The Dayton Power and Light Company
Case No. 13-1495-EL-UNC
Annual SEET Filing
DP&L's Calendar 2012 FERC Form 1

Exhibit GSC-2

The following pages include DP&L's calendar 2012 FERC Form 1.

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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 2012/Q4

Ernst & Young

Ernst & Young LLP
1900 Scripps Center
312 Walnut Street
Cincinnati, OH 45202

Tel: +1 513 612 1400
Fax: +1 513 612 1730
www.ey.com

Report of Independent Auditors

To the Board of Directors of The Dayton Power and Light Company:

We have audited the accompanying regulatory-basis balance sheets of The Dayton Power & Light Company as of December 31, 2012 and the related regulatory-basis statement of income, retained earnings and cash flows for the year then ended and the related notes to the regulatory financial statements, included on pages 110 through 123.57 in the Federal Energy Regulatory Commission ("FERC") Form No. 1.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with the financial reporting provisions of the Uniform System of Accounts prescribed by the FERC described in Note 1; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purposes of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of The Dayton Power & Light Company as of December 31, 2012, and its income and expenses and its cash flows for the year then ended, in accordance with the Uniform System of Accounts prescribed by the FERC described in Note 1.

ERNST & YOUNG

Report of Other Auditors on the December 31, 2011 Financial Statements

The regulatory-basis financial statements of The Dayton Power & Light Company for the year ended December 31, 2011, were audited by other auditors who expressed an unmodified opinion on those statements on April 16, 2012.

Regulatory Basis of Accounting

As described in Note 1 to the financial statements, the financial statements have been prepared by The Dayton Power & Light Company in accordance with the Uniform System of Accounts prescribed by the FERC, which is a basis of accounting other than U.S. generally accepted accounting principles to meet the requirements of the FERC. Our opinion is not modified with respect to this matter.

Restriction on Use

Our report is intended solely for the information and use of the FERC and is not intended to be and should not be used by anyone other than these specified parties.

Ernst + Young LLP

April 16, 2013

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 2012/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 Gregory S. Campbell	06 Title of Contact Person Vice President and 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* (937) 259-7861	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Gregory S. Campbell	03 Signature Gregory S. Campbell Gregory S. Campbell	04 Date Signed *(Mo, Da, Yr)* 04/17/2013
02 Title Vice President and 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.

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	/ /	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	None
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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	/ /	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

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	/ /	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	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	/ /	End of 2012/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.

Gregory S. Campbell, Vice President and 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) [X] Yes...Enter the date when such independent accountant was initially engaged: 01/01/2012
(2) [ ] 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	/ /	End of 2012/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, 2012, for additional information.

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

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	/ /	End of 2012/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	Acting CEO (1) (4) (12)	Andrew M. Vesey	
2	Senior VP and General Counsel (8)	Arthur G. Meyer	325,000
3	Senior VP, Shared Services (10)	Scott J. Kelly	290,000
4	President and Chief Executive Officer (5)	Philip R. Herrington	280,000
5	Senior VP, Competitive Market Services	Teresa F. Marrinan	265,000
6	Senior VP, Service Operations (7)	Bryce W. Nickel	250,000
7	Senior VP and General Counsel (11)	Michael S. Mizell	250,000
8	VP, Interim CFO, CAO and Controller (2)	Joseph W. Mulpas	245,000
9	Senior VP, Generation (7)	Dennis A. Lantzy	239,345
10	VP, Plant Operations (3)	Kevin W. Crawford	238,000
11	Senior VP and Chief Financial Officer (6)	Craig L. Jackson	235,000
12	VP, Assistant General Counsel and Corporate Secretary	Timothy G. Rice	221,704
13	VP, External Affairs (7)	Thomas A. Raga	185,500
14	VP and Controller (7)	Gregory S. Campbell	160,000
15	Vice President and Treasurer (9)	Jeffrey K. MacKay	146,000
16	Acting Senior VP, Human Resources and Adm (13)	Geoffrey M. Gailey	59,114
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31	(1) Appointed January 9, 2012		
32	(2) Appointed Interim CFO January 9, 2012,		
33	Resigned June 22, 2012		
34	(3) Resigned February 9, 2012		
35	(4) Resigned March 23, 2012		
36	(5) Appointed March 23, 2012		
37	(6) Appointed May 16, 2012		
38	(7) Appointed June 28, 2012		
39	(8) Retired June 30, 2012		
40	(9) Appointed August 1, 2012		
41	(10) Resigned December 14, 2012		
42	(11) Appointed December 17, 2012		
43	(12) Employed by Affiliated Company		
44	(13) Salary is DP&L's share		

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	/ /	End of 2012/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Andrew M. Vesey [Chairman of Board] (3)	Arlington, Virginia
2		
3	Bernerd R. DaSantos (5)	Arlington, Virginia
4		
5	Elizabeth Hackenson (6)	Arlington, Virginia
6		
7	Victoria D. Harker (4)	Arlington, Virginia
8		
9	Philip R. Herrington (2)	Dayton, Ohio
10		
11	William C. Hoagland, III (6)	Arlington, Virginia
12		
13	Vincent W. Mathis	Arlington, Virginia
14		
15	Brian A. Miller	Arlington, Virginia
16		
17	Thomas M. O'Flynn (6)	Arlington, Virginia
18		
19	Richard Santoroski (1)	Arlington, Virginia
20		
21	Britaldo P. Soares	Sao Paulo, Brazil
22		
23	Gardner W. Walkup (5)	Arlington, Virginia
24		
25	Kenneth J. Zagzebski	Indianapolis, Indiana
26		
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43	(1) Resigned February 29, 2012	
44	(2) Elected March 23, 2012	
45	(3) Elected Chairman March 23, 2012	
46	(4) Resigned April 30, 2012	
47	(5) Not re-elected February 25, 2013	
48	(6) Elected February 25, 2013	

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	/ /	End of 2012/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	/ /	End of 2012/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				
5	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	/ /	End of 2012/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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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	/ /	End of 2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.
1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on 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.

1. None

2. None

3. None

4. None

5. None

6. DP&L has access to $400 million of short-term financing under two revolving credit facilities. The first facility, established in August 2011, is for $200 million and expires in August 2015 and has eight participating banks, with no bank having more than 22% of the total commitment. DP&L also has the option to increase the borrowing under the first facility by $50 million. The DP&L transaction was initially authorized by an Order of the Public Utilities Commission of Ohio dated December 15, 2010 under Case No. 10-2629-EL-AIS. The second facility, established in April 2010, is for $200 million and expires in April 2013. A total of five banks participate in this facility, with no bank having more than 35% of the total commitment. Each DP&L revolving credit facility has a $50 million letter of credit sublimit. As of December 31, 2012, DP&L had no outstanding borrowings of the available commitment and no outstanding letters of credit against these revolving credit facilities. This transaction was initially authorized by an Order of the Public Utilities Commission of Ohio dated December 9, 2009 under Case No. 09-1803-EL-AIS.

   DPL established a $125 million revolving credit facility in August 2011. The size of the facility was reduced from $125.0 million to $75.0 million as part of an amendment dated October 19, 2012 that was negotiated between DPL and the syndicated bank group. This facility expires in August 2014, and has seven participating banks, with no bank having more than 32% of the total commitment. The DPL revolving credit facility had $125 letter of credit sublimit, however, on October 19, 2012, DPL and the syndicated bank group approved an amendment which reduced the size of the facility from $125.0 million to $75 million and modified certain covenants in the facility.

   In addition, DPL entered into a $425 million unsecured term loan agreement with a syndicated bank group in August 2011. This agreement is for a three year term expiring on August 24, 2014. DPL used the proceeds from a $300 million drawdown of this facility to redeem $297.4 million of 6.875% senior unsecured notes.

