THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
The Dayton Power and Light Company	**End of** 2015/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/eforms/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.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

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

“In connection with our regular examination of the financial statements of _____ 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/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.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 1,144 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 150 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 field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent The Dayton Power and Light Company	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1065 Woodman Dr., Dayton, OH 45432	
05 Name of Contact Person Kurt A. Tornquist	06 Title of Contact Person Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 1065 Woodman Dr., Dayton, OH 45432	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(317) 261-8307	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Kurt A. Tornquist	Kurt A. Tornquist	04/18/2016
02 Title Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

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".

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	None
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	None
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	None
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	None
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	None
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	None
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	None
65	Pumped Storage Generating Plant Statistics	408-409	None
66	Generating Plant Statistics Pages	410-411	

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".

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [X] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Kurt A. Tornquist, Controller
The Dayton Power and Light Company
1065 Woodman Drive
Dayton, OH 45432

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.

Ohio - March 23, 1911

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.

Not Applicable

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

Ohio

Electric

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) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficiearies for whom trust was maintained, and purpose of the trust.

The Respondent is a subsidiary of DPL Inc. (a holding company) which holds all of the outstanding common shares of the Respondent. Refer to the DPL Inc. SEC Form 10-K for year ended December 31, 2015, for additional information.

DPL Inc. is an indirect wholly-owned subsidiary of The AES Corporation.

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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President, CEO	Thomas A. Raga	298,320
2	Controller	Kurt A. Tornquist	258,375
3	Vice President of Ohio Generation	Mark Miller	257,500
4	Chief Financial Officer	Craig L. Jackson	542,514
5	Vice President and Treasurer	Jeffrey K. MacKay	352,427
6	General Counsel	Judi L. Sobecki	296,156
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24	Note: Salary for Year includes base salary received in		
25	their capacity of serving all AES US Businesses.		
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), 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	Brian A. Miller (Chairman of Board)	Arlington, Virginia
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3	Elizabeth Hackenson	Arlington, Virginia
4		
5	Kenneth J. Zagzebski	Indianapolis, Indiana
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7	Kazi K. Hasan	Arlington, Virginia
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9	Michael J. Mizell	Indianapolis, Indiana
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11	Paul L. Freedman	Arlington, Virginia
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13	Margaret P. Tigre	Arlington, Virginia
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15	Thomas A. Raga	Dayton, Ohio
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17	Craig L. Jackson (1)	Dayton, Ohio
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19	Tish Mendoza (1)	Arlington, Virginia
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] 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	DP&L does not have any formula rates on file	
2	with FERC.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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
[X] 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	DP&L does not				
2	have any				
3	formula rates				
4	on file with				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1		DP&L does not have any formula rates on file with		
2		FERC.		
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on 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:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None
2. None
3. None
4. None
5. None
6. Please see Note 7 of the Notes to the Financial Statements on Page 123 for details on indebtedness issued during the year.
7. None
8. Employees represented by the utility union, which accounts for approximately 61% of DPL's employees, averaged 2.5% annual wage increase per employee. Such increases were effective November 1, 2014 and the estimated 2015 annual effect to DP&L is $1.7 million. Employees not represented by labor union, which accounts for approximately 39% of DP&L's employees, averaged 3.7% annual increase per employee. Such increases were effective January 1, 2015 and the estimated annual effect to DP&L is $880,000.
9. Please see Note 11 of the Notes to Financial Statements on Page 123 for a discussion of pending and culminated legal proceedings.
10. None
11. None
12. None
13. As of November 2015, the following individuals were elected or reappointed to The Dayton Power and Light Company Board of Directors: Brian A. Miller (Chairman), Elizabeth Hackenson, Michael S. Mizell, Kazi K. Hasan, Paul L. Freedman, Kenneth J. Zagzebski, Thomas A. Raga. As of the same date, the following individuals were appointed to or reappointed as officers: Thomas A. Raga, President and CEO, Craig L. Jackson, Chief Financial Officer, Judi L. Sobecki, General Counsel and Secretary, Jeffrey K. MacKay, Treasurer and Kurt A. Tornquist, Controller.
14. None

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	5,348,662,866	5,115,429,018
3	Construction Work in Progress (107)	200-201	78,020,708	75,370,136
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,426,683,574	5,190,799,154
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,815,125,117	2,614,971,863
6	Net Utility Plant (Enter Total of line 4 less 5)		2,611,558,457	2,575,827,291
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
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)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,611,558,457	2,575,827,291
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,310,819	5,324,162
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
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)		490,000	490,000
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		100,272	100,272
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		4,006,216	3,583,006
31	Long-Term Portion of Derivative Assets – Hedges (176)		2,946,153	343,305
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		12,853,460	9,840,745
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		5,361,401	5,385,771
36	Special Deposits (132-134)		48,196,146	26,947,693
37	Working Fund (135)		7,186	7,186
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		60,066,705	71,668,561
41	Other Accounts Receivable (143)		16,786,252	15,867,321
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		834,792	897,384
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		848,932	17,734,169
45	Fuel Stock (151)	227	70,381,548	63,612,344
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	40,542,974	41,670,542
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	2,352	5,556

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	2,052,045	1,431,448
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)		15,142,130	15,464,282
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		43,281,049	49,036,741
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		11,690,996	9,172,997
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		4,006,216	3,583,006
65	Derivative Instrument Assets - Hedges (176)		19,145,953	5,929,073
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		2,946,153	343,305
67	Total Current and Accrued Assets (Lines 34 through 66)		325,718,508	319,109,989
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		6,916,060	11,836,770
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	185,334,673	201,756,764
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)		2,187,581	1,825,562
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	90,479,962	87,716,728
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)		8,954,079	9,941,158
82	Accumulated Deferred Income Taxes (190)	234	15,853,879	13,058,972
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		309,726,234	326,135,954
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,259,856,659	3,230,913,979

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	411,722	411,722
3	Preferred Stock Issued (204)	250-251	22,850,800	22,850,800
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		303,991,820	303,991,819
7	Other Paid-In Capital (208-211)	253	516,388,433	516,229,697
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	16,716,891	16,716,891
11	Retained Earnings (215, 215.1, 216)	118-119	437,206,363	381,795,167
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
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)	-28,714,877	-42,337,856
16	Total Proprietary Capital (lines 2 through 15)		1,235,417,370	1,166,224,458
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	745,000,000	859,375,000
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	18,103,259	18,234,374
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		183,076	437,548
24	Total Long-Term Debt (lines 18 through 23)		762,920,183	877,171,826
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,977,600	3,232,400
29	Accumulated Provision for Pensions and Benefits (228.3)		95,109,948	105,115,172
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		2,715,506	1,014,645
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		2,741,502	552,896
34	Asset Retirement Obligations (230)		62,130,783	22,881,806
35	Total Other Noncurrent Liabilities (lines 26 through 34)		165,675,339	132,796,919
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		93,546,988	100,116,445
39	Notes Payable to Associated Companies (233)		35,000,000	0
40	Accounts Payable to Associated Companies (234)		509,909	4,712,161
41	Customer Deposits (235)		13,698,810	34,470,392
42	Taxes Accrued (236)	262-263	168,310,598	161,009,477
43	Interest Accrued (237)		4,086,348	9,792,967
44	Dividends Declared (238)		72,232	72,232
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	end of 2015/Q4

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)		0	0
48	Miscellaneous Current and Accrued Liabilities (242)		61,529,760	36,452,155
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		17,704,818	9,675,372
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		2,715,506	1,014,645
52	Derivative Instrument Liabilities - Hedges (245)		9,799,797	2,625,961
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		2,741,502	552,896
54	Total Current and Accrued Liabilities (lines 37 through 53)		398,802,252	357,359,621
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		334,285	1,246,317
57	Accumulated Deferred Investment Tax Credits (255)	266-267	19,979,903	22,372,729
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	66,941	1,866,490
60	Other Regulatory Liabilities (254)	278	29,567,315	9,230,384
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)		611,216,518	623,309,640
64	Accum. Deferred Income Taxes-Other (283)		35,876,553	39,335,595
65	Total Deferred Credits (lines 56 through 64)		697,041,515	697,361,155
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,259,856,659	3,230,913,979

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 columnin 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	1,584,307,159	1,786,398,879		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	992,072,164	1,164,124,878		
5	Maintenance Expenses (402)	320-323	128,300,800	109,497,372		
6	Depreciation Expense (403)	336-337	125,172,199	131,693,994		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,700,797	4,099,610		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,167,779	7,973,101		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	134,854,514	138,481,501		
15	Income Taxes - Federal (409.1)	262-263	55,843,568	34,510,301		
16	- Other (409.1)	262-263	852,827	504,500		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	-19,156,768	7,544,953		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,392,826	-2,505,971		
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)		-13	4		
23	Losses from Disposition of Allowances (411.9)		-9,156	-454		
24	Accretion Expense (411.10)		2,118,199	1,081,101		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,428,524,110	1,597,004,882		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		155,783,049	189,393,997		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
1,584,307,159	1,786,398,879					2
						3
992,072,164	1,164,124,878					4
128,300,800	109,497,372					5
125,172,199	131,693,994					6
2,700,797	4,099,610					7
8,167,779	7,973,101					8
						9
						10
						11
						12
						13
134,854,514	138,481,501					14
55,843,568	34,510,301					15
852,827	504,500					16
-19,156,768	7,544,953					17
						18
-2,392,826	-2,505,971					19
						20
						21
-13	4					22
-9,156	-454					23
2,118,199	1,081,101					24
1,428,524,110	1,597,004,882					25
155,783,049	189,393,997					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		155,783,049	189,393,997		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		60,000	45,000		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		261,653	497,515		
38	Allowance for Other Funds Used During Construction (419.1)		1,609,917	1,152,618		
39	Miscellaneous Nonoperating Income (421)		79,253,819	82,726,773		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		81,185,389	84,421,906		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		75,888	695,609		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,007,451	879,797		
46	Life Insurance (426.2)					
47	Penalties (426.3)		250	51,018		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		507,369	239,700		
49	Other Deductions (426.5)		98,358,624	126,868,445		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		99,949,582	128,734,569		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263				
54	Income Taxes-Other (409.2)	262-263				
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)					
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-18,764,193	-44,312,663		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		20,857,443	25,438,899		
63	Amort. of Debt Disc. and Expense (428)		3,082,103	3,142,072		
64	Amortization of Loss on Reaquired Debt (428.1)		987,079	988,092		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		6,053,239	836,510		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		400,874	345,778		
70	Net Interest Charges (Total of lines 62 thru 69)		30,578,990	30,059,795		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		106,439,866	115,021,539		
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)		106,439,866	115,021,539		

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		381,795,167	426,802,298
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	DP&L Preferred Stock Expense - (Inc.)		-161,890	(161,890)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-161,890	(161,890)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		106,439,866	115,021,539
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	% Series Amount			
25	3.750 A 349,800			
26	3.750 B 260,243			
27	3.900 C 256,737		-866,780	(866,780)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-866,780	(866,780)
30	Dividends Declared-Common Stock (Account 438)			
31			-50,000,000	(159,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-50,000,000	(159,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		437,206,363	381,795,167
	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)		437,206,363	381,795,167
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

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)	106,439,866	115,021,539
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	138,158,974	144,847,806
5	Taxes Applicable to Subsequent Years	-3,713,869	-6,946,945
6	Prepaid Taxes	-1,295,475	-1,059,368
7	Pension and Retiree Benefits	-730,487	19,072,477
8	Deferred Income Taxes (Net)	-19,202,849	7,512,589
9	Investment Tax Credit Adjustment (Net)	-2,392,826	-2,505,971
10	Net (Increase) Decrease in Receivables	11,855,920	-8,536,807
11	Net (Increase) Decrease in Inventory	-9,098,026	-24,624,479
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	69,490	36,790,989
14	Net (Increase) Decrease in Other Regulatory Assets	21,752,515	5,400,031
15	Net Increase (Decrease) in Other Regulatory Liabilities		29,103
16	(Less) Allowance for Other Funds Used During Construction	1,609,917	1,152,618
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Net (Increase) Decrease in Intercompany Receivables/Payable	12,682,985	6,156,164
20	Other (Deferred Debits / Credits)	3,777,757	-38,404,772
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	256,694,058	251,599,738
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-127,011,486	-114,279,762
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):	-758,725	-3,678,489
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-127,770,211	-117,958,251
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	8,802	10,737,445
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	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	Net (Increase) Decrease in Restricted Cash	-279,613	-3,696,757
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):	5,551,716	2,428,225
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-122,489,306	-108,489,338
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	200,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	200,000,000	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-314,506,113	-126,293
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-3,856,229	-669,268
77			
78	Net Decrease in Short-Term Debt (c)	35,000,000	
79			
80	Dividends on Preferred Stock	-866,780	-866,780
81	Dividends on Common Stock	-50,000,000	-159,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-134,229,122	-160,662,341
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-24,370	-17,551,941
87			
88	Cash and Cash Equivalents at Beginning of Period	5,385,771	22,937,712
89			
90	Cash and Cash Equivalents at End of period	5,361,401	5,385,771

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 120 Line No.: 31 Column: b

Purchase of renewable energy credits and emission allowances.

Schedule Page: 120 Line No.: 31 Column: c

See footnote on 120, Line 31, Column b

Schedule Page: 120 Line No.: 53 Column: b

Represents investing activity related to DP&L's Master Trust for $371,053 and proceeds from insurance for $5,180,663.

Schedule Page: 120 Line No.: 53 Column: c

Represents investing activity related to DP&L's Master Trust for $1,502,797 and proceeds from insurance for $925,429.

Schedule Page: 120 Line No.: 76 Column: b

Represents payments of deferred finance costs.

Schedule Page: 120 Line No.: 76 Column: c

See footnote on 120, Line 76, Column b

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 Cormmission 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:	Date of Report	Year/Period of Report
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NOTES TO FINANCIAL STATEMENTS (Continued)

GLOSSARY OF TERMS

The following select terms, abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
AEP Generation	AEP Generation Resources Inc., a subsidiary of American Electric Power Company, Inc. ("AEP"). Columbus Southern Power Company merged into the Ohio Power Company, another subsidiary of AEP, effective December 31, 2011. The Ohio Power generating assets (including jointly-owned units) were transferred into AEP Generation, effective January 1, 2014.
AER	Alternative Energy Rider which allows DP&L to recover costs related to meeting the Ohio renewable portfolio standards.
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AES Ohio Generation	AES Ohio Generation, LLC (formerly DPLE), a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CFTC	Commodity Futures Trading Commission
CAA	U.S. Clean Air Act
CAIR	Clean Air Interstate Rule
Capacity Market	The purpose of the capacity market is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. PJM procures capacity, through a multi-auction structure, on behalf of the load serving entities to satisfy the load obligations. There are four auctions held for each Delivery Year (running from June 1 through May 31). The Base Residual Auction is held three years in advance of the Delivery Year and there is one Incremental Auction held in each of the subsequent three years. DP&L's capacity is located in the "rest of" RTO area of PJM.
CCEM	Customer Conservation and Energy Management
CO2	Carbon Dioxide
ComEd	Commonwealth Edison
CP	In 2015, PJM adopted changes to the capacity market known as "Capacity Performance". The CP program offers the potential for higher capacity revenues, combined with substantially increased penalties for non-performance or under-performance during certain periods identified as "capacity performance hours." The DP&L units will operate under the CP construct starting June 1, 2016.
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CWA	U.S. Clean Water Act
Dark spread	A common metric used to estimate returns over fuel costs of coal-fired electric generating units
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DPL	DPL Inc.

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NOTES TO FINANCIAL STATEMENTS (Continued)

GLOSSARY OF TERMS

The following select terms, abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
DPLE	DPL Energy, LLC, a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales (renamed AES Ohio Generation, LLC effective February 1, 2016)
DPLER	DPL Energy Resources, Inc., formerly a wholly-owned subsidiary of DPL which sold competitive electric energy and other energy services, including sales by a wholly-owned subsidiary, MC Squared, which DPLER sold on April 1, 2015. DPLER was sold by DPL on January 1, 2016. The DPLER sale agreement was signed on December 28, 2015.
DP&L	The Dayton Power and Light Company, the principal subsidiary of DPL and a public utility which sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. DP&L is wholly-owned by DPL.
Duke Energy	Affiliates of Duke Energy with which DP&L co-owns electric generating units and transmission lines in Ohio (Duke Energy Ohio, Inc.)
Dynegy	Dynegy, Inc., the parent of various subsidiaries that, along with AEP Generation and DP&L, co-owns electric generating units in Ohio
EBITDA	Earnings before interest, taxes, depreciation and amortization
EGU	Electric generating unit
ERISA	The Employee Retirement Income Security Act of 1974
ESP	The Electric Security Plan is a cost-based plan that a utility may file with the PUCO to establish SSO rates pursuant to Ohio law
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FASC 805	FASB Accounting Standards Codification 805, “Business Combinations”
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
First and Refunding Mortgage	DP&L’s First and Refunding Mortgage, dated October 1, 1935, as amended, with the Bank of New York Mellon as Trustee
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse gas
IFRS	International Financial Reporting Standards
kV	Kilovolts, 1,000 volts
kWh	Kilowatt hour

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NOTES TO FINANCIAL STATEMENTS (Continued)

GLOSSARY OF TERMS

The following select terms, abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
LIBOR	London Inter-Bank Offering Rate
Master Trust	DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans
MATS	Mercury and Air Toxics Standards
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier formerly wholly-owned by DPLER, sold on April 1, 2015
Merger	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of an Agreement and Plan of Merger dated April 19, 2011 among DPL, AES and Dolphin Sub, Inc. a wholly-owned subsidiary of AES. On the Merger date, DPL became a wholly-owned subsidiary of AES.
Merger date	November 28, 2011, the date of the closing of the merger of DPL and Dolphin Sub, Inc.
MRO	Market Rate Option, a market-based plan that a utility may file with PUCO to establish SSO rates pursuant to Ohio law
MTM	Mark to Market
MVIC	Miami Valley Insurance Company, a wholly-owned insurance subsidiary of DPL that provides insurance services to DPL and its subsidiaries and, in some cases, insurance services to partner companies relative to jointly-owned facilities operated by DP&L
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
Non-bypassable	Charges that are assessed to all customers regardless of whom the customer selects as their retail electric generation supplier
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review is a preconstruction permitting program regulating new or significantly modified sources of air pollution
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority

GLOSSARY OF TERMS

The following select terms, abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
Ohio EPA	Ohio Environmental Protection Agency
OTC	Over the counter
OVEC	Ohio Valley Electric Corporation, an electric generating company in which DP&L holds a 4.9% equity interest
PJM	PJM Interconnection, LLC, an RTO
PPM	Parts per million
PRP	Potentially Responsible Party
Predecessor	DPL prior to the Merger date
PUCO	Public Utilities Commission of Ohio
ROE	Return on equity
RPM	The Reliability Pricing Model was PJM's capacity construct.
RTO	Regional Transmission Organization
SB 221	Ohio Senate Bill 221, is an Ohio electric energy bill that was signed by the Governor on May 1, 2008 and went into effect July 31, 2008. This law required all Ohio distribution utilities to file either an ESP or MRO to be in effect January 1, 2009. The law also contains, among other things, annual targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.
SB 310	Ohio Senate Bill 310, an Ohio electric energy bill that was passed in May 2014 that required all Ohio utilities to show on each bill the approximate cost of complying with renewable energy, energy efficiency and peak demand requirements. It froze the Ohio renewable and energy efficiency annual targets for two year and required a legislative committee to evaluate whether or not the targets should continue.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SEET	Significantly Excessive Earnings Test
Service Company	AES US Services, LLC, the shared services affiliate providing accounting, finance, and other support services to AES' U.S. SBU businesses
SFAS	Statement of Financial Accounting Standards

GLOSSARY OF TERMS

The following select terms, abbreviations or acronyms are used throughout the Notes to Financial Statements:

Abbreviation or Acronym	Definition
SIP	A State Implementation Plan is a plan for complying with the federal CAA, administered by the USEPA. The SIP consists of narrative, rules, technical documentation and agreements that an individual state will use to clean up polluted areas.
SO2	Sulfur Dioxide
SO3	Sulfur Trioxide
SSO	Standard Service Offer represents the retail transmission, distribution and generation services offered by the utility through regulated rates, authorized by the PUCO
SSR	Service Stability Rider
Successor	DPL after the Merger
TCRR	Transmission Cost Recovery Rider
TCRR-B	Transmission Cost Recovery Rider – Bypassable
TCRR-N	Transmission Cost Recovery Rider – Nonbypassable
USEPA	U. S. Environmental Protection Agency
USF	The Universal Service Fund (USF) is a statewide program which provides qualified low-income customers in Ohio with income-based bills and energy efficiency education programs
U.S. SBU	U. S. Strategic Business Unit, AES’ reporting unit covering the businesses in the United States, including DPL

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NOTES TO FINANCIAL STATEMENTS (Continued)

1. Overview and Summary of Significant Accounting Policies

Financial Statement Presentation

The accompanying financial statements are presented in accordance with the requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts (USOA) and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). Certain items in the accompanying Comparative Balance Sheets are classified differently than required by GAAP.

The principle differences from GAAP relate to the presentation of non-legal asset retirement costs, the presentation of mark to market gains and losses on the change in fair value of derivative instruments, the presentation of the current portion of deferred income taxes, the requirement to report deferred tax assets and liabilities separately rather than as a single net amount, and the requirement to include uncertain tax positions in deferred income taxes.

For GAAP purposes, regulatory liabilities include obligations associated with the retirement of tangible long-lived assets and the associated non-legal asset retirement costs. For FERC reporting purposes, the non-legal asset retirement costs are a component of accumulated depreciation. Such costs represent the net non-legal removal costs of plant in service. Accordingly, for FERC financial statement purposes, the Asset Removal Costs are included in accumulated depreciation as opposed to regulatory liabilities as discussed in Note 4 herein.

For GAAP purposes, the mark to market gains and losses on the change in fair value of derivative instruments is included in income and expenses resulting from operations. For FERC reporting purposes, changes in the fair value of derivative instruments not designated as fair value or cash flow hedges are recorded in account 175, derivative instrument assets, or account 244, derivative instrument liabilities, as appropriate, with the gains recorded in account 421, miscellaneous non-operating income, and losses recorded in account 426.5, other deductions. Note 6 herein presents, in accordance with GAAP, the net unrealized gain / (loss) due to changes in fair value of derivative instruments not designated as fair value or cash flow hedges as $(5.6) million and $(3.0) million for the periods ended December 31, 2015 and 2014, respectively. For FERC purposes,$0.8 million and $0.7 million are included in miscellaneous non-operating income and $6.4 million and $3.7 million are included in other deductions for the years ended December 31, 2015 and 2014 respectively.

For GAAP purposes, deferred tax assets and liabilities are reported in a single net amount for those assets and liabilities arising in the same jurisdiction. For FERC reporting purposes, deferred tax assets and liabilities are reported separately rather than as a single net amount. The FERC financial statements include deferred tax assets in account 190 (accumulated deferred income taxes) of $15.9 million and $13.1 million at December 31, 2015 and 2014, respectively. Accumulated deferred tax liabilities of $647.1 million and $662.6 million at December 31, 2015 and 2014, respectively, are included in accounts 281-283 (accumulated deferred income taxes).

For GAAP purposes, uncertain tax positions are to be recorded in accordance with ASC 740 which prescribes a more-likely-than-not recognition threshold and measurements requirements and are not included in the presentation of deferred income taxes. However, in accordance with FERC Docket No. AI07-2-000,deferred income taxes are to be recognized based on the difference between positions taken in tax returns filed or expected to be filed and amounts reported in financial statements. Such tax positions of $3.0 million and $3.0 million as of December 31, 2015 and 2014, respectively, disclosed in Note 8 are included in accounts 281-283 (accumulated deferred income taxes) for FERC purposes.

The Notes to Financial Statements below have been prepared in accordance with GAAP and may appear in The Dayton Power and Light Company Quarterly Report on Form 10-K for the annual period ended December 31, 2015. Accordingly, the disclosures in the Notes to Financial Statements below may not be reflective of the financial statements presented herein, which are presented in conformity with the USOA and published accounting releases.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Estimates and Judgments
The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of Property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Description of Business
DP&L is a public utility incorporated in 1911 under the laws of Ohio. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission services are still regulated. DP&L has the exclusive right to provide such service to its approximately 517,000 customers located in West Central Ohio. Additionally, DP&L procures and provides retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at five coal-fired power stations. Beginning in 2014, DP&L no longer supplied 100% of the generation for SSO customers and starting January 2016, SSO is now 100% competitively bid. Principal industries located in DP&L’s service territory include automotive, food processing, paper, plastic, manufacturing and defense. DP&L's sales reflect the general economic conditions, seasonal weather patterns of the area and the market price of electricity. DP&L sells any excess energy and capacity into the wholesale market. DP&L also sold electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

In accordance with the ESP Order, on December 30, 2013, DP&L filed an application with the PUCO stating its plan to transfer or sell its generation assets. On July 14, 2014, DP&L announced its decision to retain DP&L’s generation assets. On September 17, 2014 the PUCO ordered that DP&L’s application as amended and updated was approved. DP&L is required to sell or transfer its generation assets by January 1, 2017 and continues to look at multiple options to effectuate the separation, including transfer into an unregulated affiliate of DPL or through a sale.

DP&L’s electric transmission and distribution businesses are subject to rate regulation by federal and state regulators, while its generation business is deemed competitive under Ohio law. Accordingly, DP&L applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

DP&L employed 1,189 people at January 31, 2016. Approximately 61% of all employees are under a collective bargaining agreement which expires on October 31, 2017.

Financial Statement

DP&L does not have any subsidiaries. DP&L has undivided ownership interests in five electric generating facilities and numerous transmission facilities. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in DP&L's Financial Statements.

Certain immaterial amounts from prior periods have been reclassified to conform to the current period presentation.

The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of Property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Revenue Recognition

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. Energy sales to customers are based on the reading of their meters that occurs on a systematic basis throughout the month. We recognize the revenues on our statements of operations using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, estimated line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class.

All of the power produced at the generation stations is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. The power sales and purchases within DP&L's service territory are reported on a net hourly basis as revenues or purchased power on our Statements of Operations. We record expenses when purchased electricity is received and when expenses are incurred, with the exception of the ineffective portion of certain power purchase contracts that are derivatives and qualify for hedge accounting. We also have certain derivative contracts that do not qualify for hedge accounting, and their unrealized gains or losses are recorded prior to the receipt of electricity.

Allowance for Uncollectible Accounts

We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collections efforts have been exhausted.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held stations as an asset in property, plant and equipment. New property, plant and equipment additions are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. For non-regulated property, cost also includes capitalized interest. Capitalization of AFUDC and interest ceases at either project completion or at the date specified by regulators. AFUDC and capitalized interest was $2.0 million, $1.5 million, and $1.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization.

Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.

Repairs and Maintenance
Costs associated with maintenance activities, primarily power station outages, are recognized at the time the work is performed. These costs, which include labor, materials and supplies, and outside services required to maintain equipment and facilities, are capitalized or expensed based on defined units of property.

Depreciation
Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For DP&L's generation, transmission and distribution assets, straight-line depreciation is applied monthly on an average composite basis using group rates. For DP&L's generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.6% in 2015, 2.8% in 2014 and 4.4% in 2013. Depreciation was $132.7 million, $141.6 million and $136.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

During the fourth quarter of 2015, DP&L tested the recoverability of long-lived assets at certain generating stations. See Note 13 – Fixed-asset Impairment for more information. Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator.

Regulatory Accounting
As a regulated utility, we apply the provisions of FASC 980 *"Regulated Operations",* which gives recognition to the ratemaking and accounting practices of the PUCO and the FERC. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory assets can also represent performance incentives permitted by the regulator. Regulatory assets have been included as allowable costs for ratemaking purposes, as authorized by the PUCO or established regulatory practices. Regulatory liabilities generally represent obligations to make refunds or future rate reductions to customers for previous over collections or the deferral of revenues collected for costs that DP&L expects to incur in the future.

The deferral of costs (as regulatory assets) is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the PUCO or FERC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings. Our regulatory assets and liabilities have been created pursuant to a specific order of the PUCO or FERC or established regulatory practices, such as other utilities under the jurisdiction of the PUCO or FERC being granted recovery of similar costs. It is probable, but not certain, that these regulatory assets will be recoverable, subject to PUCO or FERC approval. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 3 – Regulatory Assets and Liabilities for more information.

Inventories
Inventories are carried at average cost and include coal, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations.

Intangibles
Intangibles include emission allowances and renewable energy credits. Emission allowances are carried on a first-in, first-out (FIFO) basis for purchased emission allowances. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. Emission allowances are amortized as they are used in our operations on a FIFO basis. Renewable energy credits are carried on a weighted average cost basis and amortized as they are used or retired.

Income Taxes
Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. We establish an allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Our tax positions are evaluated under a more likely than not recognition threshold and measurement analysis before they are recognized for financial statement reporting. Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. Our policy for interest and penalties is to recognize interest and penalties as a component of the provision for income taxes in the Statement of Operations.

Income taxes payable, which are includable in allowable costs for ratemaking purposes in future years, are recorded as regulatory assets with a corresponding deferred tax liability. Investment tax credits that reduced federal income taxes in the years they arose have been deferred and are being amortized to income over the useful lives of the properties in accordance with regulatory treatment. See Note 3 – Regulatory Assets and Liabilities for additional information.

DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. The consolidated tax liability is allocated to each subsidiary based on the separate return method which is specified in our tax allocation agreement and which provides a consistent, systematic and rational approach. See Note 8 – Income Taxes for additional information.

Financial Instruments
We classify our investments in debt and equity financial instruments of publicly traded entities into different categories: held-to-maturity and available-for-sale. Available-for-sale securities are carried at fair value and unrealized gains and losses on those securities, net of deferred income taxes, are presented as a separate component of shareholders' equity. Other-than-temporary declines in value are recognized currently in earnings. Financial instruments classified as held-to-maturity are carried at amortized cost. The cost bases for public equity security and fixed maturity investments are average cost and amortized cost, respectively.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities
DP&L collects certain excise taxes levied by state or local governments from its customers. DP&L's excise taxes and certain other taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Operations. The amounts for the years ended December 31, 2015, 2014 and 2013 were $49.9 million, $50.8 million and $50.5 million, respectively.

