL, SCPSPALL, SNUCSITE, UNPWROWN			
Tax And Interest Expense	LBRBILAL, LVLSVCAL			
Transmission	APPSUPAL, ASSTSALL, CAPAOPCO, CUSEGAMI, CUSEOPCO, CUSTEGOP, CUSTEXTX, EMPLFRAN, EMPLOCSS, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPLUTOP, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRUTOPN, LVLSVCAL, NETPPEAL, PCNUMALL, PKLOADAL, SCDSPALL, SCTSPALL, SQFTALLC, TELPBALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, UNPWROWN, VEHCLNUC, VEHCLUSG			
Utility Management and Support Services	ASSTSALL, ASSTSREG, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOYAL, EMPLUTOP, GENLDREG, LBRBILAL, LBRCORPT, LBRFDPOL, LBRFINAN, LBRLEGAL, LBRUTOPN, LVLSVCAL, MACCTALL, NETPPEAL, PCNUMALL, PKLOADAL, SNUCSITE, SQFTALLC, TELPHALL, TRANSPND, TRSBLNOP			
Utility Support - Distribution	ASSTSALL, COMCLAIM, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOYAL, EMPLTRAN, EMPLUTOP, LBRBILAL, LBRCORPT, LBRFDPOL, LBRUTOPN, LVLSVCAL, PCNUMALL, SQFTALLC, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, VEHCLFOS, VEHCLNUC, VEHCLUSG			
Utility Support - Operations	ASSTSREG, CUSEGAMI, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, EMPLOYAL, LBRUTOPN, MACCTALL, TELPHALL, TRANSPND, TRASUBOP, TRSBLNOP			

Cost Allocator Descriptions

Cost Allocator	Cost Allocator Title	Cost Allocator Description
Entergy Operations, Inc.		
EMPLOEOI	Nuclear South Plant Sites	Based on Nuclear South Site employees
PWRSANWF	Nuclear South Site Employees	Based on the number of Non-System Energy Resources Generation Sites
SPLEOIPL	Nuclear South Units	Based on the number of Nuclear South Plant Sites
SPLEPLXS	Number of Non-System Energy Resources Generation Sites	Based on the number of Pressure Water Reactor Plant Sites
SPLEUNIT	Pressure Water Reactor Sites	Based on the total number of Nuclear South Units
Entergy Services, Inc.		
APPSMVSX	Server and Mainframe Usage - MVS	Based on mainframe usage
APPSUNIX	Server and Mainframe Usage - UNIX	Based on 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

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

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 total assets at period end
ASSTSREG	Total Assets - Regulated Business Units	Based on total assets at period end for all regulated Business Units
BNKACCTA	Bank Accounts	Based on number of bank accounts at period end
CAPACCGT	System Capacity - Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans	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
CAPSFUEL	System Capacity - Entergy Arkansas, Entergy Louisiana, and Entergy Mississippi	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously (SFUEL)
CAPSTEAM	System Capacity - Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy Texas	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously (STEAM)
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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		11	2017/Q4
FOOTNOTE DATA			
		number of gas-only customers provided by Gas Operations. This method should only be used to allocate Advanced Metering Infrastructure	
CUSEGRXT	Electric and Gas Retail Customers - Excluding Entergy Texas	Based on a twelve-month average number of electric and gas retail customers, excluding Entergy Texas	
CUSEGXTX	Electric and Gas Customers - Excluding Entergy Texas	Based on a twelve-month average number of electric and gas residential, commercial, industrial, government, municipal, and general business customers, excluding Entergy Texas	
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 Entergy Texas	Based on a twelve-month average number of electric residential, commercial, industrial, government, and municipal customers for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans	
CUSTOIAM	Electric Customers - Entergy Arkansas and Entergy Mississippi	Based on a twelve-month average number of electric residential, commercial, industrial, government, and municipal customers for Entergy Arkansas and Entergy Mississippi	
EMPLFRAN	Employees - Franchise Operations	Based on the number of full-time and part-time employees within Franchise Operations	
EMPOCSS	Employees - Customer Support Services	Based on the number of full-time and part-time employees within Customer Support Service	
EMPOFOS	Employees - Fossil Plant Operations	Based on the number of full-time and part-time employees within Fossil Plant Operations	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