7. None

8. The employees covered under our collective bargaining agreement ratified a new three year contract on November 2, 2011. The annual impact of the wage increase was approximately $2.0 million for 2012. The collective bargaining agreement expires on October 31, 2014.

9. In September 2002, DP&L and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, DP&L and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, DP&L received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to DP&L's service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. DP&L granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against DP&L and numerous other defendants alleging that DP&L and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against DP&L that related to allegations that chemicals used by DP&L at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous

substances from DP&L that were allegedly directly delivered by truck to the landfill. Thereafter, discovery, including depositions of past and present DP&L employees occurred. In June 2012, DP&L filed a motion for summary judgment on grounds that the remaining claims for contribution were barred by a statute of limitations. The plaintiffs opposed that motion and, additionally, filed a motion seeking Court leave to amend their complaint to add more than 20 new defendants to the case and to re-characterize and re-allege claims against DP&L that the Court dismissed in its February 10, 2011 order. On October 26, 2012, DP&L received another request to access DP&L's service center building site to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. DP&L is complying with this sampling request. On February 8, 2013, the Court granted DP&L's motion for summary judgment on statute of limitations grounds with respect to claims seeking a contribution toward the costs that are expected to be incurred by PRP group in their performing a RI/FS. The Court's ruling is likely to be appealed. Additionally, the Court's ruling does not address future litigation that may arise with respect to actual remediation costs.

On October 5, 2012, DP&L filed an ESP with the PUCO to establish SSO rates that were to be in effect starting January 2013. The plan was re-filed on December 12, 2012 to correct for certain projected costs. The plan requested approval of a non-bypassable charge that is designed to recover $137.5 million per year for five years from all customers. DP&L also requested approval of a switching tracker that would measure the incremental amount of switching over a base case and defer the lost value into a regulatory asset which would be recovered from all customers beginning January 2014. The ESP states that DP&L plans to file on or before December 31, 2013 its plan for legal separation of its generation assets. The ESP proposes a three year and five month transition to market, whereby a wholesale competitive bidding structure will be phased in to supply generation service to SSO customers. The PUCO is currently reviewing the filing and an evidentiary hearing began on March 18, 2013. The PUCO authorized that the rates being collected prior to December 31, 2012 would continue until the new ESP rates go into effect.

10. None

11. None

12. None

13. On November 9, 2012, DPL Inc. and DP&L announced the appointment of Michael S. Mizell as Sr. Vice President and General Counsel for DPL Inc. and DP&L effective December 13, 2012.

    On February 25, 2013, DPL Inc. appointed and/or re-appointed the following individuals as directors of DP&L for 2013 or until their successor are elected and qualified:

    Willard C. Hoagland, III, Elizabeth Hackenson, Philip R. Herrington, Vincent W. Mathis, Brian A. Miller, Britaldo Pedrosa Soares, Andrew M. Vesey, Thomas M. O'Flynn, and Kenneth J. Zagzebski.

14. None

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	/ /	End of 2012/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,243,173,518	5,271,768,021
3	Construction Work in Progress (107)	200-201	87,829,512	150,703,437
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,331,003,030	5,422,471,458
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,627,331,036	2,680,278,087
6	Net Utility Plant (Enter Total of line 4 less 5)		2,703,671,994	2,742,193,371
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)		2,703,671,994	2,742,193,371
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,716,992	5,072,058
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	11,317,139
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		3,615,103	1,495,919
31	Long-Term Portion of Derivative Assets – Hedges (176)		479,472	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		9,401,839	18,375,116
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		28,548,696	32,246,686
36	Special Deposits (132-134)		20,692,299	4,607,691
37	Working Fund (135)		12,151	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		72,640,336	88,401,550
41	Other Accounts Receivable (143)		22,194,261	31,679,045
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		922,714	941,172
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		18,674,599	9,833,606
45	Fuel Stock (151)	227	65,585,127	80,947,408
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	50,353,809	46,937,102
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	53,069	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	/ /	End of 2012/Q4

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	1,881,095	1,740,663
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)		10,863,203	13,015,264
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)		48,090,174	49,521,137
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		6,912,325	2,547,930
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		3,615,103	1,495,919
65	Derivative Instrument Assets - Hedges (176)		959,144	605,680
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		479,472	0
67	Total Current and Accrued Assets (Lines 34 through 66)		342,442,999	359,646,671
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		6,473,631	6,814,635
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	193,279,588	184,790,407
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)		1,101,317	1,772,010
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	83,139,057	88,578,044
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)		11,916,329	12,975,654
82	Accumulated Deferred Income Taxes (190)	234	50,311,926	64,136,124
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		346,221,848	359,066,874
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,401,738,680	3,479,282,032

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	/ /	end of 2012/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	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)		303,991,819	303,991,820
7	Other Paid-In Capital (208-211)	253	515,956,712	515,794,822
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	534,216,614	589,121,233
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)	-38,698,929	-34,718,529
16	Total Proprietary Capital (lines 2 through 15)		1,322,011,847	1,380,734,977
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	884,375,000	884,375,000
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	18,481,738	18,597,872
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		136,417	318,308
24	Total Long-Term Debt (lines 18 through 23)		902,720,321	902,654,564
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		117,602	377,766
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,821,600	4,721,600
29	Accumulated Provision for Pensions and Benefits (228.3)		72,412,739	58,525,739
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		733,875	1,364,416
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		1,500,438	2,518,054
34	Asset Retirement Obligations (230)		19,210,204	18,824,765
35	Total Other Noncurrent Liabilities (lines 26 through 34)		97,796,458	86,332,340
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		79,063,177	106,045,481
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		35,193,550	15,804,632
42	Taxes Accrued (236)	262-263	158,157,727	166,690,073
43	Interest Accrued (237)		13,054,750	7,874,423
44	Dividends Declared (238)		72,232	72,232
45	Matured Long-Term Debt (239)		0	0

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The Dayton Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/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)		48,318,439	50,615,120
49	Obligations Under Capital Leases-Current (243)		285,091	297,841
50	Derivative Instrument Liabilities (244)		3,520,022	5,859,965
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		733,875	1,364,416
52	Derivative Instrument Liabilities - Hedges (245)		8,171,594	1,121,035
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		1,500,438	2,518,054
54	Total Current and Accrued Liabilities (lines 37 through 53)		343,602,269	350,498,332
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,114,277	2,523,161
57	Accumulated Deferred Investment Tax Credits (255)	266-267	27,384,675	29,890,167
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	136,789	17,910,571
60	Other Regulatory Liabilities (254)	278	6,665,801	8,386,600
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)		645,879,773	645,427,779
64	Accum. Deferred Income Taxes-Other (283)		54,426,470	54,923,541
65	Total Deferred Credits (lines 56 through 64)		735,607,785	759,061,819
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,401,738,680	3,479,282,032

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	/ /	End of 2012/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

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	1,566,393,484	1,741,894,070		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	927,343,008	1,024,193,337		
5	Maintenance Expenses (402)	320-323	107,494,081	116,953,378		
6	Depreciation Expense (403)	336-337	214,735,856	130,892,543		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	354,739	451,613		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,043,016	2,705,250		
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	124,947,187	129,645,792		
15	Income Taxes - Federal (409.1)	262-263	52,251,743	54,898,613		
16	- Other (409.1)	262-263	1,008,725	927,257		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	4,455,621	50,852,514		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,505,492	-2,506,448		
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)		-510	869		
23	Losses from Disposition of Allowances (411.9)		-1,038	53,585		
24	Accretion Expense (411.10)		916,254	848,021		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,437,044,210	1,509,914,586		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		129,349,274	231,979,484		