Cash and Cash Equivalents
Cash and cash equivalents are stated at cost, which approximates fair value. All highly liquid short-term investments with original maturities of three months or less are considered cash equivalents.

Restricted Cash
Restricted cash includes cash which is restricted as to withdrawal or usage. The nature of the restrictions includes restrictions imposed by agreements related to deposits held as collateral. At December 31, 2015, restricted cash also includes cash received in connection with the January 1, 2016 contract termination canceling DP&L's power sales contracts with DPLER. See Note 14 – Subsequent Event for additional information regarding this contract termination.

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Financial Derivatives
All derivatives are recognized as either assets or liabilities in the balance sheets and are measured at fair value. Changes in the fair value are recorded in earnings unless the derivative is designated as a cash flow hedge of a forecasted transaction or it qualifies for the normal purchases and sales exception.

We use forward contracts to reduce our exposure to changes in energy and commodity prices and as a hedge against the risk of changes in cash flows associated with expected electricity purchases. These purchases are used to hedge our full load requirements. We also hold forward sales contracts that hedge against the risk of changes in cash flows associated with power sales during periods of projected generation facility availability. We use cash flow hedge accounting when the hedge or a portion of the hedge is deemed to be highly effective, which results in changes in fair value being recorded within accumulated other comprehensive income, a component of shareholder's equity. We have elected not to offset net derivative positions in the financial statements. Accordingly, we do not offset such derivative positions against the fair value of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral under master netting agreements. See Note 6 – Derivative Instruments and Hedging Activities for additional information.

Insurance and Claims Costs
In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of DPL, provides insurance coverage solely to us, other DPL subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017, which may or may not be renewed at that time. DP&L is responsible for claim costs below certain coverage thresholds of MVIC and third party insurers for the insurance coverage noted above. DP&L has estimated liabilities for medical, life, and disability reserves for claims costs below certain coverage thresholds of MVIC and third-party providers. We recorded these additional insurance and claims costs of approximately $13.7 million and $15.6 million at December 31, 2015 and 2014, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for workers' compensation, medical, life and disability costs at DP&L are actuarially determined using certain assumptions. There is uncertainty associated with these loss estimates and actual results may differ from the estimates. Modification of these loss estimates based on experience and changed circumstances is reflected in the period in which the estimate is re-evaluated.

Pension and Postretirement Benefits
We recognize, in our Balance Sheets, an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in the funded status recognized in AOCI, except for those portions of our pension and postretirement obligations that can be recovered through future rates. All plan assets are recorded at fair value. We follow the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

We account for and disclose pension and postemployment benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postemployment plans. These GAAP provisions require the use of assumptions, such as the discount rate for liabilities and long-term rate of return on assets, in determining the obligations, annual cost, and funding requirements of the plans.

Effective January 1, 2016, we will apply a disaggregated discount rate approach for determining service cost and interest cost for its defined benefit pension plans and post-retirement plans. This approach is consistent with the requirements of ASC 715 and is considered to be preferential to the aggregated single rate discount approach, which has historically been used in the U.S., because it is more consistent with the philosophy of a full yield curve valuation.

The change in discount rate approach did not have an impact on the measurement of the benefit obligations at December 31, 2015, nor will it impact future remeasurements. This change in approach will impact the service cost and interest cost recorded in 2016 and future years. It will also impact the actuarial gains and losses recorded in future years, as well as the amortization thereof.

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The expected 2016 service costs and interest costs included in Note 9 – Benefit Plans reflect the change in methodology described above. The impact of the change in approach on expected service costs in 2016 is shown below:

$ in millions	Expected 2016 Service Cost			Expected 2016 Interest Cost		
	Disaggregated rate approach	Aggregate rate approach	Impact of change	Disaggregated rate approach	Aggregate rate approach	Impact of change
Total Pension	$ 5.7	$ 6.1	$ (0.4)	$ 14.8	$ 17.9	$ (3.1)
Total Postretirement Benefits	$ 0.2	$ 0.2	$ —	$ 0.6	$ 0.7	$ (0.1)
Total	$ 5.9	$ 6.3	$ (0.4)	$ 15.4	$ 18.6	$ (3.2)

See Note 9 – Benefit Plans for more information.

Related Party Transactions
In the normal course of business, DP&L enters into transactions with other subsidiaries of DPL or AES.

See Note 12 – Related Party Transactions for additional information on Related Party Transactions.

New accounting pronouncements adopted

ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes
Effective December 31, 2015, we prospectively adopted ASU No. 2015-17, which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. As a result, each jurisdiction will now only have one net noncurrent deferred tax asset or liability. The guidance does not change the existing requirement that only permits offsetting within a jurisdiction; that is, companies will remain prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. Additionally, the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the update. As we elected to apply this ASU prospectively, prior periods were not adjusted.

ASU No. 2015-13, Derivatives and Hedging (Topic 815):Derivatives and Hedging: Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Market
In August 2015, the FASB issued ASU No. 2015-13, which resolves the diversity in practice resulting from determining whether certain contracts qualify for the normal purchases and normal sales scope exception under ASC Topic 815, Derivatives and Hedging. This standard clarifies that entities would not be precluded from applying the normal purchases and normal sales exception to certain forward contracts that necessitate the transmission of electricity through, or delivery to a location within, a nodal energy market. The standard is effective upon issuance and should be applied prospectively. As we had designated qualifying contracts as normal purchase or normal sales, there was no impact on our financial statements upon adoption of this standard.

Accounting pronouncements issued but not yet effective

ASU No. 2016-01, Financial Instruments — Overall (Topic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, which was designed to improve the recognition and measurement of financial instruments through targeted changes to existing GAAP. The guidance requires equity investments (except those that are accounted for under the equity method of accounting or result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income; that entities use the exit price notion when measuring financial instrument fair values; that an entity separate presentation of financial assets and liabilities by measurement category and form of financial asset on the Balance Sheets or Notes to the financial statements; that an

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entity present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk (or "own credit") when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. Also, the standard eliminates the requirement for public entities to disclose the methods and significant assumptions used to estimate the fair value required to be disclosed for financial instruments measured at amortized cost on the Balance Sheets. The standard is effective beginning with interim periods starting after December 31, 2017 and cannot be applied early. We are currently evaluating the applicability and materiality of the standard, but we do not anticipate a material impact on our financial statements.

ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments
In September 2015, the FASB issued ASU 2015-16, which simplifies the measurement-period adjustments in business combinations. It eliminates the requirement that an acquirer in a business combination account for measurement-period adjustments retrospectively. An acquirer will recognize a measurement-period adjustment during the period in which it determines the amount of the adjustment. The standard is effective for public entities for annual reporting periods beginning after December 15, 2015, and interim periods therein. Early adoption is permitted for financial statements that have not been issued. The new guidance should be applied prospectively to adjustments to provisional amounts that occur after the effective date of this standard. We will adopt this standard on January 1, 2016, which is not expected to have a material impact on our financial statements.

ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30)
In April 2015, the FASB issued ASU No. 2015-03, which simplifies the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein, and requires the use of the full retrospective approach. Early adoption is permitted for financial statements that have not been previously issued. As of December 31, 2015 DP&L had approximately $6.3 million in deferred financing costs classified in other current and other non-current assets that would be reclassified to reduce the related debt liabilities upon adoption of ASU No. 2015-03.

ASU No. 2015-15, Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements
In August 2015, the FASB issued ASU No. 2015-15, which clarifies that the SEC Staff would not object to an entity presenting debt issuance costs related to line-of-credit arrangements as an asset that is subsequently amortized ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. This standard should be adopted concurrent with adoption of ASU 2015-03 (which is described above). As of December 31, 2015, we had deferred financing costs related to lines of credit of approximately $0.7 million recorded within Other noncurrent assets that would not be reclassified upon adoption of this standard.

ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU No. 2015-11, which simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with a lower of cost or net realizable value test. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted. The new guidance must be applied prospectively. As we already used the net realizable value to make lower of cost or market determinations, there will be no impact on our financial statements upon adoption of this standard.

ASU No. 2015-05, Intangibles – Goodwill and Other: Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement
In April 2015, the FASB issued ASU No. 2015-05, which clarifies how customers in cloud computing arrangements should determine whether the arrangement includes a software license and eliminates the existing requirement for customers to account for software licenses they acquired by analogizing to the accounting guidance on leases. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. The standard permits the use of a prospective or retrospective approach. As all of our cloud computing arrangements will continue to be accounted for as service agreements, there will be no impact on our financial statements upon the adoption of this standard.

ASU No. 2014-05, Presentation of Financial Statements: Going Concern

The FASB recently issued ASU 2014-15 “Presentation of Financial Statements - Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern)” effective for annual and interim periods ending after December 15, 2016. ASU 2014-15 requires management to evaluate whether there are conditions or events, considered in aggregate, that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the financial statements are issued. There are required disclosures if substantial doubt is identified including documentation of: principal conditions or events that raised substantial doubt about the entity’s ability to continue as a going concern (before consideration of management’s plans), management’s evaluation of the significance of those conditions or events in relation to the entity’s ability to meet its obligations, and management’s plans that alleviated substantial doubt about the entity’s ability to continue as a going concern. This ASU is not expected to have any impact on our overall results of operations, financial position or cash flows.

ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606)

In May 2014, the FASB issued ASU No. 2014-09, which clarifies principles for recognizing revenue and will result in a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The objective of the new standard is to provide a single and comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The standard requires an entity to recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contract with Customers (Topic 606): Deferral of the Effective Date, which deferred the effective date of ASU 2014-09 by one year, resulting in the new revenue standard being effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. Early adoption is now permitted only as of the original effective date for public entities (that is, no earlier than 2017 for calendar year-end entities). The standard permits the use of either a full retrospective or modified retrospective approach. We have not yet selected a transition method and are currently evaluating the impact of adopting the standard on our financial statements.

ASU No. 2015-02, Consolidation – Amendments to the Consolidation Analysis (Topic 810)

In February 2015, the FASB issued ASU 2015-02, which makes targeted amendments to the current consolidation guidance and ends the deferral granted to investment companies from applying the Variable Interest Entity (VIE) guidance. The standard amends the evaluation of whether (1) fees paid to a decision-maker or service providers represent a variable interest, (2) a limited partnership or similar entity has the characteristics of a VIE and (3) a reporting entity is the primary beneficiary of a VIE. The standard is effective for annual periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. We do not expect this standard to have an impact on our financial statements upon adoption.

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2. Supplemental Financial Information

$ in millions	December 31, 2015	December 31, 2014
Accounts receivable, net		
Unbilled revenue	**$ 43.3**	$ 49.0
Customer receivables	**54.1**	68.7
Amounts due from partners in jointly-owned stations	**16.0**	15.2
Other	**6.9**	20.7
Provisions for uncollectible accounts	**(0.8)**	(0.9)
Total accounts receivable, net	**$ 119.5**	$ 152.7
Inventories		
Fuel and limestone	**$ 72.2**	$ 65.3
Plant materials and supplies	**33.7**	32.3
Other	**2.1**	1.4
Total inventories, at average cost	**$ 108.0**	$ 99.0

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Accumulated Other Comprehensive Income (Loss)
The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2015, 2014 and 2013 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components	**Affected line item in the Statements of Operations**	**Years ended December 31,**		
$ in millions		**2015**	2014	2013
Gains and losses on Available-for-sale securities activity (Note 5):				
	Other income / (deductions)	**$ —**	$ 0.4	$ 2.1
	Tax expense	**—**	(0.2)	(0.7)
	Net of income taxes	**—**	0.2	1.4
Gains and losses on cash flow hedges (Note 6):				
	Interest expense	**(1.1)**	(1.1)	(2.1)
	Revenue	**(18.7)**	28.4	2.2
	Purchased power	**4.4**	(0.4)	5.0
	Total before income taxes	**(15.4)**	26.9	5.1
	Tax expense	**5.6**	(11.5)	(2.5)
	Net of income taxes	**(9.8)**	15.4	2.6
Amortization of defined benefit pension items (Note 9):				
	Reclassification to Other income / (deductions)	**5.6**	4.1	5.7
	Tax benefit	**(1.9)**	(1.4)	(1.9)
	Net of income taxes	**3.7**	2.7	3.8
Total reclassifications for the period, net of income taxes		**$ (6.1)**	$ 18.3	$ 7.8

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The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2015 and 2014 are as follows:

$ in millions	Gains / (losses) on available-for-sale securities	Gains / (losses) on cash flow hedges	Change in unfunded pension obligation	Total
Balance at December 31, 2013	$ 0.8	$ 6.2	$ (33.7)	$ (26.7)
Other comprehensive loss before reclassifications	(0.3)	(18.8)	(14.8)	(33.9)
Amounts reclassified from accumulated other comprehensive income	0.2	15.4	2.7	18.3
Net current period other comprehensive loss	(0.1)	(3.4)	(12.1)	(15.6)
Balance at December 31, 2014	0.7	2.8	(45.8)	(42.3)
Other comprehensive income / (loss) before reclassifications	**(0.2)**	**18.2**	**1.7**	**19.7**
Amounts reclassified from accumulated other comprehensive income / (loss)	**—**	**(9.8)**	**3.7**	**(6.1)**
Net current period other comprehensive income / (loss)	**(0.2)**	**8.4**	**5.4**	**13.6**
Balance at December 31, 2015	**$ 0.5**	**$ 11.2**	**$ (40.4)**	**$ (28.7)**

3. Regulatory Assets and Liabilities

In accordance with FASC 980, we have recognized total regulatory assets of $194.3 million and $211.7 million at December 31, 2015 and 2014, respectively, and total regulatory liabilities of $151.4 million and $128.5 million at December 31, 2015 and 2014, respectively. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 – Overview and Summary of Significant Accounting Policies for accounting policies regarding Regulatory Assets and Liabilities.

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The following table presents DP&L's Regulatory assets and liabilities:

$ in millions	Type of Recovery	Amortization Through	December 31, 2015	December 31, 2014
Regulatory assets, current:				
Fuel and purchased power recovery costs	A	2016	**$ 13.9**	$ 16.3
Economic development costs	A	2016	**0.5**	2.1
Deferred storm costs	B	2015	**—**	22.3
Energy efficiency program	A	2016	**—**	1.8
Other miscellaneous	A	2016	**—**	1.7
Total regulatory assets, current			**$ 14.4**	$ 44.2
Regulatory assets, non-current:				
Pension benefits	B	Ongoing	**$ 91.6**	$ 99.6
Deferred recoverable income taxes	B/C	Ongoing	**36.4**	43.1
Fuel costs	B	Undetermined	**12.7**	—
Unrecovered OVEC charges	D	Undetermined	**10.5**	—
Unamortized loss on reacquired debt	B	Various	**9.0**	9.9
Smart grid and advanced metering infrastructure costs	D	Undetermined	**7.3**	6.6
Generation separation costs		Undetermined	**3.9**	1.6
Retail settlement system costs	D	Undetermined	**3.1**	3.1
Consumer education campaign	D	Undetermined	**3.0**	3.0
Rate case costs	D	Undetermined	**1.9**	—
Other miscellaneous	D	Undetermined	**0.5**	0.6
Total regulatory assets, non-current			**$ 179.9**	$ 167.5
Total regulatory assets			$ 194.3	$ 211.7
Regulatory liabilities, current:				
Energy efficiency program			**$ 9.2**	$ —
Competitive bidding			**9.1**	—
Transmission costs			**3.7**	2.9
Reconciliation rider			**2.1**	—
Other miscellaneous			**0.3**	1.5
Total regulatory liabilities, current			**$ 24.4**	$ 4.4
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			**$ 121.8**	$ 119.3
Postretirement benefits			**5.2**	4.8
Total regulatory liabilities, non-current			**$ 127.0**	$ 124.1
Total regulatory liabilities			**$ 151.4**	$ 128.5

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A – Recovery of incurred costs without a rate of return.
B – Recovery of incurred costs plus rate of return.
C – Balance has an offsetting liability resulting in no effect on rate base.
D – Recovery not yet determined, but is probable of occurring in future rate proceedings.

Regulatory assets

Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. As part of the PUCO approval process, an outside auditor reviews fuel costs and the fuel procurement process. The audit for 2014 is in process. The costs recovered through the fuel rider have decreased significantly over the past three years as more SSO supply is provided through the competitive bid. While no further fuel or purchased power costs will be recoverable through the rider, it will continue for up to six months to allow for recovery of the ending deferral amount.

Fuel costs - long-term represent unrecovered fuel costs related to DP&L’s fuel rider from 2010 through 2015 resulting from a declining SSO customer base. DP&L has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Economic development costs represent costs incurred to promote economic development within the State of Ohio. These costs are being recovered through an Economic Development Rider that is subject to a bi-annual true-up process for any over/under recovery of costs.

Deferred storm costs represent costs incurred to repair the damage to DP&L’s distribution equipment by major storms in 2008, 2011 and 2012. All such costs have now been recovered.

Energy efficiency program costs represent costs incurred to develop and implement various customer programs addressing energy efficiency. These costs are being recovered through an Energy Efficiency Rider (EER) that began July 1, 2009 and that is subject to an annual true-up for any over/under recovery of costs. In addition to recovery of program costs, this rider has allowed for DP&L to recover lost margin associated with decreases in sales as a result of the programs implemented. The authority to recover lost margin included a maximum amount, which DP&L reached in the fourth quarter of 2015. Consequently, we discontinued accruing an asset for lost revenues after the maximum was reached. In addition, this rider provides that DP&L can earn a “shared savings” incentive that is tiered depending upon the level of success the programs reach. In 2014 and 2015, the maximum shared savings was accrued based upon performance, which is equal to $4.5 million per year, after income taxes.

Pension benefits represent the qualifying FASC 715 “Compensation - Retirement Benefits” costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow-through items as the result of tax benefits previously provided to customers. This is the cumulative flow-through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes will decrease over time.

Unrecovered OVEC charges represent the portion of capacity charges from OVEC that were not recoverable through DP&L’s fuel rider beginning in October 2014. DP&L expects to recover these costs through a future rate proceeding.

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Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods that have been deferred. These deferred losses are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

Smart Grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and the implementation of AMI. On October 19, 2010, DP&L elected to withdraw its case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects DP&L to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that DP&L will, when appropriate, file new Smart Grid and/or AMI business cases in the future. This plan is currently under development and we plan to seek recover of these deferred costs in a regulatory rate proceeding in the near future. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Generation separation costs represent financing, redemption and other costs related to the divestiture of DP&L's generation assets. The PUCO directed DP&L to divest its generation assets by January 1, 2017. DP&L requested and was granted permission by the PUCO to defer all financing, redemption and related costs it incurs to transfer its generation assets. DP&L has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Retail settlement system costs represent costs to implement a retail settlement system that reconciles the energy a CRES supplier delivers to its customers with what its customers actually use. DP&L has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. DP&L has requested recovery of these costs as part of its pending distribution rate case filing.

Rate case costs represent costs associated with preparing a distribution rate case. DP&L has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Regulatory liabilities

Energy efficiency program costs see "*Regulatory Assets - Energy efficiency program costs*" above.

Competitive bidding represents costs associated with the development and implementation of a Competitive Bidding Process, establishing contracts to supply power for a portion of DP&L's Standard Service Offer load, as well as the net over/under recovery of the cost of the power purchased from the bid winners.

Transmission costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. On an annual basis, retail rates are adjusted to true-up costs with recovery in rates.

Reconciliation rider represents the costs that exceed 10 percent of the base amount of the following riders: Fuel, RPM, Alternative Energy and Competitive Bidding. This rider is in an overcollection position and will be discontinued after this overcollection has been refunded to customers.

Estimated costs of removal – regulated property reflect an estimate of amounts collected in customer rates for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

Postretirement benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

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4. Property, Plant and Equipment

The following is a summary of DP&L's Property, plant and equipment with corresponding composite depreciation rates at December 31, 2015 and 2014:

	December 31,			
$ in millions	**2015**	**Composite Rate**	2014	Composite Rate
Regulated:				
Transmission	**$ 413.7**	**2.3%**	$ 402.4	2.3%
Distribution	**1,639.7**	**3.3%**	1,568.0	3.5%
General	**96.9**	**8.4%**	116.1	6.7%
Non-depreciable	**62.5**	**N/A**	61.6	N/A
Total regulated	**2,212.8**		2,148.1	
Unregulated:				
Production / Generation	**3,016.8**	**2.1%**	2,957.7	2.4%
Non-depreciable	**15.1**	**N/A**	14.9	N/A
Total unregulated	**3,031.9**		2,972.6	
Total property, plant and equipment in service	**$ 5,244.7**	**2.6%**	$ 5,120.7	2.8%

DP&L and certain other Ohio utilities have undivided ownership interests in five coal-fired electric generating facilities and numerous transmission facilities. Certain expenses, primarily fuel costs for the generating units, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. At December 31, 2015, DP&L had $39.0 million of construction work in process at such facilities. DP&L's share of the operations of such facilities is included within the corresponding line in the Statements of Operations and DP&L's share of the investment in the facilities is included within Total net property, plant and equipment in the Balance Sheets. Each joint owner provides their own financing for their share of the operations and capital expenditures of the jointly-owned station.

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Coal-fired facilities
DP&L's undivided ownership interest in such facilities at December 31, 2015, is as follows:

	DP&L Share		**DP&L** Carrying Value		
	Ownership %	Summer Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)
Jointly-owned production units					
Conesville - Unit 4	16.5	129	$ 27	$ 8	$ 1
Killen - Unit 2	67.0	402	655	326	2
Miami Fort - Units 7 and 8	36.0	368	366	171	6
Stuart - Units 1 through 4	35.0	808	772	338	18
Zimmer - Unit 1	28.1	371	1,104	690	12
Transmission (at varying percentages)			99	64	—
Total		2,078	$ 3,023	$ 1,597	$ 39

Each of the above generating units has SCR and FGD equipment installed.

Beckjord Unit 6 was retired effective October 1, 2014 and DP&L sold its interest in East Bend on December 30, 2014.

As part of the provisional DPL purchase accounting adjustments related to the Merger, four stations (Beckjord, Conesville, East Bend and Hutchings) had future expected cash flows that, when discounted, produced a fair market value different than DP&L's carrying value. Since DP&L did not apply push down accounting, this valuation did not affect the carrying value of these stations' valuation at DP&L. In the fourth quarter of 2013, DP&L performed an impairment review of its stations and recorded impairment expense of $86.0 million related to two of its stations, Conesville and East Bend. See Note 13 – Fixed-asset Impairment for more information on these impairments.

AROs
We recognize AROs in accordance with GAAP which requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time those obligations are incurred. Upon initial recognition of a legal liability, costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the related asset. Our legal obligations are associated with the retirement of our long-lived assets, consisting primarily of river intake and discharge structures, coal unloading facilities, loading docks, ice breakers and ash disposal facilities. Our generation AROs are recorded within Other deferred credits on the consolidated balance sheets.

Estimating the amount and timing of future expenditures of this type requires significant judgment. Management routinely updates these estimates as additional information becomes available.

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Changes in the Liability for Generation AROs

$ in millions		
Balance at December 31, 2013	$	19.9
Calendar 2014		
Additions		3.6
Accretion expense		1.1
Settlements		(1.7)
Balance at December 31, 2014		22.9
Calendar 2015		
Additions		40.3
Accretion expense		2.1
Settlements		(3.2)
Balance at December 31, 2015	$	62.1

Asset Removal Costs
We continue to record cost of removal for our regulated transmission and distribution assets through our depreciation rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $121.8 million and $119.3 million in estimated costs of removal at December 31, 2015 and 2014, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 – Regulatory Assets and Liabilities for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Balance at December 31, 2013	$	115.0
Calendar 2014		
Additions		19.6
Settlements		(15.3)
Balance at December 31, 2014		119.3
Calendar 2015		
Additions		24.3
Settlements		(21.8)
Balance at December 31, 2015	$	121.8

5. Fair Value

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other method is available to us. The fair value of our financial instruments represents estimates of possible value that may or may not be realized in the future.

The table below presents the fair value and cost of our non-derivative instruments at December 31, 2015 and 2014. See also Note 6 – Derivative Instruments and Hedging Activities for the fair values of our derivative instruments.

	December 31, 2015		December 31, 2014	
$ in millions	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Assets				
Money market funds	**$ 0.2**	**$ 0.2**	$ 0.1	$ 0.1
Equity securities	**3.0**	**3.8**	2.7	3.7
Debt securities	**4.4**	**4.3**	4.7	4.7
Hedge Funds	**0.4**	**0.4**	0.8	0.8
Real Estate	**0.3**	**0.3**	0.4	0.4
Total assets	**$ 8.3**	**$ 9.0**	$ 8.7	$ 9.7
Liabilities				
Debt	**$ 762.9**	**$ 764.2**	$ 877.1	$ 882.5

Fair value hierarchy
Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as:

- Level 1 (quoted prices in active markets for identical assets or liabilities);
- Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active); and
- Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using global average default rates based on an annual study conducted by a large rating agency.

We did not have any transfers of the fair values of our financial instruments between Level 1 and Level 2 of the fair value hierarchy during the twelve months ended December 31, 2015 and 2014.

Debt
The fair value of debt is based on current public market prices for disclosure purposes only. Unrealized gains or losses are not recognized in the financial statements as debt is presented at the carrying value, net of unamortized premium or discount, in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2016 to 2061.

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Master trust assets
DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans. These assets are primarily comprised of open-ended mutual funds, which are valued using the net asset value per unit. These investments are recorded at fair value within Other deferred assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DP&L had $0.8 million ($0.5 million after tax) in unrealized gains and $0.1 million ($0.1 million after tax) in unrealized losses on the Master Trust assets in AOCI at December 31, 2015 and $1.1 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2014.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, an immaterial amount of unrealized gains were reversed into earnings. Over the next twelve months, an immaterial amount of unrealized gains is expected to be reversed to earnings.

The fair value of assets and liabilities at December 31, 2015 and the respective category within the fair value hierarchy for DP&L was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2015 (a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.2	$ 0.2	$ —	$ —
Equity securities	3.8	—	3.8	—
Debt securities	4.3	—	4.3	—
Hedge Funds	0.4	—	0.4	—
Real Estate	0.3	—	0.3	—
Total Master trust assets	9.0	0.2	8.8	—
Derivative assets				
FTRs	0.2	—	—	0.2
Forward power contracts	30.6	—	30.6	—
Total derivative assets	30.8	—	30.6	0.2
Total assets	$ 39.8	$ 0.2	$ 39.4	$ 0.2
Liabilities				
FTRs	$ 0.5	$ —	$ —	$ 0.5
Forward power contracts	27.0	—	23.9	3.1
Total derivative liabilities	27.5	—	23.9	3.6
Long-term debt	764.2	—	746.1	18.1
Total liabilities	$ 791.7	$ —	$ 770.0	$ 21.7

(a) Includes credit valuation adjustment.

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The fair value of assets and liabilities at December 31, 2014 and the respective category within the fair value hierarchy for DP&L was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2014 (a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.1	$ 0.1	$ —	$ —
Equity securities	3.7	3.7	—	—
Debt securities	4.7	4.7	—	—
Hedge Funds	0.8	—	0.8	—
Real Estate	0.4	0.4	—	—
Total Master trust assets	9.7	8.9	0.8	—
Derivative assets				
Forward power contracts	15.1	—	13.9	1.2
Total derivative assets	15.1	—	13.9	1.2
Total assets	$ 24.8	$ 8.9	$ 14.7	$ 1.2
Liabilities				
Forward power contracts	$ 11.2	$ —	$ 11.2	$ —
FTRS	0.6	—	—	0.6
Heating Oil Futures	0.4	0.4	—	—
Natural Gas Futures	0.1	0.1	—	—
Total derivative liabilities	12.3	0.5	11.2	0.6
Long-term debt	882.5	—	864.3	18.2
Total liabilities	$ 894.8	$ 0.5	$ 875.5	$ 18.8

(a) Includes credit valuation adjustment.

Our financial instruments are valued using the market approach in the following categories:

- Level 1 inputs are used for derivative contracts, such as heating oil futures, and for money market accounts that are considered cash equivalents. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions.

- Level 2 inputs are used to value derivatives such as forward power contracts (which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market). Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit.

- Level 3 inputs, such as financial transmission rights, are considered a Level 3 input because the monthly auctions are considered inactive. Our Level 3 inputs are immaterial to our derivative balances as a whole and as such no further disclosures are presented.

Our debt is fair valued for disclosure purposes only and most of the fair values are determined using quoted market prices in inactive markets. These fair value inputs are considered Level 2 in the fair value hierarchy. The WPAFB note is not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

Approximately 99% of the inputs to the fair value of our derivative instruments are from quoted market prices.

Non-recurring Fair Value Measurements

We use the cost approach to determine the fair value of our AROs, which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. AROs for asbestos, ash ponds, underground storage tanks, and river structures increased by a net amount of $39.2 million ($25.5 million after tax) and $3.0 million ($2.0 million after tax) during the 12 months ended December 31, 2015 and 2014, respectively. The majority of the increase for 2015 is due to a net increase in the ARO for ash ponds of $40.3 million ($26.2 million after tax) as a result of new rules promulgated by the USEPA that were published in the Federal Register in April 2015 and became effective in October 2015. See Note 4 – Property, Plant and Equipment for more information about AROs.

When evaluating impairment of long-lived assets, we measure fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to the carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

$ in millions	Year ended December 31, 2013				
	Carrying	Fair Value			Gross
	Amount	Level 1	Level 2	Level 3	Loss
Assets					
Long-lived assets held and used (a)					
Conesville	$ 30.0	$ —	$ —	$ 20.0	$ 10.0
East Bend	$ 76.0	$ —	$ —	$ —	$ 76.0

(a) See Note 13 – Fixed-asset Impairment for further information.

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The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets during the year ended December 31, 2013:

$ in millions	Fair Value	Valuation Technique	Unobservable input	Range (Weighted Average)
Long-lived assets held and used:				
DP&L (Conesville)	$ —	Discounted cash flows	Annual revenue growth	-31% to 18% (0)

6. Derivative Instruments and Hedging Activities

In the normal course of business, DP&L enters into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing, when possible, to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as cash flow hedges if they qualify under FASC 815 for accounting purposes.