EMPLOREG	Full-Time and Part-Time Employees - Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, System Energy Resources, and Entergy Services	Based on the number of full-time and part-time employees at period end for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, System Energy Resources, and Entergy Services
	Full-Time and Part-Time Employees - Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, System Energy Resources, and Entergy Services	Based on the number of full-time and part-time employees at period end for Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, System Energy Resources, and Entergy Services
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
GENLDREG	General Ledger Transactions - Regulated Companies	Based on general ledger transactions for regulated companies
GENLEDAL	General Ledger Transactions	Based on general ledger transactions
INSPREAL	Insurance Premiums	Based on non-nuclear insurance premiums
ITSPENDA	Information Technology Total Spending	Based on Information Technology twelve-month total spending
LBRBILAL	Entergy Services Labor Costs Billed	Based on total labor dollars billed to each Client Company by Entergy Services
LBRCOMUN	Entergy Services Labor Billed - Communications	Based on total labor dollars billed to each company by Entergy Services for the Communications function
LBRCORPT	Entergy Services Labor Billed - Corporate	Based on total labor dollars billed to each company by Entergy Services for the Corporate function
LBRFDPOL	Entergy Services Labor Billed - Federal Policy, Regulatory and Governmental Affairs	Based on total labor dollars billed to each company by Entergy Services for the Federal Policy, Regulatory

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2017/Q4
FOOTNOTE DATA				
				and Governmental Affairs function
LBRFINAN	Entergy Services Labor Billed - Finance			Based on total labor dollars billed to each company by Entergy Services for the Finance function
LBRINFOR	Entergy Services Labor Billed - IT			Based on total labor dollars billed to each company by Entergy Services for the IT function
LBRLEGAL	Entergy Services Labor Billed - Legal			Based on total labor dollars billed to each company by Entergy Services for the Legal function
LBRSUPCN	Entergy Services Labor Billed - Supply Chain			Based on total labor dollars billed to each company by Entergy Services for the Supply Chain function
LBRUTOPN	Entergy Services Labor Billed - Utility Operations			Based on total labor dollars billed to each company by Entergy Services for the Utility Operations function
LVLSVCAL	Entergy Services Service Level			Based on Entergy Services total billings to each Client Company
MACCTALL	Managed Accounts			Based on number of retail managed accounts
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 - System Fuels Inc			Based on the percentage ownership of System Fuels Inc
PCNUMALL	Number of PC's			Based on the number of PC's within each Business Unit
PCNUMXNR	Number of PC's - Excluding Non-Regulated Business Units			Based on the number of PC's within each regulated Business Unit at Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, System Energy Resources, and Entergy Services
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.
PLLOSSAL	Property and Liability Paid Losses			Based on a five-year annual average of the property and liability losses paid by the system companies
PRCHKALL	Payroll Checks Issued			Based on the number of
FERC FORM NO. 1 (ED. 12-87)		Page 450.14		

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.			//	2017/Q4
FOOTNOTE DATA				
				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
SCMATXNU	Supply Chain Transactions in Passport - Excluding Nuclear			Based on the number of Supply Chain materials transactions for each Business Unit in Passport, excluding the Nuclear function
SCPSPALL	Supply Chain Total Spending			Based on Supply Chain's Procurement Total Spending
SCPSPXNC	Supply Chain Spending - Excluding Nuclear			Based on Supply Chain Procurement Total Spending, excluding Nuclear for twelve months
SCTDSPAL	Supply Chain Spending - Distribution and Transmission			Based on Supply Chain's Procurement Total Spending for Distribution and Transmission functions
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
SNUX7877	Nuclear Plant Sites - Excluding Entergy FitzPatrick and Entergy Indian Point 3			Based on the number of Nuclear Plant Sites, excluding Entergy FitzPatrick and Entergy Indian Point 3

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

SQFTALLC	Square Footage - All Companies	Based on square footage for all Business Units
TELPBALL	Number of Telephones	Based on the 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)
TRSBLNOP	Transmission Line Miles/Substation	Based on two components: Transmission Line Miles (30% weighting) and the Number of High Voltage Substations (70% weighting)
UNPOWSAL	Unit Power Sales Agreement	Based on allocation factors in connection with Entergy's Unit Power Sales Agreement. This allocates capacity, energy, and related costs from Grand Gulf 1.
UNPWROWN	Ownership - Entergy Arkansas, Entergy Louisiana, and Entergy New Orleans for Union Power	Based on the ownership percentages of Entergy Arkansas, Entergy Louisiana, and Entergy New Orleans for Union Power
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

INDEX

<u>Schedule</u>	<u>Page No.</u>
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
	272-277
Accumulated provisions for depreciation of	
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	i
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
expense	254
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

<u>Schedule</u>	<u>Page No.</u>
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219
	336-337
Directors	105
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	101
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101

<u>Schedule</u>	<u>Page No.</u>
Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337
	401-429

<u>Schedule</u>	<u>Page No.</u>
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation	
amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred	
income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income	
from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Substations	426
Supplies - materials and	227

<u>Schedule</u>	<u>Page No.</u>
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230