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	/ /	End of 2012/Q4

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		
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)	Line No.
1,566,393,484	1,741,894,070					1
						2
927,343,008	1,024,193,337					3
107,494,081	116,953,378					4
214,735,856	130,892,543					5
354,739	451,613					6
6,043,016	2,705,250					7
						8
						9
						10
						11
						12
124,947,187	129,645,792					13
52,251,743	54,898,613					14
1,008,725	927,257					15
4,455,621	50,852,514					16
						17
-2,505,492	-2,506,448					18
						19
						20
-510	869					21
-1,038	53,585					22
916,254	848,021					23
1,437,044,210	1,509,914,586					24
129,349,274	231,979,484					25
						26

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	/ /	End of 2012/Q4

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)		129,349,274	231,979,484		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		2,184,764	1,797,662		
38	Allowance for Other Funds Used During Construction (419.1)		2,051,975	2,276,067		
39	Miscellaneous Nonoperating Income (421)		39,928,315	37,407,341		
40	Gain on Disposition of Property (421.1)			7,826		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		44,165,054	41,488,896		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		192,161			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		807,477	1,148,301		
46	Life Insurance (426.2)					
47	Penalties (426.3)		280,000			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		312,468	335,674		
49	Other Deductions (426.5)		40,147,842	38,673,581		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		41,739,948	40,157,556		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	372,000	372,000		
53	Income Taxes-Federal (409.2)	262-263		-645,513		
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	-64,908			
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)		436,908	-273,513		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,988,198	1,604,853		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		39,756,218	38,938,849		
63	Amort. of Debt Disc. and Expense (428)		957,680	877,289		
64	Amortization of Loss on Reaquired Debt (428.1)		1,059,325	1,333,860		
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)		345,451	1,394,755		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,903,431	2,175,386		
70	Net Interest Charges (Total of lines 62 thru 69)		40,215,243	40,369,367		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		91,122,229	193,214,970		
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)		91,122,229	193,214,970		

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	/ /	End of 2012/Q4

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		589,121,233	616,934,934
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4			-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)		91,122,229	193,214,970
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		-864,958	(866,781)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-864,958	(866,781)
30	Dividends Declared-Common Stock (Account 438)			
31			-145,000,000	(220,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-145,000,000	(220,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		534,216,614	589,121,233
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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	/ /	End of 2012/Q4

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)
39				
40				
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)		534,216,614	589,121,233
	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)			

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	/ /	End of 2012/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See 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)	91,122,229	193,214,970
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	141,268,487	134,897,428
5	Taxes Applicable to Subsequent Years	5,200,012	-9,035,968
6	Prepaid Taxes	102,337	8,097,500
7	Pension and Retire Benefits	28,451,817	-24,036,993
8	Deferred Income Taxes (Net)	3,556,161	50,744,696
9	Investment Tax Credit Adjustment (Net)	-2,505,492	-2,506,448
10	Net (Increase) Decrease in Receivables	29,731,331	7,459,847
11	Net (Increase) Decrease in Inventory	14,243,687	-11,791,641
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-18,612,042	22,436,667
14	Net (Increase) Decrease in Other Regulatory Assets	-1,549,166	-2,654,296
15	Net Increase (Decrease) in Other Regulatory Liabilities	303,260	-9,993,620
16	(Less) Allowance for Other Funds Used During Construction	2,051,975	2,276,067
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	80,781,378	
19	Net (Increase) Decrease in Receivables/Payable from/to Parent	-8,840,993	-2,205,339
20	Other (Deferred Debits)	-21,450,939	38,672,323
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	339,750,092	391,023,059
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-180,638,500	-207,638,474
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):	-5,522,298	-4,601,025
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-186,160,798	-212,239,499
35			
36	Acquisition of Other Noncurrent Assets (d)	160,391	
37	Proceeds from Disposal of Noncurrent Assets (d)		
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)		

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	/ /	End of 2012/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See 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	2,941,234	-3,785,410
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	-14,815,967	3,169,722
53	Other (provide details in footnote):	408,150	1,019,157
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-197,466,990	-211,836,030
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
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):		20,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)		20,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-116,134	-93,127
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-864,958	-866,781
81	Dividends on Common Stock	-145,000,000	-220,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-145,981,092	-200,959,908
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-3,697,990	-21,772,879
87			
88	Cash and Cash Equivalents at Beginning of Period	32,246,686	54,019,565
89			
90	Cash and Cash Equivalents at End of period	28,548,696	32,246,686

Schedule Page: 120 Line No.: 18 Column: b
Fixed Asset Impairment

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: c
Represents investing activity related to DP&L's Master Trust

Schedule Page: 120 Line No.: 57 Column: b
Proceeds on sale of land

Schedule Page: 120 Line No.: 67 Column: c
Contribution from parent

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	/ /	End of 2012/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to 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.

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTU	British Thermal Units
CFTC	Commodity Futures Trading Commission
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
CO2	Carbon Dioxide
CCEM	Customer Conservation and Energy Management
CRES	Competitive Retail Electric Service
DPL	DPL Inc.
DPLE	DPL Energy, LLC, a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
DPLER	DPL Energy Resources, Inc., a wholly-owned subsidiary of DPL which sells competitive electric energy and other energy services
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
DUKE ENERGY	Duke Energy Ohio, Inc., formerly The Cincinnati Gas & Electric Company (CG&E)
EIR	Environmental Investment Rider
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan: a cost-based plan that a utility may file with the PUCO to establish SSO rates pursuant to Ohio law
2009 ESP STIPULATION	A Stipulation and Recommendation filed by DP&L with the PUCO on February 24, 2009 regarding DP&L's ESP filing pursuant to SB 221. The Stipulation was signed by the Staff of the PUCO, the Office of the Ohio Consumers' Counsel and various intervening parties. The PUCO approved the Stipulation on June 24, 2009.
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
FTRs	Financial Transmission Rights

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
kWh	Kilowatt hour
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.
MC SQUARED	MC Squared Energy Services, LLC, a retail electricity supplier wholly-owned by DPLER which was purchased by DPLER on February 28, 2011
MERGER	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of the Merger agreement. At the Merger date, Dolphin Sub, Inc. was merged into DPL, leaving DPL as the surviving company. As a result of the Merger, DPL became a wholly-owned subsidiary of AES.
MERGER AGREEMENT	The Agreement and Plan of Merger dated April 19, 2011 among DPL, AES and Dolphin Sub, Inc., a wholly-owned subsidiary of AES, whereby AES agreed to acquire DPL for $30 per share in a cash transaction valued at approximately $3.5 billion plus the assumption of $1.2 billion of existing debt. Upon closing, 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., a wholly-owned subsidiary of AES.
MISO	Midwest Independent Transmission System Operator, Inc., a regional transmission organization
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
NERC	North American Electric Reliability Corporation
NON-BYPASSABLE	Charges that are assessed to all customers regardless of whom the customer selects to supply its retail electric service
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review – a preconstruction permitting program regulating new or significantly modified sources of air pollution
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
OCC	Ohio Consumers' Counsel
ODT	Ohio Department of Taxation

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
OHIO EPA	Ohio Environmental Protection Agency
OHIO POWER	Ohio Power Company, 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.
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, a regional transmission organization
PREDECESSOR	DPL prior to November 28, 2011, the date AES acquired DPL.
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RPM	The Reliability Pricing Model is PJM's capacity construct. The purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. Under the RPM construct, PJM procures capacity, through a multi-auction structure, on behalf of the load serving entities to satisfy the load obligations. There are three RPM 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 then 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.
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SB 221	Ohio Senate Bill 221, 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.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SEET	Significantly Excessive Earnings Test
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SO2	Sulfur Dioxide
SO3	Sulfur Trioxide
SSO	Standard Service Offer which represents the regulated rates, authorized by the PUCO, charged to retail customers within DP&L's service territory.
SUCCESSOR	DPL after its acquisition by AES.
TCRR	Transmission Cost Recovery Rider
USEPA	U.S. Environmental Protection Agency
USF	Universal Service Fund
VRDN	Variable Rate Demand Note

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 Notes to Financial Statements below have been prepared in accordance with GAAP and may appear in The Dayton Power and Light Company Annual Report on Form 10-K for the year ended December 31, 2012. 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.