At December 31, 2015, DP&L had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	**Not designated**	**MWh**	**10.2**	**—**	**10.2**
Forward Power Contracts	**Designated**	**MWh**	**1,676.7**	**(7,795.8)**	**(6,119.1)**
Forward Power Contracts	**Not designated**	**MWh**	**5,049.9**	**(1,665.7)**	**3,384.2**

At December 31, 2014, DP&L had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Not designated	MWh	10.5	—	10.5
Heating Oil Futures	Not designated	Gallons	378.0	—	378.0
Natural Gas	Not designated	Dths	200.0		200.0
Forward Power Contracts	Designated	MWh	175.0	(2,991.0)	(2,816.0)
Forward Power Contracts	Not designated	MWh	1,725.2	(2,804.0)	(1,078.8)

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Cash flow hedges
As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The fair values of cash flow hedges determined by current public market prices will continue to fluctuate with changes in market prices up to contract expiration. The effective portion of the hedging transaction is recognized in AOCI and transferred to earnings using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

The following tables set forth the gains / (losses) recognized in AOCI and earnings related to the effective portion of derivative instruments and the gains / (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the periods indicated:

	Years ended December 31,					
	2015	**2015**	2014	2014	2013	2013
$ in millions (net of tax)	**Power**	**Interest Rate Hedge**	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	**$ 0.2**	**$ 2.6**	$ 1.0	$ 5.2	$ (4.7)	$ 7.3
Net gains / (losses) associated with current period hedging transactions	**18.2**	**—**	(18.8)	—	1.0	—
Net gains / (losses) reclassified to earnings:						
Interest Expense	**—**	**(0.6)**	—	(2.6)	—	(2.1)
Revenues	**(12.0)**	**—**	18.2	—	1.4	—
Purchased Power	**2.8**	**—**	(0.2)	—	3.3	—
Ending accumulated derivative gain in AOCI	**$ 9.2**	**$ 2.0**	$ 0.2	$ 2.6	$ 1.0	$ 5.2

Net gains or losses associated with the ineffective portion of the hedging transactions were immaterial in the periods presented.

Portion expected to be reclassified to earnings in the next twelve months (a)	**$ 5.9**	**$ (0.6)**
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**36**	**—**

(a) The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

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Derivatives not designated as hedges
Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchases and sales exceptions under FASC 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the consolidated statements of results of operations in the period in which the change occurred. This is commonly referred to as “MTM accounting”. Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We mark to market FTRs, heating oil futures and certain forward power contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided under GAAP. Derivative contracts that have been designated as normal purchases or normal sales under GAAP are not subject to MTM accounting treatment and are recognized in the consolidated statements of results of operations on an accrual basis.

Regulatory assets and liabilities
In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of DP&L’s load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers’ portion of the heating oil futures are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following tables show the amount and classification within the statements of results of operations or balance sheets of the gains and losses on DP&L’s derivatives not designated as hedging instruments for the years ended December 31, 2015, 2014 and 2013.

	Year ended December 31, 2015				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	**$ 0.4**	**$ 0.3**	**$ (6.3)**	**$ 0.1**	**$ (5.5)**
Realized gain / (loss)	**(0.3)**	**(0.2)**	**(9.9)**	**(0.1)**	**(10.5)**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**
Recorded on Balance Sheet:					
Regulatory asset	**$ 0.1**	**$ —**	**$ —**	**$ —**	**$ 0.1**
Recorded in Income Statement: gain / (loss)					
Revenue	**—**	**—**	**27.4**	**—**	**27.4**
Purchased Power	**—**	**0.1**	**(43.6)**	**—**	**(43.5)**
Fuel	**—**	**—**	**—**	**—**	**—**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**

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	Year ended December 31, 2014				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ (0.6)	$ (0.8)	$ (1.5)	$ (0.1)	$ (3.0)
Realized gain / (loss)	(0.1)	0.7	(3.0)	(0.1)	(2.5)
Total	$ (0.7)	$ (0.1)	$ (4.5)	$ (0.2)	$ (5.5)
Recorded on Balance Sheet:					
Regulatory asset	$ (0.1)	$ —	$ —	$ —	$ (0.1)
Recorded in Income Statement: gain / (loss)					
Revenue	$ —	$ —	$ 0.7	$ —	$ 0.7
Purchased Power	—	(0.1)	(5.2)	(0.2)	(5.5)
Fuel	(0.6)	—	—	—	(0.6)
Total	$ (0.7)	$ (0.1)	$ (4.5)	$ (0.2)	$ (5.5)

	Year ended December 31, 2013				
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ —	$ —	$ 0.3	$ (1.2)	$ (0.9)
Realized gain / (loss)	—	0.1	1.2	1.6	2.9
Total	$ —	$ 0.1	$ 1.5	$ 0.4	$ 2.0
Recorded on Balance Sheet:					
Partners' share of gain	$ —	$ —	$ —	$ —	$ —
Regulatory (asset) / liability	—	—	—	—	—
Recorded in Income Statement: gain / (loss)					
Revenue	—	—	—	0.2	0.2
Purchased Power	—	—	1.5	0.2	1.7
Fuel	—	0.1	—	—	0.1
O&M	—	—	—	—	—
Total	$ —	$ 0.1	$ 1.5	$ 0.4	$ 2.0

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The following tables show the fair value, balance sheet classification and hedging designation of DP&L's derivative instruments at December 31, 2015 and 2014.

Fair Values of Derivative Instruments

December 31, 2015

			Gross Amounts Not Offset in the Balance Sheets		
$ in millions	**Hedging Designation**	**Gross Fair Value as presented in the Balance Sheets**	**Financial Instruments with Same Counterparty in Offsetting Position**	**Cash Collateral**	**Net Amount**
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	**Designated**	**$ 16.2**	**$ (7.1)**	**$ —**	**$ 9.1**
Forward power contracts	**Not designated**	**7.4**	**(5.5)**	**—**	**1.9**
FTRs		**0.2**	**(0.2)**	**—**	**—**
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	**Designated**	**3.0**	**(2.4)**	**—**	**0.6**
Forward power contracts	**Not designated**	**4.0**	**(2.7)**	**—**	**1.3**
Total assets		**$ 30.8**	**$ (17.9)**	**$ —**	**$ 12.9**
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	**Designated**	**$ 7.1**	**$ (7.1)**	**$ —**	**$ —**
Forward power contracts	**Not designated**	**14.5**	**(5.5)**	**(8.0)**	**1.0**
FTRs	**Not designated**	**0.5**	**(0.2)**	**—**	**0.3**
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	**Designated**	**2.7**	**(2.4)**	**—**	**0.3**
Forward power contracts	**Not designated**	**2.7**	**(2.7)**	**—**	**—**
Total liabilities		**$ 27.5**	**$ (17.9)**	**$ (8.0)**	**$ 1.6**

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Fair Values of Derivative Instruments

December 31, 2014

$ in millions	Hedging Designation	Gross Fair Value as presented in the Balance Sheets	Gross Amounts Not Offset in the Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Designated	$ 5.6	$ (2.0)	$ —	$ 3.6
Forward power contracts	Not designated	5.6	(3.4)	—	2.2
FTRs	Not designated	—	—	—	—
Heating oil futures	Not designated	—	—	—	—
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	0.3	(0.3)	—	—
Forward power contracts	Not designated	3.6	(0.9)	—	2.7
Total assets		$ 15.1	$ (6.6)	$ —	$ 8.5
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 2.1	$ (2.0)	$ —	0.1
Forward power contracts	Not designated	7.5	(3.4)	(4.1)	—
FTRs	Not designated	0.6	—	—	0.6
Heating oil futures	Not designated	0.4	—	(0.4)	—
Natural gas futures	Not designated	0.1	—	(0.1)	—
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	0.6	(0.3)	(0.3)	—
Forward power contracts	Not designated	1.0	(0.9)	—	0.1
Total liabilities		$ 12.3	$ (6.6)	$ (4.9)	$ 0.8

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Credit risk-related contingent features
Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. Since our debt has fallen below investment grade, we are in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization of the MTM loss. Some of our counterparties to the derivative instruments have requested collateralization of the MTM loss.

The aggregate fair value of DP&L's derivative instruments that are in a MTM loss position at December 31, 2015 is $27.5 million. This amount is offset by $8.0 million of collateral posted directly with third parties and in a broker margin account which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $17.9 million. If DP&L debt were to fall below investment grade, DP&L could be required to post collateral for the remaining $1.6 million.

7. Debt

Long-term debt is as follows:

Long-term debt

$ in millions	**Interest Rate**	**Maturity**	**December 31, 2015**	December 31, 2014
First mortgage bonds	1.875%	2016	**$ 445.0**	$ 445.0
Pollution control series	4.7%	2028	**—**	35.3
Pollution control series	4.8%	2034	**—**	179.1
Pollution control series	4.8%	2036	**100.0**	100.0
Pollution control series - rates from: 0.02% - 0.12% and 0.04% - 0.15% (a)		2040	**—**	100.0
Pollution control series - rates from: 1.13% - 1.17%		2020	**200.0**	—
U.S. Government note	4.2%	2061	**18.1**	18.2
Unamortized debt discount			**(0.2)**	(0.5)
Subtotal			**762.9**	877.1
Less: current portion			**(444.9)**	(0.1)
Total			**$ 318.0**	$ 877.0

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At December 31, 2015, maturities of long-term debt are summarized as follows:

Due within the twelve months ending December 31, $ in millions		
2016	$	445.1
2017		0.1
2018		0.1
2019		0.2
2020		200.2
Thereafter		117.4
		763.1
Unamortized discount		(0.2)
Total long-term debt	$	762.9

Significant transactions
On December 31, 2015, DP&L borrowed $35.0 million from DPL at an interest rate of 2.67%. The notes were due on or before December 31, 2016 and were repaid on January 29, 2016.

On July 1, 2015, the $35.3 million of DP&L's 4.7% pollution control bonds due January 2028 and $41.3 million of DP&L's 4.8% pollution control bonds due January of 2034 were called at par and were redeemed with cash.

On July 31, 2015, DP&L refinanced its revolving credit facility. The new facility has a $175.0 million borrowing limit, a $50.0 million letter of credit sublimit, a feature that provides DP&L the ability to increase the size of the facility by an additional $100.0 million and a maturity date of July 2020. At December 31, 2015, there were two letters of credit in the amount of $1.4 million outstanding, with the remaining $173.6 million available to DP&L. Fees associated with this revolving credit facility were not material during the years ended December 31, 2015 or 2014. Prior to refinancing the facility on July 31, 2015, this facility had a $300.0 million borrowing limit, a five-year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature that provided DP&L the ability to increase the size of the facility by an additional $100.0 million.

On August 3, 2015, DP&L called $100.0 million of variable rate pollution control bonds due November 2040, terminated the amended standby letter of credit facilities that supported these pollution control bonds, and called $137.8 million of 4.8% pollution control bonds due January of 2034. DP&L also used cash to redeem $37.8 million of these bonds and refinanced the $200.0 million balance, with new variable interest rate pollution control bonds secured by first mortgage bonds in an equivalent amount. In connection with the sale of the new pollution control bonds, DP&L entered into a certain Bond Purchase and Covenants Agreement, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of DP&L.

On March 31, 2014, DP&L borrowed $15.0 million from DPL at an interest rate of LIBOR plus 2.0%. This note was due on or before April 30, 2014 and was repaid on April 30, 2014.

On September 19, 2013, DP&L closed a $445.0 million issuance of senior secured first mortgage bonds. These new bonds mature on September 15, 2016, and are secured by DP&L’s First & Refunding Mortgage. Substantially all property, plant and equipment of DP&L is subject to the lien of the First and Refunding Mortgage. Substantially concurrent with this transaction, DP&L redeemed $470.0 million of previously outstanding first mortgage bonds.

Debt covenants and restrictions
In connection with DP&L’s sale of $200.0 million of variable rate pollution control bonds dated August 1, 2015, DP&L entered into an unsecured revolving credit agreement and a Bond Purchase and Covenants Agreement. These agreements contain representations, warranties, covenants and defaults consistent with those contained in the revolving

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credit facilities loan documents of DP&L and have two financial covenants. The first measures Total Debt to Total Capitalization and is calculated, at the end of each fiscal quarter, by dividing total debt at the end of the quarter by total capitalization at the end of the quarter. The second financial covenant measures EBITDA to Interest Expense. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

As of December 31, 2015, DP&L was in compliance with all debt covenants, including the financial covenants described above and did not have any meaningful restrictions in its debt financing documents prohibiting dividends to its parent, DPL.

8. Income Taxes

DP&L's components of income tax expense were as follows:

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Computation of tax expense			
Federal income tax expense *(a)*	**$ 49.3**	$ 53.8	$ 35.5
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**0.4**	1.2	0.3
Depreciation of AFUDC - Equity	**(2.8)**	(2.7)	(2.5)
Investment tax credit amortized	**(2.4)**	(2.5)	(2.5)
Section 199 - domestic production deduction	**(6.1)**	(4.6)	(4.1)
Accrual (settlement) for open tax years	**—**	(6.6)	(8.8)
Other, net *(b)*	**(3.3)**	1.1	0.7
Total tax expense	**$ 35.1**	$ 39.7	$ 18.6
Components of Tax Expense			
Federal - current	**$ 55.8**	$ 34.1	$ 38.6
State and Local - current	**0.8**	0.5	(0.1)
Total current	**56.6**	34.6	38.5
Federal - deferred	**(21.0)**	4.1	(20.4)
State and local - deferred	**(0.5)**	1.0	0.5
Total deferred	**(21.5)**	5.1	(19.9)
Total tax expense	**$ 35.1**	$ 39.7	$ 18.6

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Effective and Statutory Rate Reconciliation
The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to DP&L's effective tax rate, as a percentage of income from continuing operations before taxes for the years ended December 31, 2015, 2014 and 2013:

	Years ended December 31,		
	2015	2014	2013
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
State taxes, net of Federal tax benefit	**0.3 %**	0.8 %	0.3 %
AFUDC - Equity	**(2.0)%**	(1.7)%	(2.4)%
Amortization of investment tax credits	**(1.7)%**	(1.6)%	(2.4)%
Section 199 - domestic production deduction	**(4.3)%**	(3.0)%	(4.0)%
Other - net	**(2.5)%**	(3.8)%	(8.3)%
Effective tax rate	**24.8 %**	25.7 %	18.2 %

Deferred Income Taxes
Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered. Investment tax credits related to utility property have been deferred and are being amortized over the estimated useful lives of the related property.

Components of Deferred Tax Assets and Liabilities

	December 31,	
$ in millions	**2015**	2014
Net non-current Assets / (Liabilities)		
Depreciation / property basis	**$ (608.8)**	$ (618.8)
Income taxes recoverable	**(12.0)**	(14.8)
Regulatory assets	**(11.5)**	(18.0)
Investment tax credit	**7.0**	8.6
Compensation and employee benefits	**3.6**	5.2
Other	**(9.5)**	(12.2)
Net non-current liabilities	**$ (631.2)**	$ (650.0)
Net current Assets / (Liabilities) *(c)*		
Other	**$ —**	$ 0.5
Net current assets / (liabilities)	**$ —**	$ 0.5

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes benefit of $0.4 million, expense of $0.7 million and benefit of $1.1 million in the years ended December 31, 2015, 2014 and 2013, respectively, of income tax related to adjustments from prior years.
(c) Amounts are included within Other prepayments and current assets and Other current liabilities on the Balance Sheets of DP&L.

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The following table presents the tax (benefit) / expense related to pensions, postemployment benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Tax expense / (benefit)	**$ 7.5**	$ (6.0)	$ 7.0

Uncertain Tax Positions

We apply the provisions of GAAP relating to the accounting for uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits for DP&L is as follows:

$ in millions	
Balance at December 31, 2013	$ 8.8
Calendar 2014	
Tax positions taken during prior period	2.8
Lapse of Statute of Limitations	(8.6)
Settlement with taxing authorities	—
Balance at December 31, 2014	3.0
Calendar 2015	
Tax positions taken during prior period	—
Lapse of Statute of Limitations	—
Balance at December 31, 2015	$ 3.0

Of the December 31, 2015 balance of unrecognized tax benefits, $0.9 million is due to uncertainty in the timing of deductibility.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The amounts accrued and expense (benefit) recorded were not material for each period presented.

Following is a summary of the tax years open to examination by major tax jurisdiction:

U.S. Federal – 2010 and forward
State and Local – 2010 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months other than those subject to expiring statute of limitations.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The results of the examination were approved by the Joint Committee on Taxation on January 18, 2013. As a result of the examination, DPL received a refund of $19.9 million and recorded a $1.2 million reduction to income tax expense in 2013.

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9. Benefit Plans

Defined contribution plans

DP&L sponsors two defined contribution plans. One is for non-union employees (the management plan) and one is for collective bargaining employees (the union plan). Both plans are qualified under Section 401 of the Internal Revenue Code.

Certain non-union employees become eligible to participate in the management plan on the first day of the month following the first full calendar month of employment; provided the employee worked at least 160 hours in that calendar month. Union employees become eligible to participate in the union plan on the first day of the first month following 30 days of employment. Effective January 1, 2016, employees in both plans are eligible to participate upon date of hire.

Participants may elect to contribute up to 85% of eligible compensation to their plan. Non-union participant contributions are matched 100% on the first 1% of eligible compensation and 50% on the next 5% of eligible compensation and they are fully vested in their employer contributions after 2 years of service. Union participant contributions are matched 150% but are capped at $2,100 for 2015 and they are fully vested in their employer contributions after 3 years of service. All participants are fully vested in their own contributions.

For the years ended December 31, 2015, 2014 and 2013 DP&L's contributions to all defined contribution plans were $4.8 million, $4.7 million and $4.8 million per year, respectively.

Defined benefit plans

DP&L sponsors a traditional defined benefit pension plan for most of the employees of DPL and its subsidiaries. For collective bargaining employees, the defined benefits are based on a specific dollar amount per year of service. For all other employees (management employees), the traditional defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this traditional pension plan was closed to new management employees. A participant is 100% vested in all amounts credited to his or her account upon the completion of five vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. Effective January 1, 2014, the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including among other companies, DPL and DP&L. Employees that transferred from DP&L to the Service Company maintain their previous eligibility to participate in the DP&L pension plan.

Almost all management employees beginning employment on or after January 1, 2011 participate in a cash balance pension plan. Similar to the traditional pension plan for management employees, the cash balance benefits are based on compensation and years of service. A participant shall become 100% vested in all amounts credited to his or her account upon the completion of three vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. Vested benefits in the cash balance plan are fully portable upon termination of employment.

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In addition, we have a Supplemental Executive Retirement Plan (SERP) for certain retired key executives. The SERP has an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. We also include our net liability to our partners related to our share of their pension costs within Pension, retiree and other benefits on our Balance Sheets.

We recognize an asset for a plan's overfunded status and a liability for a plan's underfunded status and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. For the transmission and distribution areas of our electric business, these amounts are recorded as regulatory assets and liabilities which represent the regulated portion that would otherwise be charged or credited to AOCI. We have historically recorded these costs on the accrual basis and this is how these costs have been historically recovered through customer rates. This factor, combined with the historical precedents from the PUCO and FERC, make these costs probable of future rate recovery.

Postretirement benefits

Qualified employees who retired prior to 1987 and their dependents are eligible for health care and life insurance benefits until their death, while qualified employees who retired after 1987 are eligible for life insurance benefits and partially subsidized health care. The partially subsidized health care is at the election of the employee, who pays the majority of the cost, and is available only from their retirement until they are covered by Medicare. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

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The following tables set forth the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets at December 31, 2015 and 2014. The amounts presented in the following tables for pension obligations include the collective bargaining plan formula, traditional management plan formula and cash balance plan formula and the SERP in the aggregate. The amounts presented for postemployment obligations include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at beginning of period	**$ 443.8**	$ 370.5
Service cost	**7.1**	5.9
Interest cost	**17.3**	17.5
Plan amendments	**—**	6.8
Actuarial (gain) / loss	**(34.5)**	67.3
Benefits paid	**(22.9)**	(24.2)
Benefit obligation at end of period	**410.8**	443.8
Change in plan assets		
Fair value of plan assets at beginning of period	**371.7**	349.1
Actual return on plan assets	**(8.8)**	46.4
Contributions to plan assets	**5.4**	0.4
Benefits paid	**(22.9)**	(24.2)
Fair value of plan assets at end of period	**345.4**	371.7
Funded status of plan	**$ (65.4)**	$ (72.1)

	December 31,	
	2015	2014
Amounts recognized in the Balance sheets		
Current liabilities	**$ (0.4)**	$ (0.4)
Non-current liabilities	**(65.0)**	(71.7)
Net liability at Year ended December 31,	**$ (65.4)**	$ (72.1)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 17.0**	$ 20.3
Net actuarial loss / (gain)	**139.7**	152.5
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 156.7**	$ 172.8
Recorded as:		
Regulatory asset	**$ 91.1**	$ 99.0
Regulatory liability	**—**	—
Accumulated other comprehensive income	**65.6**	73.8
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 156.7**	$ 172.8

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$ in millions	Postretirement	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at beginning of period	**$ 19.6**	$ 19.7
Service cost	**0.2**	0.2
Interest cost	**0.6**	0.8
Actuarial (gain) / loss	**(1.1)**	0.2
Benefits paid	**(1.5)**	(1.3)
Benefit obligation at end of period	**17.8**	19.6
Change in plan assets		
Fair value of plan assets at beginning of period	**3.3**	3.7
Contributions to plan assets	**1.0**	0.9
Benefits paid	**(1.5)**	(1.3)
Fair value of plan assets at end of period	**2.8**	3.3
Funded status of plan	**$ (15.0)**	$ (16.3)
	December 31,	
	2015	2014
Amounts recognized in the Balance sheets		
Current liabilities	**$ (0.4)**	$ (0.5)
Non-current liabilities	**(14.6)**	(15.8)
Net liability at Year ended December 31,	**$ (15.0)**	$ (16.3)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 0.5**	$ 0.6
Net actuarial loss / (gain)	**(6.2)**	(5.8)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.7)**	$ (5.2)
Recorded as:		
Regulatory asset	**$ 0.3**	$ —
Regulatory liability	**(5.1)**	(4.5)
Accumulated other comprehensive income	**(0.9)**	(0.7)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.7)**	$ (5.2)

The accumulated benefit obligation for our defined benefit pension plans was $401.2 million and $431.0 million at December 31, 2015 and 2014, respectively.

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The net periodic benefit cost of the pension and postretirement plans were:

Net Periodic Benefit Cost - Pension

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Service cost	**$ 7.1**	$ 5.9	$ 7.2
Interest cost	**17.3**	17.5	15.6
Expected return on assets (a)	**(22.6)**	(22.9)	(23.6)
Amortization of unrecognized:			
Actuarial gain	**9.8**	6.4	9.3
Prior service cost	**3.3**	2.8	2.8
Net periodic benefit cost	**$ 14.9**	$ 9.7	$ 11.3

Net Periodic Benefit Cost - Postretirement

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Service cost	**$ 0.2**	$ 0.2	$ 0.2
Interest cost	**0.6**	0.8	0.8
Expected return on assets (a)	**(0.1)**	(0.2)	(0.2)
Amortization of unrecognized:			
Actuarial loss	**(0.6)**	(0.8)	(0.7)
Prior service cost	**0.1**	0.1	0.1
Net periodic benefit cost	**$ 0.2**	$ 0.1	$ 0.2

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Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities

Pension

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Net actuarial loss / (gain)	**$ (3.0)**	$ 43.8	$ (11.7)
Prior service cost	**—**	6.8	—
Reversal of amortization item:			
Net actuarial loss	**(9.8)**	(6.4)	(9.3)
Prior service cost	**(3.3)**	(2.8)	(2.8)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (16.1)**	$ 41.4	$ (23.8)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (1.2)**	$ 51.1	$ (12.5)

Postretirement

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Net actuarial loss / (gain)	**$ (1.1)**	$ 0.4	$ (1.9)
Reversal of amortization item:			
Net actuarial gain	**0.6**	0.8	0.7
Prior service credit	**(0.1)**	(0.1)	(0.1)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (0.6)**	$ 1.1	$ (1.3)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (0.4)**	$ 1.2	$ (1.1)

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2016 are:

$ in millions	Pension	Postretirement
Actuarial gain / (loss)	$ 7.2	$ (0.8)
Prior service cost	$ 3.1	$ 0.1

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Assumptions

Our expected return on plan asset assumptions, used to determine benefit obligations, are based on historical long-term rates of return on investments, which use the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors, such as inflation and interest rates, as well as asset diversification and portfolio rebalancing, are evaluated when long-term capital market assumptions are determined. Peer data and historical returns are reviewed to verify reasonableness and appropriateness.

At December 31, 2015, we are maintaining our long term rate of return assumption of 6.50% for pension plan assets. In addition, we are decreasing our long-term rate of return assumption to 3.90% from 4.50% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our long-term portfolio mixes. Also, at December 31, 2015, we have increased our assumed discount rate to 4.49% from 4.02% for pension and to 4.10% from 3.71% for postemployment benefits expense to reflect current duration-based yield curve discount rates. A one percent increase in the rate of return assumption for pension would result in a decrease in pension expense of approximately $3.5 million. A 1% decrease in the rate of return assumption for pension would result in an increase in pension expense of approximately $3.5 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.2 million to 2016 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.3 million to 2016 pension expense. A one percent change in the assumed health care cost trend rate would affect postemployment benefit costs by less than $1.0 million.

In determining the discount rate to use for valuing liabilities, we used a market yield curve on high-quality fixed income investments as of December 31, 2015. We project the expected benefit payments under the plan based on participant data and based on certain assumptions concerning mortality, retirement rates, termination rates, etc. The expected benefit payments for each year are then discounted back to the measurement date using the appropriate spot rate for each half-year from the yield curve, thereby obtaining a present value of all expected future benefit payments using the yield curve. Finally, an equivalent single discount rate is determined which produces a present value equal to the present value determined using the full yield curve.

Effective January 1, 2016 we will apply the spot rate approach for determining service cost and interest cost for its defined benefit pension plans and other post-retirement plan. The expected 2016 service costs and interest costs included above reflect the change in methodology. The impact of the change in approach is a reduction in: (1) expected service costs of $0.4 million for pension plans in 2016 ($0.4 million Defined Benefit Pension Plan and $0.0 million Supplemental Retirement Plan), and (2) expected interest costs of $3.2 million for pension plans in 2016 ($3.1 million Defined Benefit Pension Plan and $0.1 million Supplemental Retirement Plan).

The weighted average assumptions used to determine benefit obligations during the years ended December 31, 2015, 2014 and 2013 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate for obligations	**4.49%**	4.02%	4.86%	**4.10%**	3.71%	4.58%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2015, 2014 and 2013 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate	**4.02%**	4.86%	4.04%	**3.81%**	4.51%	4.58%
Expected rate of return on plan assets	**6.50%**	6.75%	6.75%	**4.50%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

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The assumed health care cost trend rates at December 31, 2015, 2014 and 2013 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2015	2014	2013	**2015**	2014	2013
Pre - age 65						
Current health care cost trend rate	**6.97%**	7.75%	8.00%	**6.85%**	6.97%	7.75%
Year trend reaches ultimate	**2029**	2023	2019	**2036**	2029	2023
Post - age 65						
Current health care cost trend rate	**6.97%**	6.75%	7.50%	**6.85%**	6.97%	6.75%
Year trend reaches ultimate	**2029**	2021	2018	**2036**	2029	2021
Ultimate health care cost trend rate	**4.50%**	5.00%	5.00%	**4.50%**	4.50%	5.00%

The assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects on the net periodic postemployment benefit cost and the accumulated postemployment benefit obligation:

Effect of change in health care cost trend rate

$ in millions	One-percent increase	One-percent decrease
Service cost plus interest cost	$ 0.1	$ —
Benefit obligation	$ 1.1	$ (0.7)

Pension plan assets

Plan assets are invested using a total return investment approach whereby a mix of equity securities, debt securities and other investments are used to preserve asset values, diversify risk and achieve our target investment return benchmark. Investment strategies and asset allocations are based on careful consideration of plan liabilities, the plan's funded status and our financial condition. Investment performance and asset allocation are measured and monitored on an ongoing basis.

Plan assets are managed in a balanced portfolio comprised of two major components: an equity portion and a fixed income portion. The expected role of plan equity investments is to maximize the long-term real growth of plan assets, while the role of fixed income investments is to generate current income, provide for more stable periodic returns and provide some protection against a prolonged decline in the market value of plan equity investments.

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Long-term strategic asset allocation guidelines, as well as short-term tactical asset allocation guidelines, are determined by a Risk/Advisory Committee and approved by a Fiduciary Committee. These allocations take into account the Plan's long-term objectives. The long-term target allocations for plan assets are 18% – 38% for equity securities and 58% – 86% for fixed income securities. Equity securities include U.S. and international equity, while fixed income securities include long-duration and high-yield bond funds and emerging market debt funds.

Tactically, the committees, on a short-term basis, will make asset allocations that are outside the long-term allocation guidelines. The short-term allocation positions are likely to not exceed one-year in duration. In addition to the equity and fixed income investments, the short-term allocation may also include a relatively small allocation to alternative investments. The plan currently has a small allocation to a core property fund, as well as a small allocation to a hedge fund.

Most of our Plan assets are measured using quoted, observable prices which are considered Level One inputs in the Fair Value Hierarchy. The Core property collective fund and the Common collective fund are measured using Level Two inputs that are quoted prices for identical assets in markets that are less active.