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. DP&L is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and the wholesale sales of power to its DPLER and MC Squared affiliates in Ohio and Illinois. Electricity for DP&L's 24 county service area is primarily generated at eight coal-fired electric generating stations and is distributed to more than 513,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. DP&L is a wholly-owned subsidiary of DPL. The terms "we," "us," "our" and "ours" are used to refer to DP&L.

On November 28, 2011, DP&L's parent company DPL was acquired by AES in the Merger and DPL became a wholly-owned subsidiary of AES. See Note 2 for more information. Following the Merger of DPL and Dolphin Subsidiary II, Inc., DPL became an indirectly wholly-owned subsidiary of AES.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. DP&L sells any excess energy and capacity into the wholesale market.

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 1,428 people as of December 31, 2012. Approximately 52% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

Financial Statement Presentation

DP&L does not have any subsidiaries. DP&L has undivided ownership interests in seven 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.

Deferred SECA revenue of $17.8 million at December 31, 2011 was reclassified from Regulatory liabilities to Other deferred credits. The FERC-approved SECA billings were unearned revenue where the earnings process was not complete. On July 5, 2012, a Stipulation was executed and filed with the FERC that resolved SECA claims against BP Energy Company ("BP") and DP&L, AEP (and its subsidiaries) and Exelon Corporation (and its subsidiaries). On October 1, 2012, DP&L received $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012, there is no remaining balance in Other deferred credits related to SECA. See Note 14 for more information relating to SECA.

Certain immaterial amounts from prior periods, including derivative assets and liabilities and restricted cash, have been reclassified to conform to the current period presentation.

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 results 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. These power sales and purchases are reported on a net hourly basis as revenues or purchased power on our statements of results 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.

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. Property, plant and equipment 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 $4.0 million, $4.4 million and $3.4 million for the years ended December 31, 2012, 2011 and 2010, 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.

At December 31, 2012, DP&L did not have any material plant acquisition adjustments or other plant-related adjustments.

Repairs and Maintenance
Costs associated with maintenance activities, primarily 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 – Changes in Estimates
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.

In the third quarter of 2012, a series of events led DP&L management to conclude that there was an impairment in the value of certain generating stations (see Note 15 for more information). The effect of this impairment will be to reduce future depreciation related to these stations by approximately $7.1 million per year. The effect in the year ended December 31, 2012 was a reduction of approximately $1.8 million.

In July 2010, DP&L completed a depreciation rate study for non-regulated generation property based on its property, plant and equipment balances at December 31, 2009, with certain adjustments for subsequent property additions. The results of the depreciation study concluded that many of DP&L's composite depreciation rates should be reduced due to projected useful asset lives which are longer than those previously estimated. DP&L adjusted the depreciation rates for its non-regulated generation property effective July 1, 2010, resulting in a net reduction of depreciation expense. During the year ended December 31, 2011, the net reduction in depreciation expense amounted to $3.4 million ($2.2 million net of tax) compared to the prior year. On an annualized basis going forward, the net reduction in depreciation expense is projected to be approximately $6.8 million ($4.4 million net of tax).

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 4.2% in 2012, 2.5% in 2011 and 2.6% in 2010.

The following is a summary of DP&L's Property, plant and equipment with corresponding composite depreciation rates at December 31, 2012 and December 31, 2011:

	At December 31,			
$ in millions	2012	Composite Rate	2011	Composite Rate
Regulated:				
Transmission	$ **380.9**	**2.4%**	$ 367.5	2.4%
Distribution	**1,480.7**	**3.4%**	1,371.5	3.4%
General	**100.0**	**5.4%**	84.8	4.1%
Non-depreciable	**60.1**	**N/A**	59.7	N/A
Total regulated	**2,021.7**		1,883.5	
Unregulated:				
Production / Generation	**3,210.8**	**4.9%**	3,377.9	2.2%
Non-depreciable	**16.5**	**N/A**	16.5	N/A
Total unregulated	**3,227.3**		3,394.4	
Total property, plant and equipment in service	$ **5,249.0**	**4.2%**	$ 5,277.9	2.5%

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 associated with the retirement of our long-lived assets consisted 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 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.

Changes in the Liability for Generation AROs

$ in millions		
Year ended December 31, 2011		
Balance at January 1, 2011	$	17.5
Accretion expense		0.8
Additions		-
Settlements		(0.5)
Estimated cash flow revisions		1.0
Balance at December 31, 2011		18.8
Year ended December 31, 2012		
Accretion expense		0.9
Additions		-
Settlements		(0.4)
Estimated cash flow revisions		(0.1)
Balance at December 31, 2012	$	19.2

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 $112.1 million and $112.4 million in estimated costs of removal at December 31, 2012 and 2011, 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 4.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Year ended December 31, 2011		
Balance at January 1, 2011	$	107.9
Additions		9.4
Settlements		(4.9)
Balance at December 31, 2011		112.4
Year ended December 31, 2012		
Additions		10.1
Settlements		(10.4)
Balance at December 31, 2012	$	112.1

Regulatory Accounting
In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and Regulatory liabilities represent current recovery of expected future costs.
We evaluate our Regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator. If we were required to terminate application of these GAAP provisions for all of our regulated operations, we would have to write off the amounts of all regulatory assets and liabilities to the statements of results of operations at that time. See Note 4.

Effective December 31, 2011, Regulatory assets and Liabilities are presented on a current and non-current basis, depending on the term recovery is anticipated. This change was made to conform with AES' presentation of Regulatory assets and liabilities.

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 consist of 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. Beginning in January 2010, part of the gains on emission allowances were used to reduce the overall fuel rider charged to our SSO retail customers. Emission allowances are amortized as they are used in our operations. Renewable energy credits are amortized as they are used or retired.

Prior to the Merger date, emission allowances and renewable energy credits were carried as inventory. Emission allowances and renewable energy credits are now carried as intangibles in accordance with AES' policy.

Income Taxes
GAAP requires an asset and liability approach for financial accounting and reporting of income taxes with tax effects of differences, based on currently enacted income tax rates, between the financial reporting and tax basis of accounting reported as deferred tax assets or liabilities in the balance sheets. Deferred tax assets are recognized for deductible temporary differences. Valuation allowances are provided against deferred tax assets unless it is more likely than not that the asset will be realized.

Investment tax credits, which have been used to reduce federal income taxes payable, are deferred for financial reporting purposes and are amortized over the useful lives of the property to which they relate. For rate-regulated operations, additional deferred income taxes and offsetting regulatory assets or liabilities are recorded to recognize that income taxes will be recoverable or refundable through future revenues.

As a result of the Merger, DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, DPL and its subsidiaries filed a consolidated U.S. federal income tax return. 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 7 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 basis for public equity security and fixed maturity investments is 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 are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Results of Operations in accordance with AES policy. The amounts for the years ended December 31, 2012, 2011 and 2010 were $50.5 million, $53.7 million and $51.7 million, respectively.

Share-Based Compensation
We measure the cost of employee services received and paid with equity instruments based on the fair value of such equity instrument on the grant date. This cost is recognized in results of operations over the period that employees are required to provide service. Liability awards are initially recorded based on the fair value of equity instruments and are to be re-measured for the change in stock price at each subsequent reporting date until the liability is ultimately settled. The fair value for employee share options and other similar instruments at the grant date are estimated using option-pricing models and any excess tax benefits are recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits is presented in the statements of cash flows within Cash flows from financing activities. See Note 11 for additional information. As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2012 or 2011.

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 include restrictions imposed by agreements related to deposits held as collateral.

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 they are designated as a cash flow hedge of a forecasted transaction or qualify 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 and MTM accounting when the hedge or a portion of the hedge is not effective. 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 10 for additional information.

Following the acquisition of DPL in November 2011 by AES, DPL began presenting its derivative positions on a gross basis in accordance with AES policy. This change has been reflected in the 2011 balance sheet contained in these statements.

Insurance and Claims Costs
In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of DPL, provides insurance coverage to DP&L and, in some cases, our partners in commonly owned facilities we operate, for workers' compensation, general liability, property damage, and directors' and officers' liability. DP&L is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, DP&L has estimated liabilities for medical, life, and disability claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $17.7 million and $18.9 million for 2012 and 2011, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for workers' compensation, medical, life and disability at DP&L are actuarially determined based on a reasonable estimation of insured events occurring. 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.

Related Party Transactions
In the normal course of business, DP&L enters into transactions with other subsidiaries of DPL. All material intercompany accounts and transactions are eliminated in DPL's Consolidated Financial Statements. The following table provides a summary of these transactions:

$ in millions	Years ended December 31, 2012	2011	2010
DP&L revenues:			
Sales to DPLER (a)	$ 350.8	$ 327.0	$ 238.5
Sales to MC Squared	$ 40.0	$ -	$ -
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC (b)	$ (2.6)	$ (3.1)	$ (3.3)
Expense recoveries for services provided to DPLER (c)	$ 4.0	$ 4.6	$ 5.8
DP&L Customer security deposits:			
Deposits received from DPLER (d)	$ 20.2	$ -	$ -

(a) DP&L sells 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. The increase in DP&L's sales to DPLER during the year ended December 31, 2012, compared to the year ended December 31, 2011 is primarily due to customers electing to switch their generation service from DP&L to DPLER. DP&L started selling physical power to MC Squared during June 2012 and became their sole source of power in September 2012.

(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.

Recently Adopted Accounting Standards

Fair Value Disclosures
In May 2011, the FASB issued ASU 2011-04 "Fair Value Measurements" (ASU 2011-04) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 820, "Fair Value Measurements." ASU 2011-04 essentially converges US GAAP guidance on fair value with the IFRS guidance. The ASU requires more disclosures around Level 3 inputs. It also increases reporting for financial instruments disclosed at fair value but not recorded at fair value and provides clarification of blockage factors and other premiums and discounts. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Comprehensive Income
In June 2011, the FASB issued ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 220, "Comprehensive Income." ASU 2011-05 essentially converges US GAAP guidance on the presentation of comprehensive income with the IFRS guidance. The ASU requires the presentation of comprehensive income in one continuous financial statement or two separate but consecutive statements. Any reclassification adjustments from other comprehensive income to net income are required to be presented on the face of the Statement of Comprehensive Income. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Goodwill Impairment
In September 2011, the FASB issued ASU 2011-08 "Testing Goodwill for Impairment" (ASU 2011-08) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC Topic 350, "Intangibles-Goodwill and Other." ASU 2011-08 allows an entity to first test goodwill using qualitative factors to determine if it is more likely than not that the fair value of a reporting unit has been impaired, if so, then the two-step impairment test is performed. DP&L does not have any goodwill.

Recently Issued Accounting Standards
The FASB recently issued ASU 2013-01, "Scope Clarification of Disclosures about Offsetting Assets and Liabilities", to limit the scope of ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" to derivatives (including bifurcated embedded derivatives), repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions. This ASU is effective for annual and interim periods beginning on or after January 1, 2013. The FASB clarified that the disclosures were not intended to included trade receivables and other contracts for financial instruments that may be subject to a master netting arrangement. This new rule is not expected to have a material effect on our overall results of operations, financial position or cash flows.

The FASB recently issued ASU 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income" effective for annual and interim periods beginning after December 15, 2012. The ASU does not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This new rule is not expected to have a material effect on our overall results of operations, financial position or cash flows.

2. Business Combination

On November 28, 2011, all of the outstanding common stock of DP&L's parent company, DPL, was acquired by AES. In accordance with FASC 805, the assets and liabilities of DPL were valued at their fair value at the Merger date. These adjustments were "pushed down" to DPL's records. These adjustments were not pushed down to DP&L which will continue to present its assets and liabilities on its historical cost basis. Therefore, DP&L does not need to show a Predecessor and Successor split of its financial statements.

3. Supplemental Financial Information

$ in millions		December 31, 2012		2011
Accounts receivable, net				
Unbilled revenue	**$**	**48.1**	$	49.5
Customer receivables		**62.0**		85.8
Amounts due from partners in jointly-owned stations		**19.7**		29.2
Coal sales		**1.6**		1.0
Other		**29.5**		13.9
Provisions for uncollectible accounts		**(0.9)**		(0.9)
Total accounts receivable, net	**$**	**160.0**	$	178.5
Inventories				
Fuel and limestone	**$**	**67.3**	$	82.8
Plant materials and supplies		**39.8**		38.6
Other		**1.8**		1.7
Total inventories, at average cost	**$**	**108.9**	$	123.1

Accumulated Other Comprehensive Income (Loss)

AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at December 31, 2012 and 2011:

$ in millions (net of tax)		December 31, 2012		2011
Financial instruments	**$**	**1.0**	$	0.6
Cash flow hedges		**2.6**		9.0
Pension and postretirement benefits		**(42.3)**		(44.3)
Total	**$**	**(38.7)**	$	(34.7)

4. Regulatory Matters

In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of recovery being reflected in future rates.

We evaluate our regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities for DP&L are as follows:

$ in millions	Type of Recovery(a)	Amortization Through	December 31, 2012	December 31, 2011
Regulatory assets, current:				
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	$ 7.0	$ 4.7
Power plant emission fees	C	Ongoing	-	4.8
Fuel and purchased power recovery costs	C	Ongoing	11.3	8.2
Total regulatory assets, current			$ 18.3	$ 17.7
Regulatory assets, non-current:				
Deferred recoverable income taxes	B/C	Ongoing	$ 35.1	$ 24.1
Pension benefits	C	Ongoing	88.9	92.1
Unamortized loss on reacquired debt	C	Ongoing	11.9	13.0
Regional transmission organization costs	D	2014	2.6	4.1
Deferred storm costs	D		24.4	17.9
CCEM smart grid and advanced metering infrastructure costs	D		6.6	6.6
CCEM energy efficiency program costs	F	Ongoing	5.2	8.8
Consumer education campaign	D		3.0	3.0
Retail settlement system costs	D		3.1	3.1
Other costs			4.7	5.1
Total regulatory assets, non-current			$ 185.5	$ 177.8
Regulatory liabilities, current:				
Fuel and purchased power recovery costs	C	Ongoing	$ 0.1	$ -
Total regulatory liabilities, current			$ 0.1	$ -
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			$ 112.1	$ 112.4
Postretirement benefits			5.0	6.2
Other			0.2	-
Total regulatory liabilities, non-current			$ 117.3	$ 118.6

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

Regulatory Assets

TCRR, transmission, ancillary and other PJM-related 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.

Power plant emission fees represent costs paid to the State of Ohio since 2002. As part of the fuel factor settlement agreement in November 2011, these costs are being recovered through the fuel factor.

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. DP&L implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. We received the audit report for 2011 on April 27, 2012. The auditor has recommended that the PUCO consider reducing DP&L's recovery of fuel costs by approximately $3.4 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow through items as the result of amounts 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.

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 other comprehensive income (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.

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

Regional transmission organization costs represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case.

Deferred storm costs relate to costs incurred to repair the damage caused by storms in the following years:

- 2008 – related to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other 2008 storms. On January 14, 2009, the PUCO granted DP&L the authority to defer these costs with a return until such time that DP&L seeks recovery in a future rate proceeding.
- 2011 – related to five major storms in 2011. On December 21, 2012, DP&L filed a request with the PUCO for an accounting order to defer costs and a request for recovery of costs associated with these storms. DP&L believes the recovery of these costs is probable at December 31, 2012.
- 2012 – related to storm damage that occurred during final weekend of June 2012. On August 10, 2012, DP&L filed a request with the PUCO, which was modified on October 19, 2012, for an accounting order to defer the costs associated with this storm damage. On December 19, 2012, the PUCO issued an order permitting partial deferral.