The following table summarizes our target pension plan allocation for 2015:

		Percentage of plan assets as of December 31,	
Asset Category	Long-Term Mid-Point Target Allocation	2015	2014
Equity Securities	28%	17%	18%
Debt Securities	72%	67%	69%
Real Estate	—%	9%	7%
Other	—%	7%	6%

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The fair values of our pension plan assets at December 31, 2015 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2015

Asset Category $ in millions	**Market Value at December 31, 2015**	**Quoted prices in active markets for identical assets** (Level 1)	**Significant observable inputs** (Level 2)	**Significant unobservable inputs** (Level 3)
Equity securities *(a)*				
Small/Mid cap equity	$ 9.2	$ 9.2	$ —	$ —
Large cap equity	20.2	20.2	—	—
International equity	18.2	18.2	—	—
Emerging markets equity	2.7	2.7	—	—
SIIT dynamic equity	10.0	10.0	—	—
Total equity securities	60.3	60.3	—	—
Debt Securities *(b)*				
Emerging markets debt	6.3	6.3	—	—
High yield bond	6.3	6.3	—	—
Long duration fund	219.5	219.5	—	—
Total debt securities	232.1	232.1	—	—
Other investments *(c)*				
Core property collective fund	30.2	—	30.2	—
Common collective fund	22.8	—	22.8	—
Total other investments	53.0	—	53.0	—
Total pension plan assets	$ 345.4	$ 292.4	$ 53.0	$ —

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(b) This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category represents a property fund that invests in commercial real estate and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

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The fair values of our pension plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2014

Asset Category $ in millions	Market Value at December 31, 2014	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Equity securities (a)				
Small/Mid cap equity	$ 10.6	$ 10.6	$ —	$ —
Large cap equity	22.2	22.2	—	—
International equity	18.2	18.2	—	—
Emerging markets equity	2.8	2.8	—	—
SIIT dynamic equity	11.6	11.6	—	—
Total equity securities	65.4	65.4	—	—
Debt Securities (b)				
Emerging markets debt	6.0	6.0	—	—
High yield bond	6.5	6.5	—	—
Long duration fund	242.7	242.7	—	—
Total debt securities	255.2	255.2	—	—
Cash and cash equivalents (c)				
Cash	1.6	1.6	—	—
Other investments (d)				
Core property collective fund	26.3	—	26.3	—
Common collective fund	23.2	—	23.2	—
Total other investments	49.5	—	49.5	—
Total pension plan assets	$ 371.7	$ 322.2	$ 49.5	$ —

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(b) This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a property fund that invests in commercial real estate and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

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The fair values of our other postemployment benefit plan assets at December 31, 2015 by asset category are as follows:

Fair Value Measurements for Other Postemployment Benefit Plan Assets at December 31, 2015

Asset Category $ in millions	**Fair Value at December 31, 2015 (a)**	**Quoted prices in active markets for identical assets**	**Significant observable inputs**	**Significant unobservable inputs**
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund *(a)*	**$ 2.8**	**$ 2.8**	**$ —**	**$ —**

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

The fair values of our other postemployment benefit plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Other Postemployment Benefit Plan Assets at December 31, 2014

Asset Category $ in millions	Fair Value at December 31, 2014 (a)	Quoted prices in active markets for identical assets	Significant observable inputs	Significant unobservable inputs
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund *(a)*	$ 3.2	$ 3.2	$ —	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

Pension funding

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. We contributed $5.0 million, $0.0 million, and $0.0 million during the years ended December 31, 2015, 2014 and 2013, respectively.

We expect to make contributions of $0.4 million to our SERP in 2016 to cover benefit payments. We also expect to contribute $1.1 million to our other postemployment benefit plans in 2016 to cover benefit payments. We made contributions of $5.0 million to our pension plan during January, 2016.

The Pension Protection Act of 2006 (the Act) contained new requirements for our single employer defined benefit pension plan. In addition to establishing a 100% funding target for plan years beginning after December 31, 2008, the Act also limits some benefits if the funded status of pension plans drops below certain thresholds. Among other restrictions under the Act, if the funded status of a plan falls below a predetermined ratio of 80%, lump-sum payments to new retirees are limited to 50% of amounts that otherwise would have been paid and new benefit improvements may not go into effect. For the 2015 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 112.54% and is estimated to be 112.54% until the 2016 status is certified in September 2016 for the 2016 plan year. The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, grants plan sponsors certain relief from funding requirements and benefit restrictions of the Act.

Benefit payments, which reflect future service, are expected to be paid as follows:

Estimated future benefit payments and Medicare Part D reimbursements

$ in millions due within the following years:	Pension	Postretirement
2016	$ 24.6	$ 1.7
2017	$ 25.2	$ 1.6
2018	$ 25.8	$ 1.5
2019	$ 26.3	$ 1.4
2020	$ 26.7	$ 1.4
2021 – 2025	$ 134.8	$ 5.7

10. Equity

Redeemable Preferred Stock
DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding at December 31, 2015. DP&L also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding at December 31, 2015. The table below details the preferred shares outstanding at December 31, 2015 and 2014:

		December 31, 2015 and 2014		Par Value ($ in millions)	
	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	**December 31, 2015**	December 31, 2014
DP&L Series A	3.75%	$ 102.50	93,280	**$ 9.3**	$ 9.3
DP&L Series B	3.75%	$ 103.00	69,398	**7.0**	7.0
DP&L Series C	3.90%	$ 101.00	65,830	**6.6**	6.6
Total			228,508	**$ 22.9**	$ 22.9

The DP&L preferred stock may be redeemed at DP&L's option as determined by its Board of Directors at the per-share redemption prices indicated above, plus cumulative accrued dividends, of which there were none at December 31, 2015. In addition, DP&L's Amended Articles of Incorporation contain provisions that permit preferred stockholders to elect members of the Board of Directors in the event that cumulative dividends on the preferred stock are in arrears in an aggregate amount equivalent to at least four full quarterly dividends. Since this potential redemption-triggering event is not solely within the control of DP&L, the preferred stock is presented on the Balance Sheets as "Redeemable Preferred Stock" in a manner consistent with temporary equity.

Dividend Restrictions
As long as any DP&L preferred stock is outstanding, DP&L's Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of DP&L available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted DP&L's ability to pay cash dividends and, as of December 31, 2015, DP&L's retained earnings of 437.3 million were all available for common stock dividends payable to DPL. We do not expect this restriction to have an effect on the payment of cash dividends in the future.

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Common Stock
DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2015. All common shares are held by DP&L's parent, DPL.

As part of the PUCO's approval of the Merger, **DP&L** agreed to maintain a capital structure that includes an equity ratio of at least 50 percent and not to have a negative retained earnings balance.

11. Contractual Obligations, Commercial Commitments and Contingencies

DP&L – Equity Ownership Interest
DP&L has a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. At December 31, 2015, DP&L could be responsible for the repayment of 4.9%, or $74.5 million, of a $1,519.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2016 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2015, we have no knowledge of such a default.

Contractual Obligations and Commercial Commitments
We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2015, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Coal contracts *(a)*	374.2	186.9	187.3	—	—
Purchase orders and other contractual obligations	83.8	24.4	30.0	29.4	—

(a) Total at DP&L operated units.

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. At December 31, 2015, 73% of our future committed coal obligations are with a single supplier. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Purchase orders and other contractual obligations:
At December 31, 2015, DP&L had various other contractual obligations, including non-cancelable contracts, to purchase goods and services with various terms and expiration dates.

Contingencies
In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations, and other matters, including the matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2015, cannot be reasonably determined.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Environmental Matters
DP&L's facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including SIPs) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO2, particulates, mercury, acid gases, NOx, and other air emissions. DP&L has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and reductions of GHGs,
- Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and
- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $0.9 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable or a loss cannot be reasonably estimated. We evaluate the potential liability related to environmental matters quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material adverse effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our coal-fired generation units. Some of these matters could have material adverse impacts on the operation of the power stations.

12. Related Party Transactions

In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including operations, accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including, among other companies, DPL and DP&L. The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable allocations. This includes ensuring that the regulated utilities served, including DP&L, are not subsidizing costs incurred for the benefit of other businesses.

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NOTES TO FINANCIAL STATEMENTS (Continued)

The following table provides a summary of these transactions:

	Years ended December 31,		
$ in millions	**2015**	2014	2013
DP&L revenues:			
Sales to DPLER (including MC Squared) *(a)*	**$ 303.3**	$ 487.1	$ 453.9
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC *(b)*	**$ (3.2)**	$ (2.9)	$ (2.9)
Expense recoveries for services provided to DPLER *(c)*	**$ 2.4**	$ 2.2	$ 5.2
Transactions with the Service Company:			
Charges for services provided	**$ 30.9**	$ 30.5	$ —
Charges to the Service Company	**$ 6.1**	$ 2.3	$ —

Balances with related parties:	**At December 31, 2015**	At December 31, 2014
Net payable to the Service Company	**$ (0.5)**	$ (4.7)
Short-term loan with DPL Inc.	**$ 35.0**	$ —
Deposits received from DPLER *(d)*	**$ —**	$ 20.1

(a) DP&L sold power to DPLER and MC Squared to satisfy the electric requirements of their retail customers. The revenue dollars associated with sales to DPLER and MC Squared are recorded as wholesale revenues in DP&L's Financial Statements. These agreements were terminated on the sale of DPLER on January 1, 2016.

(b) MVIC, a wholly-owned captive insurance subsidiary of DPL, provides insurance coverage to DP&L and other DPL subsidiaries for workers' compensation, general liability, property damages and directors' and officers' liability. These amounts represent insurance premiums paid by DP&L to MVIC.

(c) In the normal course of business DP&L incurs and records expenses on behalf of DPLER. Such expenses include but are not limited to employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. DP&L subsequently charges these expenses to DPLER at DP&L's cost and credits the expense in which they were initially recorded.

(d) DP&L requires credit assurance from the CRES providers serving customers in its service territory because DP&L is the default energy provider should the CRES provider fail to fulfill its obligations to provide electricity. Due to DPL's credit downgrade, DP&L required cash collateral from DPLER.

Income taxes

AES files federal and state income tax returns which consolidate DPL and its subsidiaries, including DP&L. Under a tax sharing agreement with DPL, DP&L is responsible for the income taxes associated with its own taxable income and records the provision for income taxes using a separate return method. DP&L had a net receivable balance under this agreement of $1.5 million and $1.0 million as of December 31, 2015 and 2014, respectively, which is recorded in Other current assets on the accompanying Balance Sheets.

13. Fixed-asset Impairment

	Years ended December 31,		
	2015	2014	2013
East Bend	$ —	$ —	$ 76.0
Conesville	—	—	10.0
Total fixed-asset impairment expense	$ —	$ —	$ 86.0

East Bend and Conesville - During the fourth quarter of 2013, DP&L tested the recoverability of long-lived assets at Conesville, a 129 MW coal-fired station in Ohio, and East Bend, a 186 MW coal-fired station in Kentucky jointly-owned by DP&L. Gradual decreases in power prices, as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of DPL failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator for the DP&L long-lived assets. DP&L performed a long-lived asset impairment test and determined that the carrying amounts of the asset groups were not recoverable. The long-lived asset group subject to the impairment evaluation was determined to be each individual station of DP&L. This determination was based on the assessment of the stations' ability to generate independent cash flows. The Conesville and East Bend asset groups were each determined to have a zero fair value using discounted cash flows under the income approach. As a result, DP&L recognized an asset impairment expense of $10.0 million and $76.0 million for Conesville and East Bend, respectively.

14. Subsequent Event

On January 1, 2016, DPL closed on the sale of DPLER to IGS. Also on January 1, 2016, DP&L terminated the contract it had with DPLER for the supply of electricity. The agreement terminating the contract was signed on December 28, 2015 and DP&L received $27.7 million of restricted cash on December 31, 2015 for the early termination of the contract, which we expect to record as a gain in the first quarter of 2016. This amount is shown as Restricted cash with the associated liability shown as Advance on contract termination on the Balance Sheet as of December 31, 2015. As the cash we received was restricted upon receipt it is not shown on the Statement of Cash Flows.

On February 22, 2016 DP&L filed an application to update its Electric Security Plan ("ESP") for new rates effective January 1, 2017. As part of this filing, DP&L is seeking a Reliable Electricity Rider for 10 years, based on the variance between the proposed revenue requirement and the actual revenues net of operating costs of the generation units. The ESP establishes the terms and conditions for DP&L's Standard Service Offer ("SSO") that applies to customers that do not choose a competitive retail electric supplier. In the ESP, DP&L recommends including renewable energy attributes as part of the product that is competitively bid, and seeks recovery of approximately $10.0 million of regulatory assets. The ESP also proposes a new Distribution Investment Rider to allow DP&L to recover costs associated with future distribution equipment and infrastructure needs. Additionally, the ESP establishes new riders set initially at zero, related to energy reductions from DP&L's energy efficiency programs, and certain environmental liabilities DP&L may incur. There can be no assurance that the ESP will be approved as filed or on a timely basis, and if the ESP is not approved on a timely basis or if the final ESP provides for terms that are more adverse than those submitted in DP&L's application, our results of operations, financial condition and cash flows could be materially impacted.

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NOTES TO FINANCIAL STATEMENTS (Continued)

15. Cash Flow Statement Items

A. Cash Flow Statement Reconciliation (Instruction 2, p. 120):

	2015 Beginning Balance	2015 Ending Balance
Balance Sheet (p. 110, line 35)	$ 5,385,771	$ 5,361,401
Balance Sheet (p. 110, line 38)	0	0
Cash and Cash Equivalents (p. 121, lines 88 and 90)	$ 5,385,771	$ 5,361,401

B. Interest and Income Taxes (Instruction 3, p. 120):

	2015	2014
Cash paid during the year for:		
Interest (net of amount capitalized)	$ 27,547,640	$ 26,625,338
Income taxes (net of refunds)	$ 828,058	$ 738,170

C. Statement of Cash Flows

	For the year ended December 31, 2015
Net Cash Flow from Operating Activities:	
Net income	$106,439,866
Depreciation and depletion	138,158,974
Taxes applicable to subsequent years	(3,713,869)
Pension and retire benefits	(730,487)
Deferred income taxes, net	(19,202,849)
Prepaid taxes	(1,295,475)
Investment tax credit adjustment, net	(2,505,971)
Investment tax credit adjustment, net	(2,392,826)
Net (increase) decrease in receivables	11,855,920
Net (increase) decrease in inventory	(9,098,026)
Net increase (decrease) in payables and accrued expenses	69,490
Net (increase) decrease in other regulatory assets	21,752,515
(Less) allowance for other funds used during construction	(1,609,917)
Other	12,682,985
Other (deferred debits / credits)	3,777,757
Net Cash Provided by (Used In) Operating Activities	256,694,058

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	For the year ended December 31, 2015
Cash Flows from Investment Activities:	
Gross additions to utility plant (less nuclear fuel)	(127,011,486)
Cash outflows from plant	(127,011,486)
Proceeds from disposal of noncurrent assets	8,802
Net (increase) decrease in restricted cash	(279,613)
Other	4,792,991
Net Cash Used in Investing Activities	(122,489,306)
Cash Flows from Financing Activities:	
Proceeds from issuance in long-term debt	200,000,000
Other (provide details in footnote):	(3,856,229)
Payment for retirement of long-term debt	(314,506,113)
Net decrease in short-term debt	35,000,000
Dividends on preferred stock	(866,780)
Dividends on common stock	(50,000,000)
Net Cash Used in Financing Activities	(134,229,122)
Net increase (decrease) in cash and cash equivalents	(24,370)
Cash and cash equivalents at beginning of year	5,385,771
Cash and cash equivalents at end of year	$ 5,361,401

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	760,176	(33,702,629)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(98,046)	(12,106,997)		
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)	(98,046)	(12,106,997)		
5	Balance of Account 219 at End of Preceding Quarter/Year	662,130	(45,809,626)		
6	Balance of Account 219 at Beginning of Current Year	662,130	(45,809,626)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(196,126)	5,475,291		
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)	(196,126)	5,475,291		
10	Balance of Account 219 at End of Current Quarter/Year	466,004	(40,334,335)		

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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	5,213,067	1,007,490	(26,721,896)		
2	(1,097,488)	(2,313,429)	(15,615,960)		
3					
4	(1,097,488)	(2,313,429)	(15,615,960)	115,021,539	99,405,579
5	4,115,579	(1,305,939)	(42,337,856)		
6	4,115,579	(1,305,939)	(42,337,856)		
7	(1,097,488)	9,441,302	13,622,979		
8					
9	(1,097,488)	9,441,302	13,622,979	106,439,866	120,062,845
10	3,018,091	8,135,363	(28,714,877)		

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)	5,233,545,621	5,233,545,621
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	114,058,701	114,058,701
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,347,604,322	5,347,604,322
9	Leased to Others		
10	Held for Future Use	1,058,544	1,058,544
11	Construction Work in Progress	78,020,708	78,020,708
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,426,683,574	5,426,683,574
14	Accum Prov for Depr, Amort, & Depl	2,815,125,117	2,815,125,117
15	Net Utility Plant (13 less 14)	2,611,558,457	2,611,558,457
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	-2,765,892,911	-2,765,892,911
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	-49,232,206	-49,232,206
22	Total In Service (18 thru 21)	-2,815,125,117	-2,815,125,117
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	-2,815,125,117	-2,815,125,117

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
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					30
					31
					32
					33

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		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

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		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	90,693,947	3,642,310
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	90,693,947	3,642,310
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	12,055,127	-3,118
9	(311) Structures and Improvements	439,978,256	858,509
10	(312) Boiler Plant Equipment	1,748,435,306	13,060,087
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	358,778,369	2,174,751
13	(315) Accessory Electric Equipment	244,036,692	174,803
14	(316) Misc. Power Plant Equipment	51,237,995	1,121,062
15	(317) Asset Retirement Costs for Steam Production	10,229,250	40,325,208
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,864,750,995	57,711,302
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	546,528	74,782
38	(341) Structures and Improvements	2,023,974	
39	(342) Fuel Holders, Products, and Accessories	3,957,381	
40	(343) Prime Movers		
41	(344) Generators	85,872,621	40,061
42	(345) Accessory Electric Equipment	4,368,727	798,886
43	(346) Misc. Power Plant Equipment	1,233,693	
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	98,002,924	913,729
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,962,753,919	58,625,031

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	30,035,198	-63,340
49	(352) Structures and Improvements	11,477,049	3,336,066
50	(353) Station Equipment	199,337,603	6,358,458
51	(354) Towers and Fixtures	30,547,264	246,960
52	(355) Poles and Fixtures	86,163,274	1,257,357
53	(356) Overhead Conductors and Devices	73,801,039	1,199,350
54	(357) Underground Conduit	651,739	1,266,412
55	(358) Underground Conductors and Devices	917,471	896,057
56	(359) Roads and Trails	9,439	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	432,940,076	14,497,320
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	25,991,912	931,144
61	(361) Structures and Improvements	52,259,803	3,736,560
62	(362) Station Equipment	305,710,887	14,575,051
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	266,402,840	7,564,677
65	(365) Overhead Conductors and Devices	160,546,048	8,385,797
66	(366) Underground Conduit	14,054,076	3,359,640
67	(367) Underground Conductors and Devices	214,746,699	9,112,084
68	(368) Line Transformers	283,192,442	18,380,690
69	(369) Services	205,859,582	11,590,167
70	(370) Meters	48,023,243	5,717,862
71	(371) Installations on Customer Premises	15,908,280	692,100
72	(372) Leased Property on Customer Premises	47,450	
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,592,743,262	84,045,772
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	1,608,881	
87	(390) Structures and Improvements	17,274,054	27,845
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment		
90	(393) Stores Equipment	436,521	
91	(394) Tools, Shop and Garage Equipment	7,818,715	
92	(395) Laboratory Equipment	4,804,722	-135,551
93	(396) Power Operated Equipment	2,229,174	
94	(397) Communication Equipment		
95	(398) Miscellaneous Equipment	1,067,204	28,665
96	SUBTOTAL (Enter Total of lines 86 thru 95)	35,239,271	-79,041
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)	35,239,271	-79,041
100	TOTAL (Accounts 101 and 106)	5,114,370,475	160,731,392
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)	5,114,370,475	160,731,392

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
					2
					3
21,985,211	524		72,351,570		4
21,985,211	524		72,351,570		5
					6
					7
			12,052,009		8
42,591	1,934,591		442,728,765		9
1,885,027	101,768,164	183,292	1,861,561,822		10
					11
710,933	7,093,226		367,335,413		12
2,020	1,029,329	-191,935	245,046,869		13
	100,272	8,643	52,467,972		14
	993,441		51,547,899		15
2,640,571	112,919,023		3,032,740,749		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			621,310		37
			2,023,974		38
			3,957,381		39
					40
-44,196			85,956,878		41
-8,796			5,176,409		42
-2,580			1,236,273		43
					44
-55,572			98,972,225		45
2,584,999	112,919,023		3,131,712,974		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
			29,971,858		48
26,777			14,786,338		49
1,721,637			203,974,424		50
110,766			30,683,458		51
1,181,014			86,239,617		52
346,307			74,654,082		53
			1,918,151		54
73,375			1,740,153		55
			9,439		56
					57
3,459,876			443,977,520		58
					59
11,664			26,911,392		60
499,347			55,497,016		61
2,424,125			317,861,813		62
					63
227,988			273,739,529		64
3,733,505			165,198,340		65
913			17,412,803		66
1,147,556			222,711,227		67
-52,772			301,625,904		68
25,422			217,424,327		69
2,415,208			51,325,897		70
48,053			16,552,327		71
			47,450		72
					73
					74
10,481,009			1,666,308,025		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,608,881		86
			17,301,899		87
					88
					89
			436,521		90
150,207			7,668,508		91
71,660			4,597,511		92
913,433			1,315,741		93
					94
770,697			325,172		95
1,905,997			33,254,233		96
					97
					98
1,905,997			33,254,233		99
40,417,092	112,919,547		5,347,604,322		100
					101
					102
					103
40,417,092	112,919,547		5,347,604,322		104

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					
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19					
20					
21					
22					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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				
3	Rights-of-Way & Land for Future Transmission Lines *	1/1/1961	**	269,799
4				
5	Parcels of Land at Stuart Station	1/1/1999	**	630,357
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23	Various Other Property	1/1/1934	**	158,388
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36	(*) Amounts were recorded on Account 101 on			
37	Respondent's books prior to 1970			
38				
39	(**) Various dates			
40				
41				
42				
43				
44				
45				
46				
47	Total			1,058,544

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRODUCTION - Stuart (*)	
2	Carter Hollow Landfill Construction	9,908,459
3	Asset Performance Management System	732,709
4	Gypsum Stack Out Area Concrete Base	587,302
5	Combustible Dust Improvements	553,059
6	Archaeological Study Baldwin & Elk Creek Run Crossing	511,047
7	Mercury Effluent Compliance	487,435
8	NERC Compliance - 2015	429,060
9	Precipitator Switched Mode Power Supplies- Unit 3	350,979
10	Jet Bubbling Reactor (JBR) Sump Upgrade- Unit 4	279,639
11	One Step Ahead (Osa) Security Initiative- Stuart	177,069
12	Landfilling Activities- 2015	154,194
13	Spare Turnbine Blades	153,490
14	Vestibule Replacement- Unit 2	148,750
15	Boiler Feed Pump Recirculation Valve Replacement- Unit 2	132,330
16	SCR Catalyst- Unit 4	128,356
17	Loto Program	118,248
18	Boiler Cameras- Unit 2	109,632
19	Boiler Plant Equipment	109,082
20	Pond 7A Outlet Pipe Replacement	89,973
21	DCS Upgrade- Control Processors- Unit 2	85,207
22	1C Pulverizer Rebuild	65,691
23	Outfall 019	61,425
24	Turbine Control System Upgrade- Unit 2	48,346
25	B Gas Cooling Pump Strainer Housing- Unit 3	38,313
26	B Gas Cooling Pump Strainer Housing- Unit 4	38,313
27	C Gas Cooling Pump Strainer Housing- Unit 4	38,313
28	2B Pulverizer Rebuild	37,891
29	Minor Projects	35,035
30	BFP Recirculation System- Unit 3	32,375
31	Turbogenerator Units	29,750
32	Accessory Elec Equipment	29,750
33	250 System Reclaim Plc Upgrades	27,144
34	Economizer Bypass Inlet A&B Exp. Joint- Unit 2	19,374
35	Hydrogen Seal Oil Fire Protection- Unit 3	18,395
36		
37		
38		
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Dynegy and/or	
42	AEP.	
43	TOTAL	78,020,708

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	PRODUCTION - Zimmer (*)	
2	Sequence 4 Landfill	2,206,851
3	LP Generator Rotor Replacement	1,177,277
4	Replace Air Preheater Modules 2 & 3	1,501,767
5	Air Preheater #2 Rotor Module	678,174
6	Lp Generator Rotor	506,151
7	Feedwater Heater Replacement	499,004
8	Reagent Injection System	471,907
9	Future Environmental Air Re-Emission Chemical	431,833
10	Hpt Valve Rebuilds 2013-2015	366,394
11	Hp Turbine Above Seat Drain	301,694
12	SCR Catalyst Replacement	268,772
13	Precipitator Wire Replacement	265,053
14	Conveyor 4-5 West Overhaul	264,269
15	Conveyor 4-5 West Overhaul	264,090
16	Gr Fan Overhaul #1	226,949
17	LPT Valve	226,096
18	Station Battery Replacement	224,746
19	RHO Replacement	194,099
20	CBU Buckets And Chains	169,860
21	Sliding Pressure Valve Rebuild	166,229
22	Conveyor 1-2 Belly Pans	165,376
23	Landfill Phase 2 Perime	151,436
24	Pulverizer Overhaul #2	150,231
25	Surge Bin #3 Liner Replace	147,816
26	UAT1 Overhaul	137,848
27	Oxidizer Overhaul	134,867
28	LP Generator Bushing Replacements	127,180
29	LBU/Conveyor Plc	118,877
30	Prim. & Sec. Sprhtr Bypass	85,554
31	Burner Replacement	79,854
32	Hydroclone Overhauls	71,533
33	Condensate Clean Up System Overhaul	60,520
34	Module Outlet Guillotines	55,056
35	SCR Sonic Horns	45,472
36	ID Fan Damper Drive Replacement	42,494
37	F.E. - Air: Hg Sorbent Trap	36,899
38	LP Fw Heater Level Sensor Alarm	24,831
39	Gas Lighter Conversion	19,882
40	Minor Projects	12,008
41	(*) Respondent's portion of undivided ownership in generating facilities with Dynegy and/or	
42	AEP.	
43	TOTAL	78,020,708

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	PRODUCTION - Miami Fort (*)	
2	Gas Lighter Conversions	1,939,805
3	PAH Preheat Coil Replacement	905,061
4	F.E. Air Re-Emission Chemical	630,328
5	Future Environmental Air Re-Emission Chemical- Unit 7 & Unit 8	483,751
6	Replace 7-7B FWH	422,247
7	Lawrenceburg Rd Landfill Area 2A Development	412,049
8	Neutral High Voltage Bushi- Unit 7	265,594
9	Coal Yard LED Lighting Replacement	141,819
10	Condenser Tubesheet Clad- Unit 7	124,016
11	Chemical Feed System- Unit 7	118,539
12	Absorber Recirculating- Unit 8	99,811
13	3 Pulverizer Refurbishment- Unit 8	93,302
14	Conveyor A Chute Replacement	91,959
15	Chemical Feed System Blr FW- Unit 8	71,362
16	Replace N Hotleg Joint- Unit 8	57,075
17	Minor Projects	56,215
18		
19	PRODUCTION - Killen (*)	
20	Gypsum Stack-Out Pad	666,363
21	Ivara Software For Asset Management	646,750
22	Boiler Plant Equipment	238,404
23	Air Heater Baskets	165,089
24	Turbogenerator Units	65,019
25	Accessory Elec Equipment	65,019
26	Misc Plant Equipment	65,019
27	Turbine Deck Fire Protection	40,053
28	Makeup Water To Humidification	25,356
29	Minor Projects	4,791
30		
31	PRODUCTION - Conesville (*)	
32	FGD Landfill	566,572
33	Fan Assemby Replacement	311,964
34	Fan Rotating Blade Rep	216,947
35	FGD Serv Water Well System	72,726
36	Ash Water Pump Assembly Purchase	42,276
37	Fan Hydraulic Cylinder Rebuild	36,056
38	Winterization Heater	33,732
39	Coal Mill Grind Zone Overhaul	26,282
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Dynegy and/or	
42	AEP.	
43	TOTAL	78,020,708

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	PRODUCTION - Conesville (*) (Cont'd)	
2	Reclaim Dust Collector Enclosure Install	24,809
3	Coal Transfer Hose Heating System Install	22,557
4	Conveyor Belt Replacement	18,836
5	Magnetic Separator Replacement	14,851
6	Pumps Fans and Blowers	10,348
7	Dissolved Oxygen Instrument Replacement	8,606
8	Generator Shaft GR Monitoring System Install	6,422
9	Valve Replacement	5,099
10	LS4 80 Level Switch Replacement	846
11		
12	PRODUCTION - Other	
13	Montpelier 4B Turbine claim	1,269,623
14	Responsible Diesel Generators RICE Emissions Compliance	1,090,443
15	Montpelier GG1A failure	518,540
16	Monument Diesel Reliability Upgrade	458,402
17	Sidney Units Controls Upgrade	457,693
18	Minor Projects	251,633
19		
20	DISTRIBUTION	
21	Distribution Pole Replacement Program	2,221,064
22	4KV Distribution Upgrade To 12KV	2,187,883
23	Indian Lake Substation 30MVA Transformer	2,157,461
24	Billed Distribution Projects	2,156,372
25	WPAFB Install Scada System	1,810,988
26	Planned Replace-Distribution	1,443,280
27	WPAFB: Cable Replacement	1,559,909
28	Southtown Substation 2nd 30 MVA Transformer (FUYAO)	1,090,042
29	Eaker Substation 69Kv/12Kv Transformer Failure (Distribution) Insurance Claim	1,077,268
30	Webster Substation BK-2 Transformer Failure	941,288
31	Cutout Capitalization Project	793,597
32	AC Network Automation	753,020
33	Spot Network 15Kv Vacuum Switches	672,992
34	Wilmington Substation Transformer Failure	570,717
35	Overhead Reliability Program	548,926
36	Crown Pilot Wire Project	499,577
37	Minor Projects	67,442
38		
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Dynegy and/or	
42	AEP.	
43	TOTAL	78,020,708

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	GENERAL	
2	Office Furniture and Equipment	4,777,381
3	US SBU Voice Over Internet Protocol Implementation-Dpl	1,108,563
4	CSS PIPP Enhancements	603,110
5	Supply Chain MDC Semi Tractor	438,425
6	Tools Shop And Garage Equipment	339,918
7	Communication Equipment	271,706
8	Network Infrastructure	219,531
9	GIS Database- AC Network	194,130
10	DP&L Physical Security Enhancements	163,153
11	CSS Guarantor Enhancements	153,559
12	US SBU Network Integration-Dpl	141,781
13	CSS Tariff Modeler Technology Upgrade	131,752
14	TransOp Computer Virualization	118,052
15	DP&L Web Portal For Customer Self- Service Phase 1	111,805
16	GIS Database Expansion- New Landbase & Conflation	108,222
17	Greenville Pole Yard	92,180
18	Minor Projects	40,616
19		
20	TRANSMISSION	
21	69 KV Hutchings Relays	1,819,812
22	PJM Rtep- Shelby To Sidney Rcnd- Circuit 13826	1,587,800
23	Transportation Equipment	806,354
24	PJM Rtep- West Milton- Salem- Englewood Rcnd	744,669
25	CCD Trans-Csp Da-33 1/3%	581,608
26	Waynesville Substation Steel Structures	500,624
27	Elec Planned R/P-Transmis	443,913
28	PJM Rtep - 345/69kV Marysville Substation	403,158
29	PJM Rtep- New West Milton-Eldean 138KV Circuit	359,348
30	Digital Fault Recorder Upgrades	353,737
31	PJM Rtep- Bath To Trebein Rcnd-Circuit 13810	291,181
32	CD Trans-CG&E DA-50%/50%	283,887
33	Forced Repair - Transmission Substations	221,961
34	CCD Trans-CG&E DA-28%/36%/36%	143,462
35	Minor Projects	10,655
36		
37	UNALLOCATED CONSTRUCTION OVERHEADS	-1,302,314
38		
39		
40		
41		
42		
43	TOTAL	78,020,708

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	-2,551,922,224	-2,551,922,224		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	-125,172,199	-125,172,199		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-2,700,796	-2,700,796		
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)	-127,872,995	-127,872,995		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	-18,481,376	-18,481,376		
13	Cost of Removal	-8,958,431	-8,958,431		
14	Salvage (Credit)	-445,548	-445,548		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	-26,994,259	-26,994,259		
16	Other Debit or Cr. Items (Describe, details in footnote):	-113,091,951	-113,091,951		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	-2,765,892,911	-2,765,892,911		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	-1,643,081,667	-1,643,081,667		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	-75,758,692	-75,758,692		
25	Transmission	-240,976,450	-240,976,450		
26	Distribution	-782,190,030	-782,190,030		
27	Regional Transmission and Market Operation				
28	General	-23,886,072	-23,886,072		
29	TOTAL (Enter Total of lines 20 thru 28)	-2,765,892,911	-2,765,892,911		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) _ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

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

1. Generation impairments to reserve	$(112,919,546)
2. Retirement solar PPE offset	(55,572)
3. Intangible adjustments	(116,833)
	$(113,091,951)

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				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

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 form investments, including such revenues form 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
				2
				3
				4
				5
				6
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				9
				10
				11
				12
				13
				14
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MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	63,612,344	70,381,548	All
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	12,537,842	10,289,014	All
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	27,770,400	28,921,160	Electric
8	Transmission Plant (Estimated)	2,938	35,788	Electric
9	Distribution Plant (Estimated)	1,359,362	1,297,012	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)	41,670,542	40,542,974	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1,431,448	2,052,045	All
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	106,714,334	112,976,567	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	30,238.00	3,250		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	113,590.00		117,162.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:	2,950.00	886		
9		-37,592.00	-1,169		
10	Prior Period Adjustment	2,083.00			
11					
12					
13					
14					
15	Total	-32,559.00	-283		
16					
17	Relinquished During Year:				
18	Charges to Account 509	30,670.00	615		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	80,599.00	2,352	117,162.00	
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/transferors 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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						30,238.00	3,250	1
								2
								3
67,087.00		67,087.00		1,811,349.00		2,176,275.00		4
								5
								6
								7
						2,950.00	886	8
						-37,592.00	-1,169	9
						2,083.00		10
								11
								12
								13
								14
						-32,559.00	-283	15
								16
								17
						30,670.00	615	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
67,087.00		67,087.00		1,811,349.00		2,143,284.00	2,352	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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 No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	993.00	2,306		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	17,021.00		21,329.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	16,773.00	2,306		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,241.00		21,329.00	
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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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/transferors 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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						993.00	2,306	1
								2
								3
						38,350.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						16,773.00	2,306	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
						22,570.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
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								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

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

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	No Quarter 4 Activity				
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 Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unrealized Loss - Pension and Retiree	99,647,015	2,234,714	410.1, 926	10,250,050	91,631,679
2	Deferred Recoverable Income Taxes	43,068,788	6,107,785	282, 283	12,782,084	36,394,489
3	Fuel Deferral	16,262,538	44,308,548	Various	46,709,229	13,861,857
4	Fuel Deferral - Unbilled		12,689,265			12,689,265
5	Unrecovered OVEC Charges		10,461,163			10,461,163
6	Smart Grid & Advanced Metering Infrastructure Costs	6,635,263	12,667,714	421	12,036,419	7,266,558
7	Generation Separation Costs	1,593,926	2,928,871	Various	671,959	3,850,838
8	Consumer Education Campaign	3,038,792				3,038,792
9	Retail Settlement System Costs	3,067,358				3,067,358
10	Rate Case Expense - Distribution Filing	425,284	3,664,084		2,142,459	1,946,909
11	Economic Development Costs	2,111,348	8,432,578	421, 456	10,053,982	489,944
12	Energy Efficiency Program	1,737,648		421, 580	1,737,648	
13	Deferred Windstorm Costs	22,300,000		593	22,300,000	
14	Reconciliation Rider	772,485		501, 555	772,485	
15	Other Regulatory Assets	1,096,319	3,254,851	Various	3,715,349	635,821
16						
17						
18						
19						
20						
21						
22						
23						
24						
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42						
43						
44	TOTAL	201,756,764	106,749,573		123,171,664	185,334,673

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 15 Column: f

“This footnote pertains to Page 232, Lines 1 through 15. See Footnote 3 on Notes to the Financial Statements for descriptions of Regulatory Assets”.

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	Balance at Beginning of Year	Debits	CREDITS		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Property Taxes (1)	75,446,941	79,754,999	408.1	76,041,130	79,160,810
2						
3	Trust Assets	9,596,936	4,218,706	131, 228	5,354,565	8,461,077
4						
5	Refundable Tax Benefit from					
6	Contrib. in Aid of Const. (2)	90,227		456	23,286	66,941
7						
8	Payroll Advances	36,328	1,141,721	Various	1,197,277	-19,228
9						
10	Other	1,022,525	14,810,970	Various	14,946,860	886,635
11						
12						
13						
14						
15						
16	(1) Amortized over 12 months					
17	(2) Amortized through 2018					
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	1,523,771				1,923,727
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	87,716,728				90,479,962

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 Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Federal Deferred Tax on Future Tax Impacts	941,184	942,842
3	Union Disability	5,094,099	4,107,507
4	Post Retirement Benefits	8,379,691	8,069,370
5	Deferred Compensation	1,086,049	1,226,722
6	FAS 109 - Electric	-5,161,103	-612,840
7	Other	2,691,852	2,093,078
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,031,772	15,826,679
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	27,200	27,200
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	13,058,972	15,853,879

Notes

		Beginning Balance	Ending Balance
(1)	L. 7, Col. b&c, Other		
	FERC Federal	19,108	13,949
	Vacation Accrual	837,673	1,032,831
	Book Capitalization of Construction Period Net Earnings	68,235	56,883
	State Income Taxes	2,815,628	2,718,275
	Employee Stock Options	991,226	935,508
	Bad Debt Exp	(209,434)	292,177
	ESOP	0	0
	Insurance Claims Reserve	(1,611,817)	(1,611,817)
	Accrued Employee Taxes	(2,467,214)	(3,255,699)
	Ohio Kwh Tax Accrual	0	0
	Capitalized Interest Income	2,249,848	1,900,207
	Deferred Interest on Future Tax Impacts	(8,988)	(13,642)
	Federal Deferred Tax on Non-Deductible State Tax	15,443	15,443
	Deferred Litigation Costs	(16,819)	0
	Other	8,962	8,962
(2)	L. 17, Col. b&c, Other		
	FAS 109 - Non utility	0	0
	Other	27,200	27,200

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	Common Stock	50,000,000	0.01	
2	--			
3	Total Common Stock	50,000,000		
4	--			
5				
6	--			
7	Preferred Stock			
8	--			
9	Issued			
10	3.75% SERIES A Cumulative		100.00	102.50
11	3.75% SERIES B Cumulative		100.00	103.00
12	3.90% SERIES C Cumulative		100.00	101.00
13	--			
14	Preferred Stock	4,000,000	100.00	
15				
16				
17				
18	--			
19	Unissued Preferred Stock	4,000,000	25.00	
20	--			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
41,172,173	411,722					1
						2
41,172,173	411,722					3
						4
						5
						6
						7
						8
						9
93,280	9,328,000					10
69,398	6,939,800					11
65,830	6,583,000					12
						13
228,508	22,850,800					14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
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						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	
2		
3	Account 209 - Reduction in Par Value of Capital Stock	
4		
5	Balance at Beginning of Year	287,793,490
6		
7	Subtotal 209 - Balance at End of Year	287,793,490
8		
9	Acct 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
10		
11	Balance at Beginning of Year	-822,811
12	Exp - Pref Stock Series A (INC)	
13	Exp - Pref Stock Series B (INC)	
14	Exp - Pref Stock Series C (INC)	
15	Exp - Pref Stock Series D (INC)	
16	Exp - Pref Stock Series H (INC)	15,649
17	Exp - Pref Stock Series I (INC)	17,334
18	Exp - Pref Stock Series E (INC)	20,243
19	Exp - Pref Stock Series J (INC)	85,550
20	Exp - Pref Stock Series F (INC)	23,114
21	Amortization of Preferred Stock	
22	Subtotal 210 - Balance at End of Year	-660,921
23		
24	Account 211 - Miscellaneous Paid-In Capital	
25		
26	Balance at Beginning of Year	229,259,019
27	Other Paid-In Capital from Parent	
28	Other Paid-In Capital Related to Equity Awards	-3,154
29	Other Paid-In Capital - Other	
30		
31	Subtotal 211 - Balance at End of Year	229,255,865
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	516,388,434

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	Common Stock - $.01 Par Value	16,716,891
2	---	
3		
4	Preferred Stock - $100 Par Value and $25 Par Value	
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	16,716,891

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		
2			
3	First Mortgage Bonds, Series:		
4			
5	1.875% due 2016 (PUCO Case #13-0893-EL-AIS dated 7/10/13)	445,000,000	7,430,582
6	1.875% due 2016 (PUCO Case #13-0893-EL-AIS dated 6/28/03) (D)		756,500
7	Bank Rate Tax Exempt, Series A (PUCO Case #15-634-EL-AIS dated 10/2/2015)	100,000,000	3,274,078
8	Bank Rate Tax Exempt, Series B (PUCO Case #15-634-EL-AIS dated 10/2/2015)	100,000,000	
9	4.8% due 2036, Series A (PUCO Case #06-758-EL-AIS dated 7/26/06)	100,000,000	1,781,846
10			
11			
12			
13	Guaranty of Air Quality Development		
14	Obligation, Series:		
15			
16			
17	Subtotal Account 221 - Bonds	745,000,000	13,243,006
18			
19	Account 222 - Reacquired Bonds		
20			
21	Account 223 - Advances From Associated Companies		
22			
23	Account 224 - Other Long-Term Debt		
24	4.2% - due 2061, Wright-Patterson Air Force Base	18,691,000	
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	763,691,000	13,243,006

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 Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
09/16	09/16	9/20/13	9/15/16	445,000,000		5
						6
08/15	08/20	8/03/15	7/31/20	100,000,000		7
08/15	08/20	8/03/15	7/31/20	100,000,000		8
09/06	09/36	9/13/06	8/31/36	100,000,000		9
						10
						11
						12
						13
						14
						15
						16
				745,000,000		17
						18
						19
						20
						21
						22
						23
03/11	03/61	3/01/11	2/28/61	18,103,259		24
						25
						26
						27
						28
						29
						30
						31
						32
				763,103,259		33

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 7 Column: a

Issued as security of $200,000,000 principal amount of Ohio Air Quality Development Authority (Air Bonds Series A $100M and Air Bonds Series B $100M) due 2020.

Schedule Page: 256 Line No.: 8 Column: a

See footnote on 256, Line 7, Column a

Schedule Page: 256 Line No.: 9 Column: a

Issued as security of $100,000,000 principal amount of Ohio Air Quality Development Authority Bonds, 4.8% due 2036.

Schedule Page: 256 Line No.: 24 Column: a

Issued $18,691,000 due March 2061 to finance the acquisition of Wright-Patterson Air Force Base electric transmission and distribution assets from the federal government.

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	106,439,866
2		
3		
4	Taxable Income Not Reported on Books	
5	Capitalized Interest	703,178
6	Contributions in Aid of Construction	1,275,052
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax Expense	34,846,162
11	Compensation and Benefits	7,811,273
12	Depreciation	18,310,629
13	Other	3,782
14	Income Recorded on Books Not Included in Return	
15	Unrealized Gains on Derivatives	-5,594,800
16	Allowance for Funds Used During Construction	2,010,791
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Dividends Received Deduction	161,997
21	Domestic Production Deduction	17,561,116
22	Regulatory Deferrals	-21,669,163
23	Capitalized Software	1,000,000
24		
25		
26		
27	Federal Tax Net Income	175,920,002
28	Show Computation of Tax:	
29	Ordinary Income at 35%	61,572,001
30	Adjusted Gross Federal Income Tax	61,572,001
31	Plus: Adjustments to Prior Year Accruals (Net)	-5,723,778
32		
33	TOTAL Federal Income Tax Payable (1)	55,848,223
34		
35		
36		
37		
38	(1) See Page 263-1 for Distribution.	
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 13 Column: a

OTHER:

Amortization of Reacquired Bonds	987,079
Accrued Claims	(1,750,153)
Net Miscellaneous	1,345,782
Bad Debts	(62,592)
Non-Deductible State Taxes	(516,334)
TOTAL OTHER	3,782

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

-

Statement Regarding Consolidated Group

Assignment of Tax to Consolidated Group Members:

The Respondent is a wholly owned subsidiary of DPL Inc., and is included in the consolidated Federal Income Tax Return of The AES Corporation, its ultimate parent. Taxes are allocated to members on the basis of separate returns.

Members of the DPL Inc. Consolidated Group:

Common Parent Corporation:	The AES Corporation
Subsidiary Corporations or L.L.C.s of The AES Corporation:	AES DPL Holdings, LLC
	Diamond Development, Inc.
	DPL Capital Trust II
	DPL Energy, LLC
	DPL Energy Resources, Inc.
	DPL Inc.
	MacGregor Park, Inc.
	MC Squared Energy Services, LLC
	Miami Valley Insurance Company
	Miami Valley Lighting, LLC
	The Dayton Power and Light Company

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 know, 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 Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	LOCAL - OHIO					
2	PROPERTY 2014/2013	71,842,852		676,287	72,519,138	
3	2015/2014			-57,932		75,436,499
4	2015/2014	75,436,400				-75,436,499
5	2016/2015			79,147,392		
6						
7	CITY INC 2014	813,300		1,080,905		
8	2014		1,134,307	-293,444	1,075,106	
9						
10	LOCAL - KENTUCKY					
11	PROPERTY 2005	147,357		-147,357		
12	2006	130,971		80,234	211,205	
13	2007	185,936		72,725	258,661	
14	2008	29,032		183,738	212,770	
15	2009	178,811		68,554	247,365	
16	2010	116,538		67,195	183,733	
17	2011	184,526		79,258	263,784	
18	2012	200,201		108,249	308,450	
19	2013	53,448		-15,936	11,648	
20	2014	7,389				
21	2015			9,552		
22						
23	STATE - OHIO					
24	FRANCHISE 2015					
25						
26	KWH EXCISE 2014	4,287,163			4,287,163	
27	2015			50,190,474	46,298,273	
28						
29	KWH EXCISE - UNBILLED					
30	2014	2,906,202		-2,906,202		
31	2015			2,634,825		
32						
33	MTCE OF PUCO 2015			1,556,958	1,556,958	
34						
35	MTCE OF OCC 2015			267,149	267,149	
36						
37	UNEMPL INSUR 2015			33,953	33,953	
38						
39	USE 2014	97,452		889,458	97,452	
40	2015			1,745,541	1,753,301	
41	TOTAL	161,009,477	1,368,890	204,812,534	198,806,888	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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 know, 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 Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	CAT 2014	760,470		141,179	901,649	
2	2015			3,017,568	2,231,616	
3						
4	USER FEES 2015			1,500	1,500	
5						
6	MISC INS PREMIUM TAX					
7	2015			36,397	36,397	
8						
9	STATE - KENTUCKY					
10	PROPERTY 2005					
11	2006	199,022		-56,954	142,068	
12	2007	102,883		65,134	168,017	
13	2008	84,008		47,584	131,592	
14	2009	239,905		-89,702	150,203	
15	2010	234,386		-102,708	131,678	
16	2011	253,124		-108,320	144,804	
17	2012	259,864		-97,467	162,134	
18	2013	24,085				
19	2014	3,152				
20	2015			3,864		
21						
22	INCOME 2015	33,624		3,267		
23	2015		185,146	56,872		
24						
25	STATE - PENNSYLVANIA					
26	NON-OH FRANCHISE 2015		49,437	1,203	-15,000	
27						
28	UNEMPLOY INS 2015					
29						
30	STATE - INDIANA					
31	UNEMPLOY INS 2015					
32						
33	FEDERAL					
34	UNEMPLOY INS 2015			53,841	53,841	
35						
36	INS CONTRIB 2015			7,174,789	7,174,789	
37	2015					
38						
39	HEAVY VEHICLE USE					
40	2015			3,390	3,390	
41	TOTAL	161,009,477	1,368,890	204,812,534	198,806,888	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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 know, 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 Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	INCOME 2015	2,974,088				
2						
3	ACCR FED INC 2015			-2,386,079	-2,386,079	
4	2015	-776,712		61,575,600	60,188,180	
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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35						
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37						
38						
39						
40						
41	TOTAL	161,009,477	1,368,890	204,812,534	198,806,888	

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 (I) 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
		676,287				2
75,378,468		75,377,038			-75,434,970	3
						4
79,147,392					79,147,392	5
						6
1,894,205		1,080,863			42	7
	2,502,857	-293,444				8
						9
						10
		-147,357				11
		80,234				12
		72,725				13
		183,738				14
		68,554				15
		67,195				16
		79,258				17
		108,249				18
25,864		-15,936				19
7,389		7,389			-7,389	20
9,552					9,552	21
						22
						23
						24
						25
						26
3,892,201		50,190,474				27
						28
						29
		-2,906,202				30
2,634,825		2,634,825				31
						32
					1,556,958	33
						34
					267,149	35
						36
		23,869			10,084	37
						38
889,458					889,458	39
-7,760					1,745,541	40
168,310,598	2,664,365	195,312,996			9,499,539	41

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 (I) 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)	
		141,179				1
785,952		3,141,726			-124,158	2
						3
		1,500				4
						5
						6
		36,397				7
						8
						9
						10
		-56,954				11
		65,134				12
		47,584				13
		-89,702				14
		-102,708				15
		-108,320				16
264		-283,473			186,007	17
24,085						18
3,152						19
3,864					3,864	20
						21
36,891		3,267				22
	128,274	56,872				23
						24
						25
	33,234	1,203				26
						27
						28
						29
						30
						31
						32
						33
		119,367			-65,526	34
						35
		5,862,855			1,311,934	36
						37
						38
						39
		3,390				40
168,310,598	2,664,365	195,312,996			9,499,539	41

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 (I) 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)	
2,974,088						1
						2
						3
610,708		-2,386,079				4
		61,571,999			3,601	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						32
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						35
						36
						37
						38
						39
						40
168,310,598	2,664,365	195,312,996			9,499,539	41

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

(1) Taxes included with costs charged to other accounts. The amounts for motor vehicle fuel taxes and vehicle license fees are not known.

(2) Apportionment Basis to Utility Department and Other Accounts

Kind of Tax	Apportionment Basis
Local – Ohio	
Property	Assessed property taxable values
City Income	Taxable income
State – Ohio	
KWH Excise	Tax on electrical use
CAT	Tax on gross receipts
Maintenance of PUCO	Intrastate (Ohio) gross revenues
Maintenance of OCC	Intrastate (Ohio) gross revenues
Fuel Use	Use of equipment
Unemployment Insurance	Annualized payroll
State – Kentucky	
Property	Assessed property taxable values
State Income	Taxable income
State – Pennsylvania	
Unemployment Insurance	Annualized payroll
State Income	Taxable income
State – Indiana	
Unemployment Insurance	Annualized payroll
Federal	
Unemployment Insurance	Annualized payroll
Insurance Contributions	Annualized payroll
Heavy Vehicle Use	Use of equipment
Income	Taxable income

Schedule Page: 262 Line No.: 4 Column: l

Account 1860006

Schedule Page: 262 Line No.: 7 Column: l

Account 2113000

Schedule Page: 262 Line No.: 18 Column: l

Account 1860012

Schedule Page: 262 Line No.: 19 Column: l

See footnote on 262, Line 18, Column l

Schedule Page: 262 Line No.: 24 Column: l

Account 1310211

Schedule Page: 262 Line No.: 37 Column: l

Account 107, 408

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 40 Column: l
Account 9200000

Schedule Page: 262.1 Line No.: 2 Column: l
Account 4190000, 1460123

Schedule Page: 262.1 Line No.: 17 Column: l
See footnote on 262, Line 18, Column l

Schedule Page: 262.1 Line No.: 18 Column: l
See footnote on 262, Line 18, Column l

Schedule Page: 262.1 Line No.: 19 Column: l
See footnote on 262, Line 18, Column l

Schedule Page: 262.1 Line No.: 22 Column: l
Account 1420001, 1310211

Schedule Page: 262.1 Line No.: 26 Column: l
Account 1310101

Schedule Page: 262.1 Line No.: 31 Column: l
Account 232

Schedule Page: 262.1 Line No.: 34 Column: l
See footnote on 262, Line 31, Column l

Schedule Page: 262.1 Line No.: 37 Column: l
See footnote on 262, Line 31, Column l

Schedule Page: 262.2 Line No.: 1 Column: l
Account 1432000

Schedule Page: 262.2 Line No.: 5 Column: l
See footnote on 262, Line 7, Column l

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%	91,367			411.4	9,772	
4	7%	187			411.4	20	
5	10%	22,281,175	411.4		411.4	2,383,034	
6							
7							
8	TOTAL	22,372,729				2,392,826	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Non-Utility 10%						
11							
12	TOTAL NON-UTILITY						
13							
14							
15		22,372,729				2,392,826	
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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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
81,595			3
167			4
19,898,141			5
			6
	39 Years		7
19,979,903			8
			9
			10
			11
			12
			13
			14
19,979,903			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
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			47
			48

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Tax Benefits Refundable	90,227	232	23,286		66,941
2						
3	Long Term Liability -	1,729,933	Various	2,325,137	595,204	
4	PUCO Stipulation Payments					
5						
6	Miscellaneous	46,330	Various	46,448	118	
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
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42						
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44						
45						
46						
47	TOTAL	1,866,490		2,394,871	595,322	66,941

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

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

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

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	629,693,973	-13,492,941	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	629,693,973	-13,492,941	
6	Total Non-Utility	-6,384,333	-446,268	
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	623,309,640	-13,939,209	
10	Classification of TOTAL			
11	Federal Income Tax	616,392,205	-13,366,552	
12	State Income Tax	935,230	-72,823	
13	Local Income Tax	5,982,205	-499,834	

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
				182, 190	1,846,087	618,047,119	2
							3
							4
					1,846,087	618,047,119	5
						-6,830,601	6
							7
							8
					1,846,087	611,216,518	9
							10
					1,833,525	604,859,178	11
					12,200	874,607	12
					362	5,482,733	13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 274   Line No.: 2   Column: j

Balance sheet adjustments to comply with ASC 740.

ACCUMULATED DEFFERED 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	Capitalized Software	4,123,896	264,634	
4	Reacquisition of Bonds	3,479,404	-345,478	
5	Pensions	34,091,805	-3,106,336	
6	Phase-In Deferral	17,969,290	-6,461,879	
7	FAS 109 - Electric	13,210,735		
8	Other	-670,036	231,491	
9	TOTAL Electric (Total of lines 3 thru 8)	72,205,094	-9,417,568	
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 11 thru 16)			
18	TOTAL Steam and Non-Utility	-32,869,499	-1,958,180	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	39,335,595	-11,375,748	
20	Classification of TOTAL			
21	Federal Income Tax	39,335,595	-11,375,748	
22	State Income Tax			
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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						4,388,530	3
						3,133,926	4
						30,985,469	5
						11,507,411	6
		182	987,283	182		12,223,452	7
						-438,545	8
			987,283			61,800,243	9
							10
							11
							12
							13
							14
							15
							16
							17
		190, 219	108,260	190, 219	9,012,249	-25,923,690	18
			1,095,543		9,012,249	35,876,553	19
							20
			1,095,543		9,012,249	35,876,553	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: a

This footnote pertains to p. 276 and p. 277, line 8.

ITEM	BALANCE AT BEGINNING OF YEAR	CHANGES DURING YEAR AMOUNTS DEBITED TO ACCT. 410.1 (X993)	CHANGES DURING YEAR AMOUNTS CREDITED TO ACCT. 411.1 (X994)	BALANCE AT END OF YEAR
Incentive Bonus	(1,499,789)	(63,002)	0	(1,562,791)
Misc Other Timing Issues	1,325,062	(200,816)	0	1,124,246
Book Def – EPA Costs	(495,309)	495,309	0	0

Schedule Page: 276 Line No.: 9 Column: j

Balance sheet adjustment to comply with ASC 740.

Schedule Page: 276 Line No.: 19 Column: h

Deferred tax adjustment related to OCI.

Schedule Page: 276 Line No.: 19 Column: j

See footnote on 276, Line 19, Column h

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Competitive Bidding	744,079	0	20,341,131	28,724,716	9,127,664
2	Energy Efficiency Program		Various	32,812,227	42,041,105	9,228,878
3	Pension Benefits	4,820,252	219, 228.3	720,786	1,037,659	5,137,125
4	Transmission Costs	2,939,980	421, 555	177,085,751	177,884,861	3,739,090
5	Reconciliation Rider		501, 555	8,542,216	10,627,119	2,084,903
6	Other Regulatory Liabilities	726,073	Various	5,496,594	5,020,176	249,655
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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27						
28						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	9,230,384		244,998,705	265,335,636	29,567,315

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 278   Line No.: 6   Column: f

"This footnote pertains to Page 278, Lines 1 through 6. See Footnote 3 on Notes to the Financial Statements for descriptions of Regulatory Liabilities".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

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	490,851,567	524,917,824
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	189,376,606	195,720,217
5	Large (or Ind.) (See Instr. 4)	85,639,055	90,208,462
6	(444) Public Street and Highway Lighting	1,284,213	1,103,834
7	(445) Other Sales to Public Authorities	58,007,558	55,754,674
8	(446) Sales to Railroads and Railways	394,538	462,561
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	825,553,537	868,167,572
11	(447) Sales for Resale	693,043,931	835,266,309
12	TOTAL Sales of Electricity	1,518,597,468	1,703,433,881
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,518,597,468	1,703,433,881
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,146,361	3,126,037
17	(451) Miscellaneous Service Revenues	822,398	827,562
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	957,309	1,332,363
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	6,067,386	10,314,653
22	(456.1) Revenues from Transmission of Electricity of Others	54,716,237	67,364,383
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	65,709,691	82,964,998
27	TOTAL Electric Operating Revenues	1,584,307,159	1,786,398,879

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
2,726,730	2,811,931	254,349	256,671	2
				3
637,186	671,662	21,691	21,987	4
80,338	82,717	448	483	5
3,786	4,138	403	458	6
453,458	441,377	794	873	7
3,546	3,706	1	1	8
				9
3,905,044	4,015,531	277,686	280,473	10
12,527,992	14,627,664	4	16	11
16,433,036	18,643,195	277,690	280,489	12
				13
16,433,036	18,643,195	277,690	280,489	14

Line 12, column (b) includes $ -5,755,692 of unbilled revenues.
Line 12, column (d) includes -118,286 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 10 Column: d

Total Sales to Ultimate Consumers reflects MWH that are consumed by customers that buy transmission, distribution and generation services from DP&L.

Schedule Page: 300 Line No.: 10 Column: f

Total Sales to Ultimate Consumers reflects customers that bought transmission, distribution and generation services from DP&L.

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

Other Electric Revenues includes the following amounts:

Revenues from Non-Taxable Sales, Switching and Billing service revenues and gains/losses from the sale of coal.

Schedule Page: 300 Line No.: 22 Column: c

Revenue from Transmission of Electricity of Others includes the following amounts:

Transmission of Others Electricity, RTO revenues including Transmission Congestion, Losses, Firm and Non-Firm Point-to-Point, Network Integration, Transmission Service, Transmission Owner Scheduling, FTR Auction Revenues and Expansion Coal Recovery Credits.