On December 21, 2012, DP&L filed a request for recovery of all of these deferred storm costs with the PUCO.

CCEM smart grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and 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. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider that began July 1, 2009 and that is subject to a two-year true-up for any over/under recovery of costs. The two-year true-up was approved by the PUCO and a new rate was set.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation and its related rate case. DP&L will be seeking recovery of these costs as part of our next distribution rate case filing at the PUCO. The timing of such a filing has not yet been determined.

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. Based on case precedent in other utilities' cases, the costs are recoverable through DP&L's next transmission rate case.

Other costs primarily include RPM capacity, other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities

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. DP&L implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. We received the audit report for 2011 on April 27, 2012. The auditor has recommended that the PUCO consider reducing DP&L's recovery of fuel costs by approximately $3.4 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

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.

5. Ownership of Coal-fired Facilities

DP&L and certain other Ohio utilities have undivided ownership interests in seven 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. As of December 31, 2012, DP&L had $36.0 million of construction work in process at such facilities. DP&L's share of the operating cost of such facilities is included within the corresponding line in the Statements of Results 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.

DP&L's undivided ownership interest in such facilities as well as our wholly-owned coal fired Hutchings Station at December 31, 2012, is as follows:

	DP&L Share		DP&L Investment			
	Ownership %	Summer Production Capacity (MW)	Gross Plant in Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and in Service (Yes/No)
Jointly-owned production units						
Beckjord Unit 6	50.0	207	$ 76	$ 64	$ -	No
Conesville Unit 4	16.5	129	18	1	11	Yes
East Bend Station	31.0	186	208	136	3	Yes
Killen Station	67.0	402	617	299	5	Yes
Miami Fort Units 7 and 8	36.0	368	363	147	3	Yes
Stuart Station	35.0	808	744	294	12	Yes
Zimmer Station	28.1	365	1,099	642	2	Yes
Transmission (at varying percentages)			96	59	-	
Total		2,465	$ 3,221	$ 1,642	$ 36	
Wholly-owned production unit						
Hutchings Station	100.0	365	$ -	$ -	$ -	No

Currently, our coal-fired electric generation units at Hutchings and Beckjord do not have the SCR and FGD emission-control equipment installed. DP&L owns 100% of the Hutchings Station and has a 50% interest in Beckjord Unit 6. On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our commonly owned Unit 6, in December 2014. This was followed by a notification by the joint owners of Beckjord Unit 6 to PJM, dated April 12, 2012, of a planned June 1, 2015 deactivation of this unit. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision.

DP&L has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated June 1, 2013. In addition, DP&L has notified PJM that the remaining units at Hutchings will no longer operate after May 2013 and will be deactivated on June 1, 2015. The decision to deactivate these units has been made because these units are not equipped with the advanced environmental control technologies needed to comply with the MACT standard, which was renamed MATS (Mercury Air Toxics Standard) when the final rule was issued on December 16, 2011. We do not believe that any additional accruals are needed related to the Hutchings Station.

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 zero fair market value. Since DP&L did not apply push down accounting, this valuation did not affect the book value of these stations' valuation at DP&L. In the third quarter of 2012, DP&L performed an impairment review of its stations, and recorded an impairment of $80.8 million related to two of the stations, Conesville and Hutchings. See Note 15 for more information on this impairment.

6. Debt Obligations

Long-term debt is as follows:

Long-term debt $ in millions	**December 31, 2012**	December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	$ -	$ 470.0
Pollution control series maturing in January 2028 - 4.7%	**35.3**	35.3
Pollution control series maturing in January 2034 - 4.8%	**179.1**	179.1
Pollution control series maturing in September 2036 - 4.8%	**100.0**	100.0
Pollution control series maturing in November 2040 - variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)	-	100.0
U.S. Government note maturing in February 2061 - 4.2%	**18.3**	18.5
Capital lease obligations	**0.1**	0.4
Unamortized debt discount	**(0.1)**	(0.3)
Total long-term debt	**$ 332.7**	$ 903.0

Current portion - long-term debt $ in millions	**December 31, 2012**	December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	**$ 470.0**	$ -
Pollution control series maturing in November 2040 - variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)	**100.0**	-
U.S. Government note maturing in February 2061 - 4.2%	**0.1**	0.1
Capital lease obligations	**0.3**	0.3
Total current portion - long-term debt	**$ 570.4**	$ 0.4

(a) - range of interest rates for the twelve months ended December 31, 2012 and December 31, 2011, respectively.

At December 31, 2012, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions		
Due within one year	$	570.4
Due within two years		0.2
Due within three years		0.1
Due within four years		0.1
Due within five years		0.1
Thereafter		332.3
		903.2
Unamortized discount		(0.1)
Total long-term debt	$	903.1

On November 21, 2006, DP&L entered into a $220.0 million unsecured revolving credit agreement. This agreement was terminated by DP&L on August 29, 2011.

On December 4, 2008, the OAQDA issued $100.0 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, DP&L borrowed these funds from the OAQDA and issued corresponding First Mortgage Bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby letter of credit issued by JPMorgan Chase Bank, N.A. This letter of credit facility, which expires in December 2013, is irrevocable and has no subjective acceleration clauses. Since this letter of credit facility expires in December 2013, at which point the bondholders could tender the bonds, we have reflected these outstanding bonds as a current liability. Management will continue to monitor and evaluate market conditions over the next several months and make a determination to either seek a renewal of this standby letter of credit or to explore alternative financing arrangements. Fees associated with this letter of credit facility were not material during the years ended December 31, 2012 and 2011.

On April 20, 2010, DP&L entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides DP&L with the ability to increase the size of the facility by an additional $50.0 million. DP&L had no outstanding borrowings under this credit facility at December 31, 2012 or 2011. Fees associated with this revolving credit facility were not material during the twelve months ended December 31, 2012 or the period between April 20, 2010 and December 31, 2011. This facility also contains a $50.0 million letter of credit sublimit. As of December 31, 2012 and 2011, DP&L had no outstanding letters of credit against the facility.

On March 1, 2011, DP&L completed the purchase of $18.7 million electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base (WPAFB). DP&L financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum.

On August 24, 2011, DP&L entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a four year term expiring on August 24, 2015 and provides DP&L with the ability to increase the size of the facility by an additional $50.0 million. DP&L had no outstanding borrowings under this credit facility at December 31, 2012 or 2011. Fees associated with this revolving credit facility were not material during the year ended December 31, 2012 or the five months ended December 31, 2011. This facility also contains a $50.0 million letter of credit sublimit. As of December 31, 2012 and 2011, DP&L had no outstanding letters of credit against the facility.

Substantially all property, plant and equipment of DP&L is subject to the lien of the mortgage securing DP&L's First and Refunding Mortgage, dated October 1, 1935, with the Bank of New York Mellon as Trustee.

7. Income Taxes

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

$ in millions		**Year ended December 31, 2012**		Year ended December 31, 2011		Year ended December 31, 2010
Computation of tax expense						
Federal income tax expense / (benefit)[(a)]	$	**50.9**	$	103.8	$	144.2
Increases (decreases) in tax resulting from:						
State income taxes, net of federal effect		**(2.0)**		1.4		1.9
Depreciation of AFUDC - Equity		**3.0**		(3.2)		(2.2)
Investment tax credit amortized		**(2.5)**		(2.5)		(2.8)
Section 199 - domestic production deduction		**(2.5)**		(4.9)		(9.1)
Non-deductible merger-related compensation		**0.6**		3.6		-
ESOP		**-**		13.6		-
Compensation and benefits		**-**		(5.3)		-
Other, net [(b)]		**7.6**		(2.3)		3.2
Total tax expense	$	**55.1**	$	104.2	$	135.2
Components of Tax Expense						
Federal - current	$	**52.1**	$	54.9	$	83.1
State and Local - current		**1.0**		0.9		0.8
Total current		**53.1**		55.8		83.9
Federal - deferred		**4.7**		47.1		50.1
State and local - deferred		**(2.7)**		1.3		1.2
Total deferred		**2.0**		48.4		51.3
Total tax expense	$	**55.1**	$	104.2	$	135.2

$ in millions		**December 31, 2012**		December 31, 2011
Net non-current Assets / Liabilities				
Depreciation / property basis	$	**(622.1)**	$	(613.1)
Income taxes recoverable		**(12.3)**		(8.6)
Regulatory assets		**(20.6)**		(18.8)
Investment tax credit		**9.6**		10.5
Compensation and employee benefits		**0.3**		(4.2)
Other		**(6.9)**		(3.5)
Net non-current liabilities	$	**(652.0)**	$	(637.7)
Net current Assets / (Liabilities) [(c)]				
Other	$	**2.0**	$	1.5
Net current assets	$	**2.0**	$	1.5

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes expense of $7.6 million and benefits of $2.4 million and $0.3 million in 2012, 2011 and 2010, respectively, of income tax related to adjustments from prior years.
(c) Amounts are included within Other prepayments and current assets on the Balance Sheets of DP&L.

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

$ in million		**Year ended December 31, 2012**		Year ended December 31, 2011		Year ended December 31, 2010
Tax expense / (benefit)	**$**	**(0.8)**	$	(7.2)	$	0.1

Accounting for Uncertainty in Income Taxes
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		
Year ended December 31, 2011		
Balance at January 1, 2011	$	19.4
Tax positions taken during prior periods		2.0
Tax positions taken during current period		3.6
Balance at December 31, 2011	$	25.0
Year ended December 31, 2012		
Tax positions taken during prior periods		(6.3)
Tax positions taken during current period		(0.4)
Balance at December 31, 2012	$	18.3

Of the December 31, 2012 balance of unrecognized tax benefits, $19.4 million is due to uncertainty in the timing of deductibility offset by $1.1 million of unrecognized tax liabilities that would affect the effective tax rate.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The following table represents the amounts accrued as well as the expense / (benefit) recorded as of and for the periods noted below:

Amounts in Balance Sheet

$ in million		**Year ended December 31, 2012**		Year ended December 31, 2011		Year ended December 31, 2010
Liability	**$**	**0.8**	$	0.9	$	0.3

Amounts in Statement of Operations

$ in million		**Year ended December 31, 2012**		Year ended December 31, 2011		Year ended December 31, 2010
Expense / (benefit)	**$**	**(0.1)**	$	0.6	$	0.4

Following is a summary of the tax years open to examination by major tax jurisdiction:
U.S. Federal – 2007 and forward
State and Local – 2007 and forward

All of the unrecognized tax benefits are expected to settle within the next twelve months.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The examination was completed on January 18, 2013 and we do not expect the results of this examination to have a material effect on our financial condition, results of operations and cash flows.

As a result of the Merger, DPL and its subsidiaries file U.S. federal income tax returns as a part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, DPL and its subsidiaries filed a consolidated U.S. federal income tax return. 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.

8. Pension and Postretirement Benefits

DP&L sponsors a traditional defined benefit pension plan for substantially all employees of DPL. 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.

All DP&L management employees beginning employment on or after January 1, 2011 are enrolled in a cash balance pension plan. Similar to the traditional defined benefit 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.

In addition, we have a Supplemental Executive Retirement Plan (SERP) for certain retired key executives. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) effective January 1, 2006, which is for certain active and former key executives. Pursuant to the SEDCRP, we provide a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designate as hypothetical investment funds under the SEDCRP one or more of the investment funds provided under The Dayton Power and Light Company Employee Savings Plan. Each participant may change his or her hypothetical investment fund selection at specified times. If a participant does not elect a hypothetical investment fund(s), then we select the hypothetical investment fund(s) for such participant. Per the SEDCRP plan document, the balances in the SEDCRP, including earnings on contributions, were paid out to participants in December 2011, following the merger with AES on November 28, 2011. However, the SEDCRP continued and a 2011 contribution was calculated in March 2012. The SEDCRP was terminated by the Board of Directors as of December 31, 2012, but a 2012 contribution will be calculated and the balances, including earnings on contributions, will be paid to participants in 2013. We also have an unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. The unfunded liabilities for these agreements and the SEDCRP were $1.1 million and $0.8 million at December 31, 2012 and 2011, respectively.

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. DP&L made discretionary contributions of $40.0 million and $40.0 million to the defined benefit plan during the year ended December 31, 2011 and the year ended December 31, 2010, respectively.

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 at age 65. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

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.

The following tables set forth our pension and postretirement benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2012 and 2011. The amounts presented in the following tables for pension 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 postretirement include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
	2012	2011
Change in benefit obligation		
Benefit obligation at beginning of period	$ **365.2**	$ 333.8
Service cost	**6.2**	5.0
Interest cost	**17.3**	17.0
Plan amendments	**-**	7.2
Actuarial loss	**29.1**	21.6
Benefits paid	**(22.2)**	(19.4)
Benefit obligation at end of period	**395.6**	365.2
Change in plan assets		
Fair value of plan assets at beginning of period	**335.9**	291.8
Actual return on plan assets	**46.2**	23.1
Contributions to plan assets	**1.5**	40.4
Benefits paid	**(22.2)**	(19.4)
Fair value of plan assets at end of period	**361.4**	335.9
Funded status of plan	$ **(34.2)**	$ (29.3)

$ in millions	Postretirement	
	Years ended December 31,	
	2012	2011
Change in benefit obligation		
Benefit obligation at beginning of period	$ **21.7**	$ 23.7
Service cost	**0.1**	0.1
Interest cost	**0.9**	1.0
Actuarial (gain) / loss	**1.2**	(1.3)
Benefits paid	**(1.7)**	(2.0)
Medicare Part D reimbursement	**0.2**	0.2
Benefit obligation at end of period	**22.4**	21.7
Change in plan assets		
Fair value of plan assets at beginning of period	**4.5**	4.8
Actual return on plan assets	**0.2**	0.2
Contributions to plan assets	**1.2**	1.5
Benefits paid	**(1.7)**	(2.0)
Fair value of plan assets at end of period	**4.2**	4.5
Funded status of plan	$ **(18.2)**	$ (17.2)

$ in millions	Pension December 31, 2012	Pension December 31, 2011	Postretirement December 31, 2012	Postretirement December 31, 2011
Amounts recognized in the Balance sheets at December 31				
Current liabilities	$ **(0.4)**	$ (1.3)	$ **(0.6)**	$ (0.6)
Non-current liabilities	**(33.8)**	(27.9)	**(17.6)**	(16.6)
Net liability at December 31	$ **(34.2)**	$ (29.2)	$ **(18.2)**	$ (17.2)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost	$ **19.0**	$ 21.9	$ **0.8**	$ 0.9
Net actuarial loss / (gain)	**136.1**	140.2	**(5.7)**	(7.7)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	$ **155.1**	$ 162.1	$ **(4.9)**	$ (6.8)
Recorded as:				
Regulatory asset	$ **88.0**	$ 91.1	$ **0.5**	$ 1.0
Regulatory liability	**-**	-	**(5.0)**	(6.6)
Accumulated other comprehensive income	**67.1**	71.0	**(0.4)**	(1.2)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	$ **155.1**	$ 162.1	$ **(4.9)**	$ (6.8)

The accumulated benefit obligation for our defined benefit pension plans was $382.5 million and $355.5 million at December 31, 2012 and 2011, respectively.