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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	440 Residential Sales					
2						
3	Private Outdoor Lighting Service	6,802	1,704,915			0.2506
4	Residential Service	1,722,840	329,709,379	187,704	9,178	0.1914
5	Secondary Service	6,417	780,543	657	9,767	0.1216
6	Residential Electric Heating Serv	1,015,496	163,893,608	65,987	15,389	0.1614
7	Unbilled and Other	-24,824	-5,236,878			0.2110
8						
9	Total Residential Sales	2,726,731	490,851,567	254,348	10,720	0.1800
10						
11	442 Commercial and Industrial					
12						
13	Sales - Commercial Sales					
14	Private Outdoor Lighting Service	6,851	1,818,669			0.2655
15	Residential Service	17,143	3,690,712	749	22,888	0.2153
16	Secondary Service	580,379	164,660,476	20,921	27,741	0.2837
17	High Voltage Serv (with demand)	163	75,503	1	163,000	0.4632
18	School		155,364			
19	Primary Service	33,074	17,739,253	17	1,945,529	0.5364
20	Street Lighting	4	1,362,513	3	1,333	340.6283
21	Unbilled and Other	-428	-125,884			0.2941
22						
23	Total Commercial Sales	637,186	189,376,606	21,691	29,376	0.2972
24						
25	Sales - Industrial Sales					
26	Private Outdoor Lighting Service	614	16,277,559			26.5107
27	Secondary Service	50,450	11,381,099	428	117,874	0.2256
28	Primary Service	16,911	6,324,393	20	845,550	0.3740
29	Primary Substation Service	10,489	40,083,815	1	10,489,000	3.8215
30	High Voltage Service		11,958,467			
31	Special Contracts		2,349			
32	Unbilled and Other	1,871	-388,627			-0.2077
33						
34	Total Industrial Sales	80,335	85,639,055	449	178,920	1.0660
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,023,330	831,309,229	277,686	14,489	0.2066
42	Total Unbilled Rev.(See Instr. 6)	-118,286	-5,755,692	0	0	0.0487
43	TOTAL	3,905,044	825,553,537	277,686	14,063	0.2114

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	444 Pub Street & Highway Lighting					
2						
3	Private Outdoor Lighting Service	402	68,494			0.1704
4	Secondary Service	2,050	1,030,346	384	5,339	0.5026
5	Primary Service		75,517			
6	Street Lighting Service	1,310	99,834	20	65,500	0.0762
7	Unbilled and Other	24	10,021			0.4175
8						
9	Total Pub St & Highway Lighting	3,786	1,284,212	404	9,371	0.3392
10						
11	445 Oth Sales to Pub Auth					
12						
13	Private Outdoor Lighting Service	440	192,124			0.4366
14	Residential Service	129	26,667	12	10,750	0.2067
15	Secondary Service	25,442	21,691,703	777	32,744	0.8526
16	Residential Electric Heating Serv	24	8,876	2	12,000	0.3698
17	Street Lighting Service					
18	School	23	2,155,876	2	11,500	93.7337
19	Primary Service	151	5,929,115	1	151,000	39.2657
20	High Voltage Service	7,128	1,706,411			0.2394
21	Special Contracts	419,976	26,264,617	1	419,976,000	0.0625
22	Unbilled and Other	145	32,168			0.2218
23						
24	Total Oth Sales to Pub Auth	453,458	58,007,557	795	570,387	0.1279
25						
26	446 Sales to Railroads & Railways					
27						
28	Primary Service	3,885				
29	Unbilled and Other	-339				
30						
31	Total Sales to Railrds & Railways	3,546				
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,023,330	831,309,229	277,686	14,489	0.2066
42	Total Unbilled Rev.(See Instr. 6)	-118,286	-5,755,692	0	0	0.0487
43	TOTAL	3,905,044	825,553,537	277,686	14,063	0.2114

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	DPL Energy Resources	RQ	Vol. 6	N/A	N/A	N/A
2	DPL Energy Resources & MC2 Energy Serv	RQ	Vol. 6	N/A	N/A	N/A
3	American Electric Power (AEP)	RQ	Vol. 10	N/A	N/A	N/A
4	Duke Energy Ohio	RQ	Vol. 10	N/A	N/A	N/A
5	First Energy Co.	RQ	Vol. 10	N/A	N/A	N/A
6	Village of Georgetown	RQ	Vol. 10	N/A	N/A	N/A
7	Arcanum	OS	42	N/A	N/A	N/A
8	Eldorado	OS	49	N/A	N/A	N/A
9	Jackson Center	OS	43	N/A	N/A	N/A
10	Lakeview	OS	44	N/A	N/A	N/A
11	Mendon	OS	45	N/A	N/A	N/A
12	Minster	OS	50	N/A	N/A	N/A
13	New Bremen	OS	46	N/A	N/A	N/A
14	Tipp City	OS	51	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Versailles	OS	52	N/A	N/A	N/A
2	Waynesfield	OS	47	N/A	N/A	N/A
3	Yellow Springs	OS	53	N/A	N/A	N/A
4	Piqua	OS	41	N/A	N/A	N/A
5	Midwest Independent Trans Sys Operators	OS	Vol. 10/Attach W	N/A	N/A	N/A
6	New York Independent Sys Operators	OS	Vol. 10	N/A	N/A	N/A
7	Potomac Electric Power-PJM	OS	Vol. 6	N/A	N/A	N/A
8	DTE Energy Trading	OS	N/A	N/A	N/A	N/A
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3,951,850		199,611,457		199,611,457	1
1,976,497		105,384,810		105,384,810	2
575,138		30,468,308		30,468,308	3
					4
497,168		30,837,063		30,837,063	5
46,799		3,100,223		3,100,223	6
					7
					8
					9
					10
					11
					12
					13
					14
7,047,452	0	369,401,861	0	369,401,861	
5,480,540	63,000	323,579,070	0	323,642,070	
12,527,992	**63,000**	**692,980,931**	**0**	**693,043,931**	

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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
					4
		53		53	5
					6
5,480,540		323,579,017		323,579,017	7
	63,000			63,000	8
					9
					10
					11
					12
					13
					14
7,047,452	0	369,401,861	0	369,401,861	
5,480,540	63,000	323,579,070	0	323,642,070	
12,527,992	**63,000**	**692,980,931**	**0**	**693,043,931**	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

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

DPL Energy Resources is a subsidiary of DPL Inc.

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

DP&L sold a total 9,716,793 mwh to DPL Energy Resources, a Certified Retail Energy Resouce (CRER) provider to the DP&L service territory.

Schedule Page: 310 Line No.: 2 Column: g

The 4,067,470 reported as wholesale to DPL Energy Resources and MC Squared Services, affiliated companies are related to off-system sales in Ohio and Illinois.

Schedule Page: 310 Line No.: 7 Column: b

This footnote pertains to Page 310, Lines 7-14, Column b; Page 310.1, Lines 1-4, Column b.

Services provided to these customers may include firm power, short term power, firm transmission, short term transmission, non-displacement, emergency and regulation service.

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	8,246,499	3,579,259
5	(501) Fuel	252,631,592	329,815,018
6	(502) Steam Expenses	20,109,965	31,725,831
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	989,589	1,098,303
10	(506) Miscellaneous Steam Power Expenses	20,912,568	13,723,606
11	(507) Rents	13,979	-246
12	(509) Allowances	2,895	114,561
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	302,907,087	380,056,332
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,066,801	3,467,403
16	(511) Maintenance of Structures	10,301,689	7,151,695
17	(512) Maintenance of Boiler Plant	41,368,135	42,078,079
18	(513) Maintenance of Electric Plant	8,412,615	11,804,988
19	(514) Maintenance of Miscellaneous Steam Plant	12,790,749	6,841,999
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	74,939,989	71,344,164
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	377,847,076	451,400,496
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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		
63	(547) Fuel	2,705,505	1,302,059
64	(548) Generation Expenses	399,900	453,617
65	(549) Miscellaneous Other Power Generation Expenses	568,948	413,750
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,674,353	2,169,426
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	561,437	725,360
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	20,535	5,362
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	581,972	730,722
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	4,256,325	2,900,148
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	443,018,722	489,746,256
77	(556) System Control and Load Dispatching	3,079,803	3,907,456
78	(557) Other Expenses	346,339	1,099,933
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	446,444,864	494,753,645
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	828,548,265	949,054,289
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	428,710	644,266
84			
85	(561.1) Load Dispatch-Reliability	1,175,497	967,777
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,542	6,147
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	6,604,286	8,199,036
89	(561.5) Reliability, Planning and Standards Development	445,977	488,638
90	(561.6) Transmission Service Studies	-1,418	-11,009
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,472	2,143
94	(563) Overhead Lines Expenses	13,898	24,330
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	79,108,518	114,936,228
97	(566) Miscellaneous Transmission Expenses		
98	(567) Rents	871	87,493
99	TOTAL Operation (Enter Total of lines 83 thru 98)	87,786,353	125,345,049
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	13,351	25,401
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	38,359	58,359
104	(569.2) Maintenance of Computer Software	21,174	139,746
105	(569.3) Maintenance of Communication Equipment	205,283	248,937
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	62,491	582,372
108	(571) Maintenance of Overhead Lines	2,889,292	1,926,255
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,229,950	2,981,070
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	91,016,303	128,326,119

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		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,596,319	2,873,136
135	(581) Load Dispatching		
136	(582) Station Expenses	398,813	388,897
137	(583) Overhead Line Expenses	500,484	431,560
138	(584) Underground Line Expenses	971,913	685,635
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	37,981	29,725
141	(587) Customer Installations Expenses	616,803	598,535
142	(588) Miscellaneous Expenses	101,380	69,574
143	(589) Rents	9,798	3,237
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,233,491	5,080,299
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,635,262	2,234,279
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	4,187,508	3,787,940
149	(593) Maintenance of Overhead Lines	40,296,399	26,136,499
150	(594) Maintenance of Underground Lines	61,792	53,839
151	(595) Maintenance of Line Transformers	312,955	218,597
152	(596) Maintenance of Street Lighting and Signal Systems	618	161
153	(597) Maintenance of Meters	186,179	121,426
154	(598) Maintenance of Miscellaneous Distribution Plant	135,179	133,636
155	TOTAL Maintenance (Total of lines 146 thru 154)	47,815,892	32,686,377
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	53,049,383	37,766,676
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	3,850,036	3,514,344
161	(903) Customer Records and Collection Expenses	10,732,832	10,627,898
162	(904) Uncollectible Accounts	29,551,834	50,083,755
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	44,134,702	64,225,997

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	2,917,017	1,387,494
168	(908) Customer Assistance Expenses	6,408,321	3,940,926
169	(909) Informational and Instructional Expenses	2,153,877	2,034,663
170	(910) Miscellaneous Customer Service and Informational Expenses	17,277,242	15,501,151
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	28,756,457	22,864,234
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	5,990,084	-3,071,887
182	(921) Office Supplies and Expenses	25,360,748	28,340,682
183	(Less) (922) Administrative Expenses Transferred-Credit	2,841,878	1,814,270
184	(923) Outside Services Employed	11,597,889	13,451,385
185	(924) Property Insurance	3,899,097	1,689,739
186	(925) Injuries and Damages	2,557,322	2,633,469
187	(926) Employee Pensions and Benefits	21,048,121	20,110,013
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,854,107	2,030,000
190	(929) (Less) Duplicate Charges-Cr.	1,267,750	1,399,576
191	(930.1) General Advertising Expenses	1,039,762	689,338
192	(930.2) Miscellaneous General Expenses	1,868,060	6,930,566
193	(931) Rents	29,297	40,435
194	TOTAL Operation (Enter Total of lines 181 thru 193)	73,134,859	69,629,894
195	Maintenance		
196	(935) Maintenance of General Plant	1,732,995	1,755,041
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	74,867,854	71,384,935
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,120,372,964	1,273,622,250

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 181 Column: c

2014 amounts corrected due to reclassification of labor

Schedule Page: 320 Line No.: 182 Column: c

See footnote on 320, Line 181, Column c

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Brookfield Energy Marketing	OS		N/A	N/A	N/A
2	Calpine			N/A	N/A	N/A
3	DTE Energy Trading	OS		N/A	N/A	N/A
4	DPL Energy	OS		N/A	N/A	N/A
5	Exelon Generation	OS		N/A	N/A	N/A
6	First Energy Co.	OS		N/A	N/A	N/A
7	AEP	OS		N/A	N/A	N/A
8	Illinois Commerce Commission	OS		N/A	N/A	N/A
9	Karbone Inc.	OS		N/A	N/A	N/A
10	Midwest Ind Trans Sys Operator Inc	OS		N/A	N/A	N/A
11	NRG	OS		N/A	N/A	N/A
12	Ohio Valley Electric Corp.	OS	28	N/A	N/A	N/A
13	Pioneer Energy	OS		N/A	N/A	N/A
14	PJM Interconnection, LLC	OS		N/A	N/A	N/A
	Total					

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	3 Degrees Group Inc	OS		N/A	N/A	N/A
2	Brokerage Services	OS		N/A	N/A	N/A
3	Regulatory Deferrals	AD		N/A	N/A	N/A
4						
5						
6						
7						
8						
9						
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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
			942,930			942,930	1
			272,848			272,848	2
			154,800			154,800	3
40,513				1,992,157		1,992,157	4
1,095,046				65,394,389		65,394,389	5
161,795				7,984,149		7,984,149	6
1,135,427				70,515,827		70,515,827	7
					1,750,511	1,750,511	8
			61,291			61,291	9
				282		282	10
			25,258			25,258	11
540,527			15,614,500	15,574,549		31,189,049	12
							13
3,318,891			117,459,716	144,983,830		262,443,546	14
6,292,199			134,531,343	306,445,183	2,042,196	443,018,722	

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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)	
							1
					307,948	307,948	2
					-16,263	-16,263	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
6,292,199			134,531,343	306,445,183	2,042,196	443,018,722	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: l

Column l includes brokerage fees, renewable energy recs and compliance recs, and regulatory deferrals.

Brokerage Services breakdown:

Amerex Power	71,163
BGC	21,338
Choice	16,902
Evolution	1,152
ICAP	121,590
IVG	3,700
Intercontinental Exchange	43,371
Prebon Energy Inc	13,709
TFS Energy	15,024
	307,948

Compliance REC breakdown:

Illinois Commerce Commission	1,570,511

Schedule Page: 326 Line No.: 4 Column: a

DPL Energy is owned by Dayton Power and Light Company's parent company, DPL Inc.

Schedule Page: 326 Line No.: 12 Column: a

Dayton Power and Light Company owns a 4.9% share of Ohio Valley Electric Corp.

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	Potomac Electric Power-PJM	Potomac Electric Power-PJM	Potomac Electric Power-PJM	OS
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 reffered 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 (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
PJM OATT	Various intercon.					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**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered 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.
		11,591,710	11,591,710	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**	**11,591,710**	**11,591,710**	

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 Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
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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: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Midcontinent Ind Sys	NF				46		46
2	Operator Inc							
3	PJM Interconnection LLC	NF				79,108,472		79,108,472
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL					79,108,518		79,108,518

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	350,713
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	16,836
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	-1,017,149
6		2,517,660
7		
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46	TOTAL	1,868,060

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 335 Line No.: 6 Column: b

Recipient	Purpose	Amount
Nova Creative Group	Graphics Design	$ 16,599
AES	Expense Reimbursement for Verizon	7,830
Various Banks	Bank Fees	204,011
Dayton Area Chambers of Commerce	2015 Various Programs and Memberships	27,375
Dayton Development Coalition	2015 Membership Dues	50,000
Various	2014 Legal and consulting fees reclassified to regulatory asset	(1,432,492)
Ohio Electric Utility Association	2015 Membership Dues	11,527
Porter Wright Morris & McArthur	Legal Services	19,885
Southeastern Electric Exchange	2015 Membership	8,387
Ohio Chamber of Commerce	Membership	25,000
North American Transmission Forum	Membership	32,985
Dayton Business Committee	Membership	6,188
Other Under $5,000	Various	5,556
	Total	$(1,017,149)

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 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.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			8,167,779		8,167,779
2	Steam Production Plant	59,552,089	2,700,797			62,252,886
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	1,239,547				1,239,547
7	Transmission Plant	9,396,689				9,396,689
8	Distribution Plant	53,981,325				53,981,325
9	Regional Transmission and Market Operation					
10	General Plant	1,002,549				1,002,549
11	Common Plant-Electric					
12	TOTAL	125,172,199	2,700,797	8,167,779		136,040,775

B. Basis for Amortization Charges

The annual rate used to compute amortization expense for electric intangible plant remains at 14.29%.

Currently, in the intangibles (Acct 404) $14,933,869 of the plant balance is fully depreciated therefore, the basis for calculating amortization is $54,304,453 at December 31, 2015.

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	Production Plant						
13	Depreciation of						
14	$59,552,089 includes						
15	impairment adjustments						
16	of ($4,828,476).						
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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

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	PUCO Case No. 12-426-EL-SSO	2,000,000		2,000,000	
2					
3	PUCO Case No. 13-0837-EL-WVR	30,000		30,000	
4					
5	Ohio Consumers Council	169,598		169,598	
6					
7	Public Utility Commission of Ohio	1,654,509		1,654,509	
8					
9					
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46	TOTAL	3,854,107		3,854,107	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	2,000,000					1
							2
	928	30,000					3
							4
	928	169,598					5
							6
	928	1,654,509					7
							8
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		3,854,107					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:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $50,000.)
(7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
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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)		
					1
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	31,163,034		
4	Transmission	1,599,273		
5	Regional Market			
6	Distribution	2,882,091		
7	Customer Accounts	7,736,033		
8	Customer Service and Informational	737,556		
9	Sales			
10	Administrative and General	6,277,431		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	50,395,418		
12	Maintenance			
13	Production	15,859,002		
14	Transmission	573,843		
15	Regional Market			
16	Distribution	12,948,696		
17	Administrative and General	251,471		
18	TOTAL Maintenance (Total of lines 13 thru 17)	29,633,012		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	47,022,036		
21	Transmission (Enter Total of lines 4 and 14)	2,173,116		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	15,830,787		
24	Customer Accounts (Transcribe from line 7)	7,736,033		
25	Customer Service and Informational (Transcribe from line 8)	737,556		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	6,528,902		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	80,028,430		80,028,430
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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 Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	80,028,430		80,028,430
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,741,211		13,741,211
69	Gas Plant			
70	Other (provide details in footnote):	4,355,566		4,355,566
71	TOTAL Construction (Total of lines 68 thru 70)	18,096,777		18,096,777
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,299,260		1,299,260
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,299,260		1,299,260
77	Other Accounts (Specify, provide details in footnote):			
78	Miscellaneous Deferred Debit	159,769		159,769
79				
80	Other	723,180		723,180
81	Stores Expense	2,060,457		2,060,457
82	Transportation Expense	247,858		247,858
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,191,264		3,191,264
96	TOTAL SALARIES AND WAGES	102,615,731		102,615,731

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by 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.

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)	68,189,928	89,985,145	114,271,985	130,834,366
3	Net Sales (Account 447)	(67,188,929)	(99,881,979)	(148,504,525)	(187,493,579)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Transmission Rights - Sales (456)	(1,058,511)	(1,550,550)	(2,198,888)	(2,807,442)
8	Transmission Rights - Purchases (565)	46,470	117,792	288,976	383,407
9	Ancillary Services - Sales (447)	(36,322,526)	(70,825,179)	(105,900,521)	(139,987,094)
10	Ancillary Services - Sales (456)	(11,894,407)	(23,301,135)	(34,356,898)	(45,220,138)
11	Ancillary Services - Purchases (555)	35,635,364	64,577,941	100,993,646	130,970,532
12	Ancillary Services - Purchases (565)	25,042,558	43,034,092	63,127,885	78,725,156
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15	Footnote - entire page				
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46	TOTAL	12,449,947	2,156,127	(12,278,340)	(34,594,792)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 397 Line No.: 4 Column: e

See lines 4 through 12 for breakdown of Transmission Rights and Ancillary Services.

Schedule Page: 397 Line No.: 5 Column: e

See footnote on 397, Line 4, Column e

Schedule Page: 397 Line No.: 15 Column: a

Expenses and Revenues shown net of amounts deferred for recovery through TCRR and RPM regulatory assets.

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	24,551,004	$/mwh	7,554,792			1,454,521
2	Reactive Supply and Voltage	257,876	$/mw	7,505,570			6,692,774
3	Regulation and Frequency Response	53,750	$/mwh	2,107,190	72,924	$/mwh	2,885,596
4	Energy Imbalance			182,347			
5	Operating Reserve - Spinning	195,187	$/mwh	364,947	12,673	$/mwh	555,141
6	Operating Reserve - Supplement	10,793,308	$/mwh	2,715,745			832,605
7	Other	230,531		424,112			247,040
8	Total (Lines 1 thru 7)	36,081,656		20,854,703	85,597		12,667,677

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 2 Column: f

Includes multiple units of measure. 362,200 kvar and annual requirement/12.

Schedule Page: 398 Line No.: 7 Column: b

Includes purchases and sales for Black Start and Synchronous Condensing and multiple units of measure.

Schedule Page: 398 Line No.: 7 Column: c

Includes multiple units of measure.
Black Start 619,698 $/mw $535,827.
Synchronous Condensing 408,952 $/mwh $1,895

Schedule Page: 398 Line No.: 7 Column: g

Black Start $259,981

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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	3,005	8	900						
2	February	2,992	20	800						
3	March	2,786	6	800						
4	Total for Quarter 1									
5	April	2,192	1	700						
6	May	2,656	11	1400						
7	June	3,050	22	1600						
8	Total for Quarter 2									
9	July	3,272	29	1400						
10	August	3,004	31	1600						
11	September	3,112	3	1600						
12	Total for Quarter 3									
13	October	2,236	7	1600						
14	November	2,313	23	1000						
15	December	2,430	18	1900						
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	10,618,730
4	Nuclear	
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	10,618,730
10	Purchases	6,292,199
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
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)	16,910,929

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	3,905,044
23	Requirements Sales for Resale (See instruction 4, page 311.)	7,047,452
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,480,540
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,845
27	Total Energy Losses	466,048
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,910,929

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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,775,781	850,882	2,351	22	800
30	February	1,817,566	964,519	2,902	20	700
31	March	1,553,557	812,590	2,727	6	700
32	April	1,043,509	455,401	2,113	24	700
33	May	1,191,913	560,172	2,411	30	1600
34	June	1,303,297	650,758	2,647	14	1800
35	July	1,468,342	657,742	2,858	18	1700
36	August	1,504,225	833,719	2,682	16	1800
37	September	1,467,908	815,831	3,049	3	1800
38	October	1,417,531	847,977	2,182	5	2000
39	November	1,047,820	468,927	2,094	22	2000
40	December	1,319,479	658,667	2,282	15	1800
41	TOTAL	16,910,928	8,577,185			

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 401   Line No.: 22   Column: b

Reflects MWH that are consumed by customers that buy transmission, distribution, and generation services from DP&L.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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: *F. M. Tait* (b)			Plant Name: *F. M. Tait* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Int Combust - Note 1			Gas Turbine - Note 1
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1967			1995
4	Year Last Unit was Installed			1967			1998
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			11.00			294.00
6	Net Peak Demand on Plant - MW (60 minutes)			10			290
7	Plant Hours Connected to Load			11			628
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			10			304
10	When Limited by Condenser Water			10			256
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			49			46345
13	Cost of Plant: Land and Land Rights			16255			61402
14	Structures and Improvements			88348			849627
15	Equipment Costs			1121266			69911636
16	Asset Retirement Costs			0			0
17	Total Cost			1225869			70822665
18	Cost per KW of Installed Capacity (line 17/5) Including			111.4426			240.8934
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			11159			2591567
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			557227
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			51
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			35936			47340
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			47095			3196185
35	Expenses per Net KWh			961.1224			68.9650
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		OIL		OIL		GAS
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Barrels		Barrels		MCF
38	Quantity (Units) of Fuel Burned	0	97	0	1634	0	571988
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	85151	0	141523	0	1020
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	87.444	0.000	105.536	0.000	4.182
41	Average Cost of Fuel per Unit Burned	0.000	114.839	0.000	122.006	0.000	4.182
42	Average Cost of Fuel Burned per Million BTU	0.000	32.111	0.000	20.526	0.000	4.100
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	22.772	0.000	0.000	5.592	0.000
44	Average BTU per KWh Net Generation	0.000	7092.000	0.000	0.000	12798.000	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	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	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
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	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: *Killen Bio (See (d))* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		Resp Share St Note 3
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

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	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
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	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: *East Bend* (b)			Plant Name: *Miami Fort* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Resp. Share - Note 8			Resp. Share - Note 9		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1975		
4	Year Last Unit was Installed	1981			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	207.00			401.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			401		
7	Plant Hours Connected to Load	0			8267		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	186			368		
10	When Limited by Condenser Water	186			368		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			2417829		
13	Cost of Plant: Land and Land Rights	0			619144		
14	Structures and Improvements	0			16821646		
15	Equipment Costs	0			343698227		
16	Asset Retirement Costs	0			3515513		
17	Total Cost	0			364654530		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			909.3629		
19	Production Expenses: Oper, Supv, & Engr	61208			3257030		
20	Fuel	87737			56805267		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	-202587			1179787		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	21792			722		
26	Misc Steam (or Nuclear) Power Expenses	31438			2742151		
27	Rents	0			0		
28	Allowances	52			545		
29	Maintenance Supervision and Engineering	60631			324300		
30	Maintenance of Structures	39039			1680171		
31	Maintenance of Boiler (or reactor) Plant	-356209			4055004		
32	Maintenance of Electric Plant	147751			567755		
33	Maintenance of Misc Steam (or Nuclear) Plant	144121			4043199		
34	Total Production Expenses	34973			74655931		
35	Expenses per Net KWh	0.0000			30.8773		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				COAL		OIL
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				Tons		Barrels
38	Quantity (Units) of Fuel Burned	0	0	0	1029790	0	17141
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	11911	0	137255
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	53.068	0.000	71.602
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	52.838	0.000	80.476
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	2.218	0.000	13.960
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	2.307	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	10187.000	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	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	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
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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: *Sidney* (d)	Plant Name: *O.H. Hutchings* (e)	Plant Name: *O. H. Hutchings* (f)	Line No.
Int Combust - Note 1	Steam	Gas Turbine - Note 1	1
Conventional	Semi - Outdoors	Conventional	2
1968	1948	1968	3
1968	1953	1968	4
13.00	414.00	33.00	5
11	0	33	6
17	0	5	7
0	0	0	8
12	0	33	9
12	0	25	10
0	16	0	11
78	-3331	33	12
0	0	0	13
12679	0	183913	14
1076434	0	4385369	15
0	2571000	0	16
1089113	2571000	4569282	17
83.7779	6.2101	138.4631	18
0	238750	0	19
17642	-179970	3726	20
0	0	0	21
0	-206699	0	22
0	0	0	23
0	0	0	24
3640	65457	0	25
0	255926	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	529127	0	30
0	800	0	31
2189	240162	193556	32
0	0	0	33
23471	943553	197282	34
300.9103	-283.2642	5978.2424	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	OIL						GAS		36
	Barrels						MCF		37
0	134	0	0	0	0	0	11495	0	38
0	66989	0	0	0	0	0	170	0	39
0.000	74.853	0.000	0.000	0.000	0.000	0.000	0.437	0.000	40
0.000	131.728	0.000	0.000	0.000	0.000	0.000	0.437	0.000	41
0.000	46.819	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	22.618	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	4831.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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: *J. M. Stuart* (d)			Plant Name: *J. M. Stuart* (e)			Plant Name: *Yankee* (f)			Line No.
Resp. Share - Note 2			Resp. Share - Note 2			Gas Turbine - Note 1			1
Conventional			Semi-Outdoor			Conventional			2
1969			1970			1969			3
1969			1974			1970			4
4.00			854.00			139.00			5
3			718			48			6
193			8700			11			7
0			0			0			8
3			808			109			9
3			808			102			10
0			364			0			11
343			3572547			230			12
0			2104540			61072			13
0			79406638			596397			14
0			677590721			12571396			15
0			11999278			224956			16
0			771101177			13453821			17
0.0000			902.9288			96.7901			18
0			1410851			0			19
43401			84250203			125633			20
0			0			0			21
0			9022148			0			22
0			0			0			23
0			0			0			24
0			696957			264724			25
0			6855027			0			26
0			13979			0			27
0			513			0			28
0			729330			0			29
0			639106			0			30
0			22318349			0			31
0			3835833			49400			32
0			252826			0			33
43401			130025122			439757			34
126.5335			36.3956			1911.9870			35
			COAL		OIL		GAS		36
			Tons		Barrels		MCF		37
0	0	0	1587071	0	32222	0	3787	0	38
0	0	0	11724	0	135442	0	1020	0	39
0.000	0.000	0.000	53.051	0.000	77.687	0.000	33.175	0.000	40
0.000	0.000	0.000	53.160	0.000	80.736	0.000	33.175	0.000	41
0.000	0.000	0.000	2.267	0.000	14.193	0.000	32.524	0.000	42
0.000	0.000	0.000	0.000	2.434	0.000	0.000	54.623	0.000	43
0.000	0.000	0.000	0.000	10467.000	0.000	0.000	16800.000	0.000	44

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: *Killen* (d)	Plant Name: *Killen* (e)	Plant Name: *Monument* (f)	Line No.
Resp Share St Note 3	Resp Share Gas Note3	Int. Combust - Note1	1
Conventional	Conventional	Conventional	2
1982	1982	1968	3
1982	1982	1968	4
443.00	18.00	13.00	5
409	17	10	6
6829	6	10	7
0	0	0	8
402	16	12	9
402	12	12	10
102	0	0	11
2334976	80	53	12
2040683	0	0	13
106958075	0	12430	14
517656712	0	1162176	15
27677326	0	0	16
654332796	0	1174606	17
1477.0492	0.0000	90.3543	18
363795	0	0	19
55576716	52311	10370	20
0	0	0	21
5706116	0	0	22
0	0	0	23
0	0	0	24
321201	0	3196	25
2779815	0	0	26
0	0	0	27
835	0	0	28
377727	0	0	29
2960975	0	0	30
9271344	0	0	31
1835008	0	0	32
661107	0	0	33
79854639	52311	13566	34
34.1993	653.8875	255.9623	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
COAL		OIL					OIL		36
Tons		Barrels					Barrels		37
1071736	0	12676	0	0	0	0	77	0	38
11792	0	135676	0	0	0	0	120539	0	39
52.722	0.000	74.425	0.000	0.000	0.000	0.000	0.000	0.000	40
52.585	0.000	104.131	0.000	0.000	0.000	0.000	135.472	0.000	41
2.230	0.000	18.274	0.000	0.000	0.000	0.000	26.759	0.000	42
0.000	2.470	0.000	0.000	0.000	0.000	0.000	19.566	0.000	43
0.000	10856.000	0.000	0.000	0.000	0.000	0.000	7312.000	0.000	44

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: *W. H. Zimmer* (d)	Plant Name: *W. C. Beckjord* (e)	Plant Name: *Conesville* (f)	Line No.
Resp Share - Note 11	Resp. Share - Note 4	Resp. Share - Note 6	1
Conventional	Conventional	Conventional	2
1991	1969	1973	3
1991	1969	1973	4
401.00	230.00	139.00	5
467	0	154	6
5248	0	5253	7
0	0	0	8
379	210	129	9
371	207	129	10
0	0	0	11
1757655	0	490564	12
7311960	0	12346	13
232744388	0	6798015	14
862116261	0	124994812	15
987223	0	4572600	16
1103159832	0	136377773	17
2751.0220	0.0000	981.1351	18
2687941	20839	206085	19
40590907	217969	15132460	20
0	0	0	21
3601218	-341278	1351260	22
0	0	0	23
0	0	0	24
6523717	0	20090	25
0	695636	1028859	26
0	0	0	27
841	0	57	28
501057	40554	33201	29
1791928	2517118	144224	30
4004939	19864	2054044	31
1460626	1306	557191	32
7547909	51768	89820	33
68711083	3223776	20617291	34
39.0925	0.0000	42.0277	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	COAL					COAL		OIL	36
	Tons					Tons		Barrels	37
0	7000298	0	0	0	0	209042	0	916	38
0	12127	0	0	0	0	12170	0	137523	39
0.000	55.581	0.000	0.000	0.000	0.000	65.268	0.000	72.362	40
0.000	54.705	0.000	0.000	0.000	0.000	69.142	0.000	103.175	41
0.000	2.255	0.000	0.000	0.000	0.000	2.841	0.000	17.863	42
0.000	2.180	0.000	0.000	0.000	0.000	0.000	2.966	0.000	43
0.000	9664.000	0.000	0.000	0.000	0.000	0.000	10388.000	0.000	44

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	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: 1 Column: b

(1) This plant is designed for peak load services.

Schedule Page: 402 Line No.: 1 Column: c

See footnote on 402, Line 1, Column b

Schedule Page: 403 Line No.: 1 Column: d

See footnote on 402, Line 1, Column b

Schedule Page: 403 Line No.: 1 Column: f

See footnote on 402, Line 1, Column b

Schedule Page: 403.1 Line No.: 1 Column: d

(2) The Stuart units are owned by Dynegy (DYN), AEP Generation Resources Inc (AEP Generation) and the Respondent with undivided interests of 39%, 26%, and 35%, respectively. Fuel expenses in connection with production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses including limestone costs are shared on an ownership basis.

Schedule Page: 403.1 Line No.: 1 Column: e

See footnote on 402.1, Line 1, Column d

Schedule Page: 403.1 Line No.: 1 Column: f

See footnote on 402, Line 1, Column b

Schedule Page: 402.2 Line No.: 1 Column: c

(3) The Killen unit is owned by DYN and the Respondent with undivided interests of 33% and 67%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses including limestone costs are shared on an ownership basis.

Schedule Page: 403.2 Line No.: 1 Column: d

See footnote on 402.2, Line 1, Column c

Schedule Page: 403.2 Line No.: 1 Column: e

See footnote on 402.2, Line 1, Column d

Schedule Page: 403.2 Line No.: 1 Column: f

See footnote on 402, Line 1, Column b

Schedule Page: 402.3 Line No.: 1 Column: c

(9) The Miami Fort units are owned by DYN and the Respondent with undivided interests of 64% and 36%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 403.3 Line No.: 1 Column: d

(11) The Zimmer unit is owned by DYN, AEP Generation and the Respondent with undivided interests of 46.5%, 25.4%, and 28.1%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis; limestone costs associated with the use of the scrubber are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 403.3 Line No.: 1 Column: e

(4) The Beckjord unit is owned by Duke Energy Ohio, Inc. (DEO), AEP Generation and the Respondent with undivided interests of 37.5%, 12.5%, and 50%, respectively. Fuel expenses in connection with production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

Schedule Page: 403.3 Line No.: 1 Column: f

(6) The Conesville unit is owned by DYN, AEP Generation and the Respondent with undivided interests of 40%, 43.5%, and 16.5%, respectively. Fuel expenses in connection with the production of energy except amounts allocated to start-up and no-load costs are shared on an energy usage basis, while all other operating expenses are shared on an ownership basis.

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: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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 Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
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)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

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
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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	Yankee Solar #1	2010	1.00	1.0	1,388	3,435,257
2						
3						
4						
5						
6						
7						
8						
9						
10						
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
3,021	3,430		20,535	Solar		1
						2
						3
						4
						5
						6
						7
						8
						9
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	COMMONLY OWNED 345 KV							
2	Beckjord Station	Pierce Sub. A	354.00	345.00	Steel Tower	0.32		1
3								
4	Pierce Sub.	Foster Sub. A	345.00	345.00	Steel Tower	23.95		2
5								
6	Greene Sub.	Sugarcreek Sub. J	345.00	345.00	Steel Tower	1.45		1
7		J	345.00	345.00	Steel Pole	6.85		2
8								
9	Greene Sub.	Beatty Sub. A	345.00	345.00	Steel Tower	39.32		1
10		A	345.00	345.00	Wood H-Frame	0.62		1
11		A	345.00	345.00	Steel Tower	3.64		2
12		A	345.00	345.00	Steel Tower	5.42		1
13								
14	Marquis Sub.	Bixby Sub. A	345.00	345.00	Steel Tower	45.86		1
15		B	345.00	345.00	Steel Tower	17.30		1
16		B	345.00	345.00	Steel Tower		8.52	
17								
18	Stuart Sub.	Clinton Sub. L	345.00	345.00	Steel Tower	0.06		2
19		L	345.00	345.00	Steel Tower	54.04		1
20	Clinton Sub.	Greene Sub. L	345.00	345.00	Steel Tower	22.26		1
21		L	345.00	345.00	Wood H-Frame	0.58		1
22		L	345.00	345.00	Steel Tower	2.18		1
23		J	345.00	345.00	Steel Tower	1.16		2
24		J	345.00	345.00	Steel Tower	0.10		2
25								
26	Stuart Sub.	Killen Tie West A	345.00	345.00	Steel Tower	13.13		1
27	Killen Tie East	Marquis Sub. A	345.00	345.00	Steel Tower	3.90		1
28		A	345.00	345.00	Steel Tower	28.11		1
29								
30	Stuart Sub.	Foster Sub. A	345.00	345.00	Steel Tower	0.59		1
31		A	345.00	345.00	Steel Tower	55.18		1
32		J	345.00	345.00	Steel Tower	1.40		2
33		J	345.00	345.00	Steel H-Frame		1.57	3
34			345.00	345.00	Steel Pole	0.23		1
35								
36					TOTAL	2,123.73	274.68	270

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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	COMMONLY OWNED 345 KV							
2	Sugarcreek Sub.	Foster Sub. J	345.00	345.00	Steel Pole	24.11		2
3		J	345.00	345.00	Steel Tower	0.23		2
4		J	345.00	345.00	Steel H-Frame	1.57		3
5		J	345.00	345.00	Steel Pole	1.40		1
6								
7	Beatty Sub.	Bixby Sub. B	345.00	345.00	Steel Tower	4.69		1
8		B	345.00	345.00	Steel Tower	8.52		2
9								
10	Bixby Sub.	Point N (Kirk) K	345.00	345.00	Steel Tower	14.81		2
11								
12	Stuart Sub.	Spurlock Tap A	345.00	345.00	Steel Tower	7.62		1
13								
14	Spurlock Tap	Zimmer Sta. A	345.00	345.00	Steel Tower	27.51		1
15		E	345.00	345.00	Steel Tower	0.78		2
16								
17	Zimmer Sta.	Foster Jct. E	345.00	345.00	Steel Tower		0.28	
18		E	345.00	345.00	Steel Tower		0.23	
19		E	345.00	345.00	Steel Tower		0.80	
20		A	345.00	345.00	Steel Tower	9.52		1
21		E	345.00	345.00	Steel Tower		23.38	
22	Foster Jct.	Port Union Sub. E	345.00	345.00	Steel Tower	11.70		2
23								
24	Zimmer Sta.	Silver Grove Sub. E	345.00	345.00	Steel Tower	13.55		1
25		E	345.00	345.00	Steel Tower	2.01		2
26								
27	Silver Grove Sub.	Red Bank Sub. E	345.00	345.00	Steel Tower		2.01	
28		E	345.00	345.00	Steel Tower	17.01		2
29	Red Bank Sub	Terminal Sub. E	345.00	345.00	Steel Tower	6.65		2
30	Stuart Sub.	Atlanta Sub. B	345.00	345.00	Steel Tower		0.06	2
31		B	345.00	345.00	Steel Tower	70.14		1
32								
33								
34								
35								
36					TOTAL	2,123.73	274.68	270

TRANSMISSION LINE STATISTICS

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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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	COMMONLY OWNED 345 KV							
2	Atlanta Sub.	Adkins Sub. A	345.00	345.00	Steel Tower	4.80		1
3		A	345.00	345.00	Steel Tower	5.94		1
4	Adkins Sub.	Beatty Sub. A	345.00	345.00	Steel Tower	9.26		1
5		A	345.00	345.00	Steel Tower		3.54	
6		A	345.00	345.00	Steel Tower	0.16		1
7								
8	Bixby Sub.	Conesville Sub. B	345.00	345.00	Steel Tower		14.87	
9		B	345.00	345.00	Wood H-Frame	50.86		1
10								
11	Conesville Sub.	Hyatt Sub. C	345.00	345.00	Steel Tower	56.98		1
12		D	345.00	345.00	Steel Tower	9.09		2
13		D	345.00	345.00	Steel Pole	1.78		2
14		D	345.00	345.00	Wood H-Frame	0.48		2
15								
16	Seven Mile Tie	Miami Fort Sta. I	345.00	345.00	Steel Tower		33.25	
17		I	345.00	345.00	Steel Tower	1.37		1
18	Miami Fort Sta.	Todhunter Sub. I	345.00	345.00	Steel Tower	33.25		2
19		I	345.00	345.00	Steel Tower	9.57		1
20								
21	Foster	Bath J	345.00	345.00	Steel Tower		7.25	2
22		J	345.00	345.00	Steel Pole		30.96	2
23		J	345.00	345.00	Steel Pole	0.41		1
24		J	345.00	345.00	Steel H-Frame		1.57	3
25								
26	TOTAL COMMONLY OWNED					733.42	128.29	88
27	345 KV FACIL-SEE NOTE (M)							
28								
29	WHOLLY OWNED 345 KV							
30	Greene Sub.	Sugarcreek Sub.	345.00	345.00	Steel Tower	2.81		2
31			345.00	345.00	Steel Pole	0.36		2
32								
33	Sugarcreek Sub.	Foster Sub.	345.00	345.00	Steel Tower		2.81	
34			345.00	345.00	Steel Pole		0.36	
35								
36					TOTAL	2,123.73	274.68	270

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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 345 KV							
2	Greene Sub.	Bath Sub.	345.00	345.00	Steel Tower	4.51		2
3			345.00	345.00	Steel Pole	0.06		1
4	Bath Sub.	Miami Sub.	345.00	345.00	Steel Pole	0.06		1
5			345.00	345.00	Steel Tower	20.71		2
6								
7	Miami Sub.	Shelby Sub.	345.00	345.00	Steel Tower	7.74		1
8			345.00	345.00	Steel Tower	17.54		1
9	Shelby Sub.	Dinsmore Inter-Conn Pt.						
10		w/Ohio Power Co.	345.00	345.00	Steel Tower	9.25		1
11								
12	Miami Sub.	West Milton Sub.	345.00	345.00	Steel Pole	0.44		1
13			345.00	345.00	Steel Pole	8.40		2
14								
15	West Milton Sub.	Seven Mile Tie	345.00	345.00	Steel Pole	9.81		1
16			345.00	345.00	Steel Pole	1.71		1
17			345.00	345.00	Steel Pole	4.13		1
18			345.00	345.00	Steel Pole	21.70		1
19			345.00	345.00	Steel Pole	0.12		1
20								
21	Killen Sub.	Stuart Tie West	345.00	345.00	Steel Tower	3.52		1
22			345.00	345.00	Steel Pole	2.01		
23		Non-Energized		345.00	Steel Tower	2.06		1
24								
25	Killen Sub.	Marquis Tie East	345.00	345.00	Steel Tower	6.04		1
26			345.00	345.00	Steel H-Frame	0.42		1
27								
28	TOTAL WHOLLY OWNED					123.40	3.17	25
29	345 KV FACIL-SEE NOTE (M)							
30								
31	WHOLLY OWNED 138 KV							
32	Hutchings Sub.	Trenton Tie (Ohio Power)	138.00	138.00	Wood H-Frame	2.02		1
33			138.00	138.00	Wood Pole	1.24		1
34			138.00	138.00	Steel Tower	11.39		2
35								
36					TOTAL	2,123.73	274.68	270

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Hutchings Sub.	Hillsboro Tie (Ohio Power)	138.00	138.00	Wood Pole	0.04		1
3			138.00	138.00	Steel Tower	0.14		1
4			138.00	138.00	Steel Tower		0.17	
5			138.00	138.00	Steel Tower		11.39	
6			138.00	345.00	Steel Tower	0.21		1
7			138.00	345.00	Steel Tower	4.03		1
8			138.00	138.00	Wood Pole	0.03		1
9								
10	Hutchings Sub.	Sugarcreek Sub.	138.00	138.00	Wood H-Frame	10.32		1
11			138.00	138.00	Wood Pole	0.13		1
12			138.00	138.00	Steel Tower	0.17		2
13			138.00	138.00	Steel Tower	0.90		1
14			138.00	138.00	Underground	0.39		1
15								
16	Miami Sub.	West Milton Sub.	138.00	345.00	Steel Pole	0.18		1
17			138.00	345.00	Steel Pole		8.40	
18			138.00	345.00	Steel Pole	0.21		1
19								
20	Hutchings Sub.	Crown Sub.	138.00	138.00	Wood Pole	10.30		1
21			138.00	138.00	Wood Pole	1.02		2
22			138.00	138.00	Wood H-Frame	1.14		3
23			138.00	138.00	Steel Tower	0.28		2
24			138.00	138.00	Steel Tower	0.08		1
25								
26	Trebein Sub.	Bath Sub.	138.00	138.00	Steel Tower		0.18	
27			138.00	138.00	Wood Pole	0.31		1
28			138.00	138.00	Steel Tower	4.07		2
29								
30	Bath Sub.	Urbana Sub.	138.00	138.00	Steel Tower	4.36		2
31			138.00	138.00	Wood H-Frame	20.69		1
32			138.00	138.00	Wood Pole	0.23		1
33								
34								
35								
36					TOTAL	2,123.73	274.68	270

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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Urbana Sub.	Darby Sub.	138.00	138.00	Wood Pole	0.04		1
3			138.00	138.00	Wood H-Frame	30.68		1
4			138.00	138.00	Steel Tower		0.51	
5			138.00	138.00	Steel Pole	1.22		1
6								
7	Darby Sub.	Delaware Sub (CSP)	138.00	138.00	Wood H-Frame	14.13		1
8			138.00	138.00	Steel Pole	0.02		1
9								
10	Greene Sub.	Trebein Sub.	138.00	138.00	Wood H-Frame	0.21		1
11			138.00	138.00	Steel Tower	0.94		2
12			138.00	138.00	Steel Tower	0.29		2
13			138.00	138.00	Steel Tower	0.08		1
14								
15	Greene Sub.	Airway Sub.	138.00	138.00	Steel Tower	6.46		1
16			138.00	138.00	Steel Tower	0.65		2
17								
18	Greene Sub.	Monument Sub.	138.00	138.00	Wood Pole	0.12		1
19			138.00	138.00	Wood Pole	1.93		1
20			138.00	138.00	Steel Tower	0.07		1
21			138.00	138.00	Steel Tower	7.72		2
22			138.00	138.00	Steel Tower	0.07		1
23			138.00	138.00	Steel Pole	0.49		1
24								
25	Monument Sub.	Wyandot Sub.	138.00	138.00	Underground	1.19		
26			138.00	138.00	Underground	1.25		
27								
28	Monument Sub.	Webster Sub.	138.00	138.00	Wood Pole	0.96		1
29			138.00	138.00	Steel Pole	1.22		1
30								
31								
32								
33								
34								
35								
36					TOTAL	2,123.73	274.68	270

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.
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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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	WHOLLY OWNED 138 KV							
2	Needmore Sub.	Northridge Sub.	138.00	138.00	Wood Pole	0.61		1
3			138.00	138.00	Steel Tower	1.62		2
4			138.00	138.00	Wood Pole	0.03		1
5			138.00	138.00	Steel Tower	0.01		1
6	Northridge Sub.	Miami Sub.	138.00	138.00	Wood H-Frame	2.77		1
7			138.00	138.00	Wood Pole	0.52		1
8			138.00	138.00	Steel Tower	4.84		2
9			138.00	138.00	Steel Tower	1.40		3
10			138.00	138.00	Steel Tower	0.04		1
11								
12	Sugarcreek Sub.	Bellbrook Sub.	138.00	138.00	Wood Pole	0.10		1
13			138.00	138.00	Wood H-Frame	1.56		1
14			138.00	138.00	Wood Pole	1.11		1
15	Bellbrook Sub.	Alpha Sub.	138.00	138.00	Wood H-Frame	1.83		1
16			138.00	138.00	Wood Pole	0.29		1
17			138.00	138.00	Steel Pole	0.76		2
18								
19	Sugarcreek Sub.	Centerville Sub.	138.00	138.00	Wood Pole	3.89		1
20			138.00	138.00	Wood Pole	1.30		2
21			138.00	138.00	Wood Pole	1.07		1
22			138.00	138.00	Wood Pole	0.05		2
23								
24	Centerville	Hempstead Sub.	138.00	138.00	Wood Pole	0.30		1
25			138.00	138.00	Wood Pole	3.00		1
26								
27	Alpha Sub.	Greene Sub.	138.00	138.00	Wood Pole	0.83		1
28			138.00	138.00	Wood Pole	1.39		2
29			138.00	138.00	Wood H-Frame	2.45		1
30			138.00	138.00	Wood Pole	0.10		1
31								
32								
33								
34								
35								
36					TOTAL	2,123.73	274.68	270

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.
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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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	WHOLLY OWNED 138 KV							
2	Eldean Sub.	Sidney Sub.	138.00	138.00	Wood Pole	0.87		1
3			138.00	138.00	Wood H-Frame	11.82		1
4			138.00	138.00	Wood Pole	0.07		1
5			138.00	138.00	Wood Pole	3.70		1
6			138.00	138.00	Steel Tower	2.32		3
7			138.00	138.00	Steel Pole	0.13		1
8			138.00	138.00	Steel Pole	0.06		1
9			138.00	138.00	Steel Pole	5.26		2
10			138.00	138.00	Wood Pole	0.37		2
11								
12	Webster Sub.	Needmore Sub.	138.00	138.00	Wood Pole	0.19		1
13			138.00	138.00	Steel Tower	0.78		2
14			138.00	138.00	Steel Tower	0.05		1
15			138.00	138.00	Wood Pole	0.01		1
16			138.00	138.00	Steel Tower	0.56		2
17								
18	Sidney Sub.	Shelby Sub.	138.00	138.00	Wood Pole	0.08		1
19			138.00	138.00	Steel Tower		2.32	
20			138.00	138.00	Wood H-Frame	4.68		1
21			138.00	138.00	Wood Pole	2.17		2
22								
23	Shelby Sub.	Amsterdam Sub.	138.00	138.00	Wood Pole	24.47		1
24			138.00	138.00	Wood Pole	0.98		2
25								
26	West Milton Sub.	Greenville Sub.	138.00	138.00	Steel Pole	11.45		1
27			138.00	138.00	Wood Pole	9.18		1
28								
29	Shelby Sub.	Quincy Sub.	138.00	138.00	Wood Pole		2.18	
30			138.00	138.00	Wood H-Frame	5.96		1
31			138.00	138.00	Wood Pole	0.01		1
32			138.00	138.00	Wood Pole	1.38		1
33	Quincy Sub.	Logan Sub.	138.00	138.00	Wood Pole	10.13		1
34			138.00	138.00	Wood Pole	0.02		1
35								
36					TOTAL	2,123.73	274.68	270

TRANSMISSION LINE STATISTICS

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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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Miami Sub.	New Carlisle	138.00	345.00	Steel Tower		5.95	
3			138.00	138.00	Wood Pole	0.15		1
4			138.00	138.00	Steel Pole	0.88		2
5			138.00	138.00	Wood Pole	0.17		2
6			138.00	138.00	Wood Pole	0.07		1
7								
8	Bath Sub.	New Carlisle Sub.	138.00	345.00	Steel Tower		14.65	
9			138.00	138.00	Wood Pole	0.12		1
10			138.00	345.00	Steel Pole	0.05		1
11			138.00	138.00	Steel Pole		0.88	
12			138.00	138.00	Wood Pole		0.17	
13			138.00	138.00	Wood Pole	0.08		1
14								
15	Knollwood Sub.	Overlook Sub.	138.00	138.00	Steel Tower		4.53	
16	Overlook Sub.	Monument Sub.	138.00	138.00	Wood Pole	1.27		1
17			138.00	138.00	Steel Tower	1.58		1
18			138.00	138.00	Steel Tower	1.54		2
19								
20	Clark (Ohio Edison)	Urbana	138.00	138.00	Steel Pole	2.48		1
21								
22	Greene Sub.	Knollwood Sub.	138.00	138.00	Wood Pole	0.22		1
23			138.00	138.00	Steel Tower		3.40	
24								
25	Monument Sub.	Webster Sub.	138.00	138.00	Steel Tower		1.54	
26			138.00	138.00	Steel Tower	2.25		1
27								
28	Blue Jacket Sub.	Kirby (Ohio Edison)	138.00	138.00	Steel Pole	0.16		2
29			138.00	138.00	Wood Pole	18.00		1
30			138.00	138.00	Steel Pole	3.45		1
31								
32								
33								
34								
35								
36					TOTAL	2,123.73	274.68	270

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHOLLY OWNED 138 KV							
2	Miami Sub.	Eldean Sub.	138.00	138.00	Wood H-Frame	3.84		1
3			138.00	138.00	Wood H-Frame	1.77		2
4			138.00	138.00	Wood Pole	0.14		1
5			138.00	138.00	Steel Tower	0.06		1
6			138.00	138.00	Steel Tower		1.40	3
7			138.00	138.00	Wood H-Frame	6.26		1
8			138.00	138.00	Steel Pole	0.15		1
9			138.00	138.00	Steel Pole		5.26	2
10			138.00	138.00	Wood Pole		0.37	2
11								
12	TOTAL WHOLLY OWNED					316.88	63.30	157
13	138 KV FACIL-SEE NOTE (M)							
14								
15	WHOLLY OWNED 69 KV							
16	69 KV Lines	H Non-Energized		138.00	Wood Pole	0.13		
17			69.00	69.00	Wood Pole	709.46	9.26	
18			69.00	69.00	Wood H-Frame	0.22	1.14	
19			69.00	69.00	Steel Pole	22.67	3.91	
20			69.00	69.00	Steel Tower	50.65	26.96	
21			69.00	138.00	Steel Pole	0.55	0.43	
22			69.00	69.00	Underground	5.48		
23			69.00	138.00	Wood Pole	103.84	3.95	
24			69.00	138.00	Wood H-Frame	8.78	1.77	
25			69.00	138.00	Steel Tower	8.55	29.00	
26		H Non-Energized		69.00	Wood Pole	3.40		
27								
28	All 69 KV Lines							
29								
30	TOTAL WHOLLY OWNED					913.73	76.42	
31	69 KV FACIL-SEE NOTE (M)							
32								
33								
34								
35								
36					TOTAL	2,123.73	274.68	270

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	WHOLLY OWNED 34.5 KV							
2	34.5 KV Lines	H Non-Energized	34.50	34.50	Wood Pole	3.98		
3			34.50	69.00	Wood Pole	8.05		
4			34.50	34.50	Wood Pole	24.27	1.08	
5		H Non-Energized	34.50	69.00	Wood H-Frame		1.14	
6		H Non-Energized	34.50	138.00	Steel Tower		1.28	
7								
8	TOTAL WHOLLY OWNED					36.30	3.50	
9	34.5 KV FAC-SEE NOTE (M)							
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					TOTAL	2,123.73	274.68	270

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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
1414 ACSR	14,534	49,231	63,765	9,708	34,075		43,783	2
								3
2-1024.5 ACAR	341,950	829,456	1,171,406					4
								5
2-1024.5 ACAR					47,820		47,820	6
2-1024.5 ACAR	84,936	369,044	453,980					7
								8
2-1024.5 ACAR					212,342		212,342	9
2-1024.5 ACAR								10
2-1024.5 ACAR								11
2-1024.5 ACAR	407,287	1,354,258	1,761,545					12
								13
2-983.1 ACAR					338,882		338,882	14
2-954 ACSR								15
2-954 ACSR	437,658	1,971,550	2,409,208					16
								17
2-1024.5 ACAR					72,075		72,075	18
2-1024.5 ACAR								19
2-1024.5 ACAR					1,094		1,094	20
2-1024.5 ACAR								21
2-1024.5 ACAR								22
2-1024.5 ACAR								23
2-1024.5 ACAR	795,465	3,926,100	4,721,565					24
								25
2-983.1 ACAR					609		609	26
2-983.1 ACAR								27
2-983.1 ACAR	110,254	2,062,684	2,172,938					28
								29
2-1024 ACAR				13,869	7,873		21,742	30
2-1024 ACAR								31
2-1024 ACAR								32
2-1024 ACAR								33
2-1024 ACAR	380,541	1,725,550	2,106,091					34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

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)
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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
2-1024.5 ACAR					2,848		2,848	2
2-1024.5 ACAR								3
2-1024.5 ACAR								4
2-1024.5 ACAR	423,046	1,111,577	1,534,623					5
								6
2-954 ACSR					161		161	7
2-954 ACSR	238,833	711,521	950,354					8
								9
2-954 ACSR	148,565	400,705	549,270		20,428		20,428	10
								11
2-954 ACSR				19,378	63,314		82,692	12
								13
2-954 ACSR								14
2-954 ACSR	262,436	1,958,857	2,221,293					15
								16
2-954 ACSR				28,780	193,048		221,828	17
2-954 ACSR								18
2-954 ACSR								19
2-954 ACSR								20
2-1024.5 ACAR								21
2-954 ACSR	445,514	1,958,704	2,404,218					22
								23
2-1113 ACSR				19,340	7,060		26,400	24
2-1113 ACSR	536,138	9,497,379	10,033,517					25
								26
2-1113 ACSR								27
2-954 ACSR								28
2-954 ACSR				9,670	278		9,948	29
2-954 ACSR								30
2-954 ACSR	106,955	592,415	699,370					31
								32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

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)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2-983.1 ACAR					285,509		285,509	2
2-983.1 ACAR								3
2-983.1 ACAR								4
2-983.1 ACAR								5
2-983.1 ACAR	679,517	2,139,786	2,819,303					6
								7
2-954 ACSR					2,208		2,208	8
2-954 ACSR	360,943	1,454,639	1,815,582					9
								10
2-954 ACSR					70,879		70,879	11
2-954 ACSR								12
2-954 ACSR								13
2-954 ACSR	446,864	1,784,450	2,231,314					14
								15
2-954 ACSR					19,183		19,183	16
2-954 ACSR								17
2-954 ACSR				24,176	37,457		61,633	18
2-954 ACSR	2,422,347	8,356,519	10,778,866					19
								20
2-1024.5 ACAR					8,501		8,501	21
2-1024.5 ACAR								22
2-1024.5 ACAR								23
2-1024.5 ACAR		17,861,060	17,861,060					24
								25
	8,643,783	60,115,485	68,759,268	124,921	1,425,644		1,550,565	26
								27
								28
								29
2-1024.5 ACAR								30
2-1024.5 ACAR		568,167	568,167					31
								32
2-1024.5 ACAR								33
2-1024.5 ACAR		128,444	128,444					34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

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)
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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
2-1024.5 ACAR					6,985		6,985	2
2-1024.5 ACAR								3
2-1024.5 ACAR					4,286		4,286	4
2-1024.5 ACAR	996,644	2,555,134	3,551,778					5
								6
2-1024.5 ACAR					1,664		1,664	7
2-1024.5 ACAR								8
					776		776	9
2-1024.5 ACAR	812,634	2,773,147	3,585,781					10
								11
2-1024.5 ACAR					24,366		24,366	12
2-1024.5 ACAR								13
								14
2-1024.5 ACAR								15
2-1024.5 ACAR								16
2-1024.5 ACAR								17
2-1024.5 ACAR								18
2-1024.5 ACAR	2,641,058	9,923,490	12,564,548					19
								20
2-954 ACSR	147,277	3,153,325	3,300,602		360,826		360,826	21
2-954 ACSR								22
2-983.1 ACSR								23
								24
2-954 ACSR					366,088		366,088	25
2-954 ACSR	266,243	2,647,257	2,913,500					26
								27
	4,863,856	21,748,964	26,612,820		764,991		764,991	28
								29
								30
								31
795 ACSR					689		689	32
795 ACSR								33
795 ACSR	352,374	691,151	1,043,525					34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
795 ACSR					9,265		9,265	2
795 ACSR								3
795 ACSR								4
795 ACSR								5
795 ACSR								6
2-795 ACSR								7
477 ACSR	87,719	569,993	657,712					8
								9
636 ACSR					11,863	871	12,734	10
795 AL								11
636 ACSR								12
636 ACSR								13
2000 CU	89,431	2,721,463	2,810,894					14
								15
1351.5 AL								16
2-1024.5 ACAR								17
2-1024.5 ACAR		391,485	391,485					18
								19
636 ACSR					27,543		27,543	20
636 ACSR								21
636 ACSR								22
636 ACSR								23
636 ACSR		674,181	674,181					24
								25
477 ACSR								26
477 ACSR								27
477 ACSR		243,254	243,254					28
								29
477 ACSR					159,674		159,674	30
477 ACSR								31
477 ACSR		1,596,042	1,596,042					32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

TRANSMISSION LINE STATISTICS (Continued)

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								1
477 ACSR					1,919		1,919	2
795 ACSR								3
795 ACSR								4
4/0 ACSR	240,900	809,994	1,050,894					5
								6
636 ACSR								7
477 ACSR	322,028	558,032	880,060					8
								9
1351.5 AL					9,984		9,984	10
636 ACSR								11
1351.5 ACSR								12
1351.5 AL	20,533	166,782	187,315					13
								14
636 ACSR					16,036		16,036	15
795 ACSR		413,727	413,727					16
								17
1351.5 ACSR					3,475		3,475	18
1351.5 AL								19
1351.5 ACSR								20
1351.5 ACSR								21
1351.5 AL								22
1351 AL	83,529	967,356	1,050,885					23
								24
1250 CU								25
1250 CU		488,273	488,273					26
								27
1351.5 AL								28
1351.5 AL	6,971	271,871	278,842					29
								30
								31
								32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

TRANSMISSION LINE STATISTICS (Continued)

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
636 ACSR								2
636 ACSR								3
4/0 ACSR								4
636 ACSR		162,184	162,184					5
636 ACSR					7,086		7,086	6
636 ACSR								7
636 ACSR								8
1351.5 ACSR								9
1351.5 ACSR		625,999	625,999					10
								11
1351.5 AL					10,379		10,379	12
1351.5 ACSR								13
1351.5 AL								14
1351.5 ACSR								15
1351.5 AL								16
1351.5 ACSR	33,457	1,118,508	1,151,965					17
								18
1351.5 AL					6,390		6,390	19
1351.5 AL								20
636 ACSR								21
636 ACSR		644,474	644,474					22
								23
1351.5 AL								24
636 ACSR		112,008	112,008					25
								26
1351.5 AL					481		481	27
1351.5 AL								28
1351.5 ACSR								29
1351.5 AL	46,920	822,668	869,588					30
								31
								32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

TRANSMISSION LINE STATISTICS (Continued)

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								1
477 ACSR					22,968		22,968	2
636 ACSR								3
636 ACSR								4
795 ACSR								5
636 ACSR								6
1351.5 AL								7
1351.5 ACSR								8
1351.5 ACSR								9
1351.5 ACSR	71,441	3,251,226	3,322,667					10
								11
1351.5 ACSR								12
636 ACSR								13
636 ACSR								14
477 ACSR		186,142	186,142					15
1351.5 ACSR								16
								17
795 ACSR					8,736		8,736	18
795 ACSR								19
795 ACSR								20
795 ACSR	257,706	1,406,143	1,663,849					21
								22
795 ACSR					3,462		3,462	23
795 ACSR	78,824	1,977,683	2,056,507					24
								25
795 ACSR					273		273	26
795 ACSR	782,220	2,403,447	3,185,667					27
								28
795 ACSR								29
477 ACSR								30
4/0 ACSR								31
477 ACSR								32
477 ACSR								33
1351.5 AL		624,948	624,948					34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

TRANSMISSION LINE STATISTICS (Continued)

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								1
2-1024.5 ACAR								2
1351.5 AL					4,281		4,281	3
1351.5 ACSR								4
1351.5 ACSR								5
1351.5 ACSR								6
								7
2-1024.5 ACAR					4,026		4,026	8
1351.5 ACSR								9
1351.5 AL								10
1351.5 ACSR								11
1351.5 ACSR								12
1351.5 ACSR	61,294	2,566,216	2,627,510					13
								14
1351.5 ACSR								15
1351.5 ACSR								16
2-300 CU								17
795 ACSR								18
								19
795 ACSR		594,711	594,711					20
								21
1351.5 ACSR								22
1351.5 ACSR								23
								24
795 ACSR								25
2-300 CU		495,014	495,014					26
								27
795 AL								28
795 AL								29
795 AL	1,100,000	2,924,529	4,024,529					30
								31
								32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
636 ACSR					25,493		25,493	2
636 ACSR								3
636 ACSR								4
1351.5 ACSR								5
1351.5 ACSR								6
1351.5 ACSR								7
1351.5 ACSR								8
1351.5 ACSR								9
1351.5 ACSR		1,044,626	1,044,626					10
								11
	3,635,347	31,524,130	35,159,477		334,023	871	334,894	12
								13
								14
				308,308	636,715		945,023	15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
	10,804,013	82,056,036	92,860,049					28
								29
	10,804,013	82,056,036	92,860,049	308,308	636,715		945,023	30
								31
								32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

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
								2
								3
								4
								5
								6
								7
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								32
								33
								34
								35
	27,946,999	195,444,615	223,391,614	433,229	3,161,373	871	3,595,473	36

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: a

(A) These 345 KV transmission lines are owned by Duke Energy Ohio, Inc. (DEO), Columbus Southern Power (CSP) and the Respondent as tenants in common with undivided interests of 30%, 35%, and 35%, respectively.

(B) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 33-1/3%, 33-1/3%, and 33-1/3%, respectively.

(C) This 345 KV transmission line is owned by DEO, CSP and Respondent as tenants in common with undivided interests of 16.86%, 66.28%, and 16.86%, respectively.

(D) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 8.43%, 83.14%, and 8.43%, respectively.

(E) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 28%, 36%, and 36%, respectively.

(F) Whereas mileage shown for each line represents data applicable to the entire facility owned by the three companies, Respondent’s undivided interests in total of such facilities are shown, for statistical purposes only, in footnote (L).

(G) For commonly owned facilities, the costs and expenses shown for each line and in total represent Respondent’s allocated share of total applicable costs and expenses.

(H) These items include lines in process of conversion to another voltage class and lines under study as to possible reclassification to other accounts.

(I) These 345 KV transmission lines are owned by DEO and Respondent as tenants in common with undivided interests of 55% and 45%, respectively.

(J) These 345 KV transmission lines are owned by DEO and Respondent as tenants in common with undivided interests of 50% and 50%, respectively.

(K) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 17.5%, 60%, and 22.5%, respectively.

(L) These 345 KV transmission lines are owned by DEO, CSP and Respondent as tenants in common with undivided interests of 30%, 10.65% and 59.35%, respectively.

(M)

COL	TOTAL COMMONLY OWNED 345KV FACILITIES	RESPONDENT’S EQUIVALENT SHARE	TOTAL WHOLLY OWNED 345KV FACILITIES	RESPONDENT’S TOTAL 345KV FACILITIES
F				
G				
J		8,643,783	4,863,856	13,507,639
K		60,115,485	21,748,964	81,864,449
L		68,759,268	26,612,820	95,372,088

COL	TOTAL 138KV	TOTAL 69KV	TOTAL 34.5KV	TOTAL 69KV & 34.5KV	RESPONDENT’S PORTION
F					
G					
J	3,635,347	N/A	N/A	10,804,013	27,946,999
K	31,524,130	N/A	N/A	82,056,036	195,444,615
L	35,159,477	N/A	N/A	92,860,049	223,391,614

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Moraine	Southtown	0.86	Steel Pole	0.13	2	2
2							
3							
4							
5							
6							
7							
8							
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35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.86		0.13	2	2

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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
477 ACSR		Vertical	69		596,937	127,077		724,014	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					596,937	127,077		724,014	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	WHOLLY OWNED SUBSTATIONS: (1)				
2	Adkins-Darby Twp., Piqua Co.	T-Supv. Control	345.00		
3	Air Park-Clinton Co.	D-Supv. Control	69.00	12.50	
4	Airway-E. of Dayton	T&D-Supv. Control	138.00	69.00	
5		T&D-Supv. Control	69.00	12.50	
6	Alpha-S. Alpha-Bellbrook Rd.	T-Supv. Control	138.00	69.00	
7	Amsterdam-S. of New Bremen	T&D-Supv. Control	138.00	69.00	
8		T&D-Supv. Control	69.00	12.50	
9	Atlanta-St. Rt. 207, N. Holland	T-Supv. Control	345.00	69.00	
10	Bath-Beavercreek Twp., Greene Co.	T-Supv. Control	345.00	138.00	
11		T-Supv. Control	138.00	69.00	
12	Bellbrook South St., Bellbrook	T&D-Supv. Control	138.00	12.50	
13	Bellefontaine-Detroit	T&D-Supv. Control	69.00	4.16	
14		T&D-Supv. Control	69.00	12.50	
15	Benner-Benner Rd., Miamisburg	T&D-Supv. Control	69.00	12.50	
16	Blue Jacket-Lake Twp., Logan Co.	T&D-Supv. Control	138.00	69.00	
17		T&D-Supv. Control	69.00	12.50	
18	Botkins-1 mi. E. of Botkins	T&D-Supv. Control	69.00	12.50	
19	Brookville-N.E. of Brookville	T&D-Supv. Control	69.00	12.50	
20	Camden-Summers Twp., Preble Co.	D-Supv. Control	69.00	12.50	
21	Carpenter-Sugarcreek Twp.	D-Supv. Control	69.00	12.50	
22	Carrollton-W. Carrollton	T&D-Supv. Control	69.00	12.50	
23	Cedarville-Murdock Road, Cedarville	D-Supv. Control	69.00	12.50	
24	Celina-Celina	T-Supv. Control	69.00		
25	Centerville-Centerville	T&D-Supv. Control	138.00	12.50	
26	Cisco-N. of Sidney	D-Supv. Control	69.00	12.50	
27	Clinton-S. of Wilmington	T-Supv. Control	345.00	69.00	
28	Coldwater-S.W. of Coldwater	T&D-Supv. Control	69.00	12.50	
29	Columbus St. Wilmington	D-Supv. Control	69.00	12.50	
30	Covington-Covington	T&D-Supv. Control	69.00	12.50	
31	Crown-Hoover Ave., Dayton	T-Supv. Control	138.00	69.00	
32	Crystal-Rt. 122 S. of Eaton	T&D-Supv. Control	69.00	12.50	
33	Darby-U.S. 33, Marysville	T&D-Supv. Control	138.00	69.00	
34		T&D-Supv. Control	69.00	12.50	
35	Dayton Mall-Miami Twp., Montgomery County	T&D-Supv. Control	69.00	12.50	
36	Delco-Kettering, Kettering	T&D-Supv. Control	69.00	12.50	
37	Dixie-Dorothy Lane, Kettering	T&D-Supv. Control	69.00	12.50	
38	Eagle-N. Germany Trebein Rd., Beavercreek	T&D-Supv. Control	69.00	12.50	
39	Eaker-Eaker St., Dayton	D-Supv. Control	69.00	12.50	
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Eldean-Miami Co.	T&D-Supv. Control	138.00	69.00	
3		T&D-Supv. Control	138.00	12.50	
4	Englewood-Taywood Rd., Englewood	T&D-Supv. Control	69.00	12.50	
5	Caesars Creek	T&D-Supv. Control	68.00	12.50	
6	Fairborn-Fairborn	T&D-Supv. Control	69.00	12.50	
7	Ft. Recovery-Minster Road, Fort Recovery	D-Monitor	69.00	12.50	
8	Garage Road-Eaton	T&D-Supv. Control	69.00	12.50	
9		T&D-Supv. Control	69.00	34.50	
10	Germantown-Germantown	D-Supv. Control	69.00	12.50	
11	Gettysburg-Gettysburg Pittsburg Rd. S. of Gettysburg	D-Supv. Control	69.00	12.50	
12	Glady Run-Lower Bellbrook Rd., S.W. of Xenia	T&D-Supv. Control	69.00	12.50	
13	Gratis-Gratis Twp., Preble Co.	D-Supv. Control	69.00	12.50	
14	Greene-Dayton-Xenia Rd., Greene Co.	T-Supv. Control	345.00	138.00	
15		T-Supv. Control	138.00	69.00	
16	Greenfield-Greenfield	T&D-Supv. Control	69.00	12.50	
17	Greenville-Greenville	T&D-Supv. Control	69.00	12.50	
18		T&D-Supv. Control	138.00	69.00	
19	Hempstead-Kettering	T&D-Supv. Control	138.00	69.00	
20		T&D-Supv. Control	69.00	12.50	
21	Honda East Liberty-Allen Twp., Union Co.	T-Supv. Control	69.00		
22	Hoover-Hoover Ave., Dayton	D-Supv. Control	69.00	12.50	
23	Huber Heights-Bellefontaine Rd., N.E. of Dayton	T&D-Supv. Control	69.00	12.50	
24	O. H. Hutchings-U.S. Rt. 25	T&D-Supv. Control	12.50	69.00	
25	S. of Miamisburg	T&D-Supv. Control	138.00	69.00	
26		T&D-Supv. Control	138.00	69.00	
27	Indian Lake-1 mi. S. of Lakeview	T&D-Supv. Control	69.00	34.50	
28		T&D-Supv. Control	69.00	12.50	
29	Jackson Center-Jackson Twp., Shelby Co.	T&D-Supv. Control	69.00	12.50	
30	Jamestown-Jamestown	T&D-Supv. Control	69.00	12.50	
31	Jeffersonville-Jeffersonville	D-Supv. Control	69.00	12.50	
32	Kettering-Dorothy Lane, Kettering	T&D-Supv. Control	69.00	12.50	
33	Killen-Adams Co.	T-Attended	23.40	345.00	
34	Kings Creek-County Rd. 126-B, N. of Urbana	T&D-Supv. Control	69.00	12.50	
35	Knollwood-Beavercreek	T&D-Supv. Control	138.00	12.50	
36	Kuther Road-Shelby Co.	D-Supv. Control	69.00	12.50	
37	Lewisburg-Harrison Twp., Preble Co.	D-Monitor	69.00	12.50	
38	Liberty-Perry Twp., Logan Co.	D-Monitor	69.00	12.50	
39					
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Logan-N.W. of West Liberty	T&D-Supv. Control	69.00	12.50	
3		T&D-Supv. Control	138.00	69.00	
4	Loramie-McLean Twp., Shelby Co.	D-Supv. Control	69.00	12.50	
5	Manning-Miamisburg	T&D-Supv. Control	69.00	12.50	
6	Martinsville-St Rt 28 E. of Martinsville	D-Supv. Control	69.00	12.50	
7	Marysville-SE of Marysville	T&D-Supv. Control	69.00	12.50	
8	McCartyville-McCartyville	D-Monitor	69.00	12.50	
9	Mechanicsburg-Goshen Twp., Champaign Co.	D-Monitor	69.00	12.50	
10	Miami-Tipp City, Miami Co.	T-Supv. Control	345.00	138.00	
11		T-Supv. Control	138.00	69.00	
12	Middleboro-Wilmington	D-Supv. Control	138.00	12.50	
13	Millcreek-Sidney	D-Supv. Control	138.00	12.50	
14	Minster-Minster	T-Monitor	69.00		
15	Monument-Dayton	T&D-Supv. Control	138.00	12.50	
16		T&D-Supv. Control	4.16	12.50	
17	Moraine-Dryden Rd., Moraine	T-Supv. Control	69.00		
18	Needmore-Webster St., Dayton	T&D-Supv. Control	138.00	12.50	
19	New Carlisle-New Carlisle	T&D-Supv. Control	138.00	69.00	
20		T&D-Supv. Control	69.00	12.50	
21	New Lebanon-New Lebanon	D-Monitor	69.00	12.50	
22	New Vienna-Highland Co.	D-Supv. Control	69.00	12.50	
23	Normandy-Spring Valley Road at Normandy Lane	D-Supv. Control	138.00	12.50	
24	Normandy-Centerville	D-Supv. Control	69.00	12.50	
25	Northlawn - Moraine	T-Supv. Control	69.00		
26	Northridge-Dayton	T&D-Supv. Control	138.00	12.50	
27	Overlook-Smithville Road, Dayton	T&D-Supv. Control	138.00	12.50	
28		T&D-Supv. Control	69.00	12.50	
29		T&D-Supv. Control	138.00	69.00	
30	Peters Rd.-Peters Road, Troy	T&D-Supv. Control	69.00	12.50	
31		T&D-Supv. Control	69.00	4.16	
32	Phoneton-Shroyer Rd. Huber Hts.	T&D-Supv. Control	69.00	12.50	
33	Piqua Sub 3-Piqua	T-Supv. Control	69.00		
34	Piqua Sub 4-Piqua	T-Supv. Control	69.00		
35	Piqua Sub 5-Piqua	T-Supv. Control	69.00		
36	Quincy-W. of Quincy	D-Monitor	138.00	12.50	
37	Robinson, S.E. of Washington C.H.	T&D-Supv. Control	69.00	12.50	
38	Rockford (New)-W. of Rockford	T&D-Monitor	69.00	12.50	
39		T&D-Monitor	69.00	34.50	
40	Rossburg-Brown Twp., Darke Co.	T&D-Supv. Control	69.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	Sabina-Sabina	D-Monitor	69.00	12.50	
3	Salem-Salem Ave., Dayton	T&D-Supv. Control	69.00	12.50	
4	Shelby-NE of Sidney	T-Supv. Control	345.00	138.00	
5	Shiloh-Elderberry Ave., Dayton	T&D-Supv. Control	69.00	12.50	
6	Sidney-Campbell Rd., Sidney	T&D-Supv. Control	138.00	69.00	
7		T&D-Supv. Control	69.00	12.50	
8		T&D-Supv. Control	4.16	12.50	
9		T&D-Supv. Control	69.00	12.50	
10	South Charleston-South Charleston	D-Supv. Control	69.00	12.50	
11	Southwestern-Fairborn	T&D Supv. Control	69.00	12.50	
12	Springcreek Springcreeek-NE of Piqua	D-Monitor	138.00	12.50	
13	St. Marys-St. Marys Twp., Auglaize Co.	T&D-Supv. Control	69.00	12.50	
14	Staunton-Miami Co.	T&D-Supv. Control	138.00	69.00	
15		T&D-Supv. Control	69.00	12.50	
16	Stillwater-Dayton	T&D-Supv. Control	69.00	12.50	
17	Sugarcreek-S. of Bellbrook	T-Supv. Control	345.00	138.00	
18	TAIT-C.T.-Moraine	T-Supv. Control	13.80	69.00	
19		T&D-Supv. Control	4.16	12.50	
20	TAIT-Dayton	T&D-Supv. Control	69.00	12.50	
21	Tipp City-Tipp City	D-Monitor	69.00	12.50	
22	Treaty-Darke Co.	D-Monitor	69.00	12.50	
23	Trebein-Trebein	T&D-Supv. Control	138.00	69.00	
24		T&D-Supv. Control	69.00	12.50	
25	Troy-Troy	T&D-Supv. Control	69.00	12.50	
26	Urbana (New)-W. of Urbana	T&D-Supv. Control	138.00	69.00	
27		T&D-Supv. Control	69.00	34.50	
28		T&D-Supv. Control	69.00	12.50	
29		T&D-Supv. Control	69.00	34.50	
30	Vandalia-Engle Rd., Vandalia	T&D-Supv. Control	69.00	12.50	
31	Washington-Wash. C.H.	T&D-Supv. Control	69.00	12.50	
32	Waynesville-Waynesville Bellbrook Rd., Waynesville	D-Supv. Control	69.00	12.50	
33	Webb Road-Clinton Co.	D-Supv. Control	69.00	12.50	
34	Webster-Dayton	T&D-Supv. Control	69.00	12.50	
35		T&D-Supv. Control	138.00	69.00	
36	West Manchester-West Manchester	T&D-Supv. Control	69.00	12.50	
37	West Milton-S.W. of West Milton	T&D-Supv. Control	345.00	138.00	
38		T&D-Supv. Control	138.00	69.00	
39		T&D-Supv. Control	69.00	12.50	
40	Wilmington-Wilmington	T&D-Supv. Control	69.00	12.50	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHOLLY OWNED SUBSTATIONS (cont'd): (1)				
2	WPAFB - Sub A	T&D-Supv. Control	69.00	12.50	
3	WPAFB - Sub B	T&D-Supv. Control	69.00	6.90	
4	WPAFB - Sub C	T&D-Supv. Control	69.00	6.90	
5		T&D-Supv. Control	69.00	12.50	
6	WPAFB - Sub D	T&D-Supv. Control	69.00	12.50	
7	WPAFB - Sub E	D-Supv. Control	69.00	6.90	
8	WPAFB - Sub F	D-Supv. Control	69.00	12.50	
9	WPAFB - Sub H	T&D-Supv. Control	69.00	12.50	
10	WPAFB - Sub J	T&D-Supv. Control	69.00	12.50	
11	WPAFB - Terminal	T-Supv. Control	69.00		
12	Wyandot-Wyandot Street, Dayton	D-Supv. Control	138.00	12.50	
13	Xenia-Xenia	T&D-Supv. Control	69.00	12.50	
14	Yankee-S.W. of Centerville	T&D-Supv. Control	12.50	69.00	
15		T&D-Supv. Control	69.00	12.50	
16	Yellow Springs-Miami Twp., Greene Co.	D-Monitor	69.00	12.50	
17	17 subs-less than 10 MVa (10)		69.00	2.40	
18	Total of Wholly Owned Substations		16288.68	4721.42	
19	COMMONLY OWNED SUBSTATIONS: (1)				
20	Beatty-Grove City (2,3)	T-Unattended	345.00		
21	Beckjord-New Richmond (2)	T-Attended	22.80	345.00	
22	Bixby-Groveport (3)	T-Unattended	345.00		
23	Conesville-Conesville (3)	T-Attended	24.50	345.00	
24	Don Marquis-Pike Co. (2)	T-Unattended	345.00		
25	Foster-Warren Co. (2)	T-Unattended	345.00		
26	Greene-Greene Co. (2)	T-Supv. Control	345.00		
27	Miami Fort-North Bend (4)	T-Attended	20.90	345.00	
28	Pierce-Clermont Co. (2)	T-Attended	345.00		
29	Port Union-Butler Co. (8)	T-Attended	345.00		
30	Stuart-Adams Co. (5)	T-Supv. Control	345.00	138.00	13.80
31	(5)	T-Monitor	22.80	345.00	
32	(6)	T-Attended	22.80	345.00	
33	(7)	T-Monitor	22.80	345.00	
34	(4)	T-Supv. Control	138.00	69.00	
35	(11)	T-Supv. Control	345.00		
36	Terminal-Cincinnati (8)	T-Attended	345.00		
37	Todhunter-Butler Co. (12)	T-Supv. Control	345.00		
38	Zimmer-Clermont Co. (9)	T-Attended	24.00	345.00	
39	Stuart-Adams Co.	T-Monitor	345.00	13.80	6.90
40	Total		4438.60	2635.80	20.70

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	COMMONLY OWNED SUBSTATIONS (cont'd.): (1)				
2	Respondent's Equivalent Share of Commonly				
3	Owned Substations				
4	Summary of Wholly Owned Substations by Function:				
5	T-Attended				
6	D-Unattended				
7	T-Supv. Control				
8	T&D-Supv. Control				
9	T&D-Monitor				
10	D-Supv. Control				
11	D-Monitor				
12	TOTAL WHOLLY OWNED AND RESPONDENT'S SHARE OF				
13	COMMONLY OWNED SUBSTATIONS				
14	Summary of Commonly Owned Substations by Function:				
15	Attended-T				
16	Supervisory Control-T				
17	Monitor-T				
18					
19					
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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
30	1					3
200	1					4
60	2					5
200	1					6
150	1					7
10	1					8
250	1					9
450	1					10
200	1	1				11
60	2					12
9	1					13
41	2					14
60	2					15
200	1					16
23	5					17
19	2					18
50	2					19
20	2					20
30	1					21
102	3					22
19	2					23
						24
60	2					25
30	1					26
250	1	1				27
45	2					28
60	2					29
22	2					30
200	1					31
30	1					32
200	1					33
40	2					34
90	3					35
70	5					36
60	2					37
30	1					38
100	2					39
						40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
150	1					2
60	2					3
60	2					4
30	1					5
60	2					6
16	2					7
60	2					8
10	1					9
21	2					10
17	2					11
40	2					12
13	1					13
896	2					14
		1				15
20	6					16
80	3					17
150	1					18
200	1					19
90	3					20
						21
83	5					22
48	2					23
490	13					24
400	2					25
		1				26
10	1					27
50	2					28
60	2					29
20	2					30
36	3					31
90	3					32
675	1					33
50	2					34
90	3					35
30	1					36
25	2					37
13	2					38
						39
						40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
18	4					2
150	1					3
19	4					4
60	2					5
19	2					6
60	2					7
13	2					8
13	1					9
450	1					10
200	1					11
13	1					12
30	1					13
						14
101	3					15
18	1					16
						17
75	2					18
150	1					19
52	2					20
26	4					21
20	1					22
30	1					23
30	1					24
						25
60	2					26
45	1					27
63	4					28
200	1					29
60	2					30
20	2					31
60	2					32
						33
						34
						35
13	1					36
60	2					37
20	1					38
10	1					39
12	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
20	2					2
60	2					3
896	2					4
60	2					5
200	1					6
60	3					7
18	1					8
		1				9
22	1					10
22	1					11
11	1					12
11	1					13
200	1					14
22	1					15
60	2					16
898	2					17
300	3					18
12	1					19
90	3					20
11	1					21
30	1					22
200	1					23
40	2					24
50	2					25
200	1					26
10	1					27
25	2					28
		1				29
82	3					30
50	2					31
25	2					32
20	1					33
103	7					34
150	1					35
24	2					36
450	1					37
200	1	1				38
40	2					39
40	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
55	2					2
25	1					3
108	3					4
25	1					5
50	2					6
25	1					7
50	2					8
50	2					9
50	2					10
						11
112	2					12
39	2					13
159	2					14
60	2					15
29	2					16
82	23					17
15414	318	7				18
						19
						20
504	1					21
						22
910	1					23
						24
						25
						26
1142	2					27
						28
						29
250	1					30
1920	3					31
900		1				32
640	1					33
100	1					34
						35
						36
						37
1955	2					38
384	4					39
8705	16	1				40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
3018	28	2				3
						4
675	1					5
3	6					6
5128	17	2				7
7874	187	3				8
261	8					9
787	37					10
469	65					11
18215	349	7				12
						13
						14
5411						15
350						16
2560						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	This Report is:	Date of Report	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 426 Line No.: 1 Column: a

(1) Located in Ohio.

(2) Certain equipment at this substation is owned by Duke Energy Ohio, Inc. (DEO), Ohio Power Company (OPCO) and the Respondent with undivided ownership of 30%, 35% and 35%, respectively. Expenses are shared on the basis of percent of ownership. The co-owners are not associated companies.

(3) Certain equipment at this substation is owned by DEO, OPCO and the Respondent with undivided ownership of 33-1/3%, 33-1/3% and 33-1/3%, respectively. Expenses are shared on the basis of percent of ownership.

(4) Certain equipment at this substation is owned by DEO and the Respondent with undivided ownership of 50% and 50%, respectively. Expenses are shared on the basis of percent of ownership.

(5) This station is owned by DEO, OPCO and the Respondent with undivided ownership of 30%, 35% and 35%, respectively. Expenses are shared on the basis of percent of ownership.

(6) Certain equipment at this substation is owned by DEO, OPCO and the Respondent with undivided ownership of 40.3%, 29.0% and 30.7%, respectively. Expenses are shared on the basis of percent of ownership.

(7) This station is owned by DEO, OPCO and the Respondent with undivided ownership of 33-1/3%, 33-1/3% and 33-1/3%, respectively. Expenses are shared on the basis of percent of ownership.

(8) Certain equipment at this substation is owned by DEO, OPCO and the Respondent with undivided ownership of 28%, 36% and 36%, respectively. Expenses are shared on the basis of percent of ownership.

(9) This station is owned by DEO, OPCO and the Respondent with undivided ownership of 28%, 36% and 36%, respectively. Expenses are shared on the basis of percent of ownership.

(10) Voltages shown reflect the highest and lowest voltages in the substations groups and not necessarily within an individual substation.

(11) Certain equipment at this substation is owned by DEO, OPCO and the Respondent with undivided ownership of 38.5%, 20.2% and 41.3%, respectively. Expenses are shared on the basis of percent of ownership.

(12) Certain equipment at this substation is owned by DEO and the Respondent with undivided ownership of 55% and 45%, respectively. Expenses are shared on the basis of percent of ownership.

Schedule Page: 426.1 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.2 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.3 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.4 Line No.: 1 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.4 Line No.: 17 Column: a

See footnote on 426, Line 1, Column a

Schedule Page: 426.4 Line No.: 19 Column: a

See footnote on 426, Line 1, Column a. This footnote pertains to Page 426.4, Lines 20-30, Column a.

Schedule Page: 426.5 Line No.: 1 Column: a

See footnote on 426.4, Line 17, Column a

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2016	End of 2015/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	Gas Purchases	DPL Energy LLC	151	5,191,378
3	Insurance Services	Miami Valley Insurance Company	924 & 925	3,205,783
4	Employee Health Insurance	AES Health & Welfare Benefit	Various	17,498,887
5	Long-Term Compensation for DP&L Employees	The AES Corporation	920	483,484
6	Services Provided by AES US Services	AES US Services LLC	Various	30,897,814
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	General & Administrative Services	DPL Energy LLC	Various	515,376
22	Supplies	Miami Valley Lighting LLC	Various	288,441
23	General & Administrative Services	Miami Valley Lighting LLC	Various	1,722,651
24	General & Administrative Services	DPL Energy Resources Inc.	Various	2,358,636
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Dayton Power and Light Company	(1) X An Original (2) __ A Resubmission	04/18/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 6 Column: d

Strategic Business Unit costs have been allocated to DP&L based on cost drivers designed to result in fair and equitable distribution.

Schedule Page: 429 Line No.: 21 Column: d

Services were provided under either a direct cost or cost allocation basis consistent with the corporate allocation policy.

Schedule Page: 429 Line No.: 23 Column: d

See footnote on 429, Line 21, Column d

Schedule Page: 429 Line No.: 24 Column: d

See footnote on 429, Line 21, Column d

Schedule	Page No.

Schedule	Page No.

Schedule — Page No.