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

Net Periodic Benefit Cost - Pension

$ in millions	Years ended December 31, 2012	2011	2010
Service cost	$ **6.2**	$ 5.0	$ 4.8
Interest cost	**17.3**	17.0	17.7
Expected return on assets (a)	**(22.7)**	(24.5)	(22.4)
Amortization of unrecognized:			
Actuarial loss	**8.8**	8.0	7.2
Prior service cost	**2.8**	2.1	3.7
Net periodic benefit cost before adjustments	**12.4**	7.6	11.0
Settlement Expense	**0.6**	-	-
Net periodic benefit cost after adjustments	$ **13.0**	$ 7.6	$ 11.0

(a) For purposes of calculating the expected return on pension plan assets under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be amortized into the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets was approximately $346.0 million in 2012, $335.0 million in 2011, and $274.0 million in 2010.

Net Periodic Benefit Income - Postretirement

$ in millions	Years ended December 31, 2012	2011	2010
Service cost	$ **0.1**	$ 0.1	$ 0.1
Interest cost	**0.9**	1.0	1.2
Expected return on assets (a)	**(0.3)**	(0.3)	(0.3)
Amortization of unrecognized:			
Actuarial gain	**(0.9)**	(1.1)	(1.1)
Prior service cost	**0.1**	0.1	0.1
Net periodic benefit income before adjustments	$ **(0.1)**	$ (0.2)	$ -

Pension

$ in millions	Years ended December 31, 2012	2011	2010
Net actuarial loss	$ **5.2**	$ 22.8	$ 1.9
Prior service cost	**-**	7.1	-
Reversal of amortization item:			
Net actuarial gain	**(9.4)**	(8.0)	(7.2)
Prior service credit	**(2.8)**	(2.0)	(3.7)
Transition asset	**-**	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(7.0)**	$ 19.9	$ (9.0)
Total recognized in net periodic benefit cost Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **6.0**	$ 27.5	$ 2.0

Postretirement

$ in millions	Years ended December 31, 2012	2011	2010
Net actuarial loss / (gain)	$ **1.1**	$ (1.3)	$ (1.9)
Prior service credit	**-**	-	-
Reversal of amortization item:			
Net actuarial loss	**0.9**	1.2	1.1
Prior service credit	**(0.1)**	(0.1)	(0.1)
Transition asset	**-**	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **1.9**	$ (0.2)	$ (0.9)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **1.8**	$ (0.4)	$ (0.9)

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2013 are:

$ in millions		Pension		Postretirement
Net actuarial loss / (gain)	$	9.3	$	(0.7)
Prior service cost	$	2.8	$	0.1

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.

For 2013, we are maintaining our expected long-term rate of return on assets assumption of 7.00% for pension plan assets and 6.00% for postretirement benefit plan assets. These expected returns are based primarily on portfolio investment allocation. There can be no assurance of our ability to generate these rates of return in the future.

Our overall discount rate was evaluated in relation to the Aon AA Above Median Yield Curve which represents a portfolio of Above Median AA-rated bonds used to settle pension obligations. Peer data and historical returns were also reviewed to verify the reasonableness and appropriateness of our discount rate used in the calculation of benefit obligations and expense.

The weighted average assumptions used to determine benefit obligations during the years ended December 31, 2012, 2011 and 2010 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2012	2011	2010	**2012**	2011	2010
Discount rate for obligations	**4.04%**	4.88%	5.31%	**3.75%**	4.62%	4.96%
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, 2012, 2011 and 2010 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2012	2011	2010	**2012**	2011	2010
Discount rate	**4.88%**	5.31%	5.75%	**4.62%**	4.96%	5.35%
Expected rate of return on plan assets	**7.00%**	8.00%	8.50%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	3.94%	4.44%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2012, 2011 and 2010 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2012	2011	2010	**2012**	2011	2010
Pre - age 65						
Current health care cost trend rate	**8.50%**	8.50%	9.50%	**8.00%**	8.50%	8.50%
Year trend reaches ultimate	**2019**	2018	2015	**2019**	2019	2018
Post - age 65						
Current health care cost trend rate	**8.00%**	8.00%	9.00%	**7.50%**	8.00%	8.00%
Year trend reaches ultimate	**2018**	2017	2014	**2018**	2018	2017
Ultimate health care cost trend rate	**5.00%**	5.00%	5.00%	**5.00%**	5.00%	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 postretirement benefit cost and the accumulated postretirement 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	$ (0.1)
Benefit obligation	$ 1.2	$ (1.0)

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

Estimated future benefit payments and Medicare Part D reimbursements

$ in millions	Pension	Postretirement
2013	$ 22.1	$ 2.5
2014	$ 22.5	$ 2.4
2015	$ 23.0	$ 2.3
2016	$ 23.3	$ 2.1
2017	$ 23.7	$ 1.9
2018-2022	$ 122.6	$ 7.6

We expect to make contributions of $0.4 million to our SERP in 2013 to cover benefit payments. We also expect to contribute $2.1 million to our other postretirement benefit plans in 2013 to cover benefit payments.

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 2012 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 116.56% and is estimated to be 116.56% until the 2013 status is certified in September 2013 for the 2013 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.

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.

Long-term strategic asset allocation guidelines are determined by management and take into account the Plan's long-term objectives as well as its short-term constraints. The target allocations for plan assets are 30 - 80% for equity securities, 30 - 65% for fixed income securities, 0 - 10% for cash and 0 - 25% for alternative investments. 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. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of our pension plan assets at December 31, 2012 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2012

Asset Category $ in millions	**Market Value at December 31, 2012**	**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	$ 14.3	$ -	$ 14.3	$ -
Large cap equity	50.5	-	50.5	-
International equity	37.0	-	37.0	-
Total equity securities	101.8	-	101.8	-
Debt Securities (b)				
Emerging markets debt	7.4	-	7.4	-
High yield bond	12.7	-	12.7	-
Long duration fund	188.6	-	188.6	-
Total debt securities	208.7	-	208.7	-
Cash and cash equivalents (c)				
Cash	13.9	13.9	-	-
Other investments (d)				
Limited partnership interest	-	-	-	-
Common collective fund	37.0	-	-	37.0
Total other investments	37.0	-	-	37.0
Total pension plan assets	$ 361.4	$ 13.9	$ 310.5	$ 37.0

(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 funds.
(b) This category includes investments in investment-grade fixed-income instruments that are designed to mirror the term of the pension assets and generally have a tenor between 10 and 30 years. 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 and the proceeds received from the sale of the **DPL** common stock, which was cashed out at $30/share. The fair value of cash equals its book value.
(d) This category represents a private equity fund that specializes in management buyouts 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 private equity fund is determined by the General Partner of the fund based on the performance of the individual companies. 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.

The fair values of our pension plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	**Market Value at December 31, 2011**	**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	$ 16.2	$ -	$ 16.2	$ -
Large cap equity	54.5	-	54.5	-
International equity	34.2	-	34.2	-
Total equity securities	104.9	-	104.9	-
Debt Securities (b)				
Long duration fund	130.8	-	130.8	-
Total debt securities	130.8	-	130.8	-
Cash and cash equivalents (c)				
Cash	28.0	28.0	-	-
Other investments (d)				
Limited partnership interest	0.8	-	-	0.8
Common collective fund	71.4	-	-	71.4
Total other investments	72.2	-	-	72.2
Total pension plan assets	$ 335.9	$ 28.0	$ 235.7	$ 72.2

(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 except for the **DPL** common stock which is valued using the closing price on the New York Stock Exchange.
(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 private equity fund that specializes in management buyouts 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 private equity fund is determined by the General Partner of the fund based on the performance of the individual companies. 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.

The change in the fair value for the pension assets valued using significant unobservable inputs (Level 3) was due to the following:

Change in fair value measurements of pension assets using significant unobservable inputs (Level 3)

$ in millions	Limited Partnership Interest	Common Collective Fund
Year ended December 31, 2011		
Beginning balance January 1, 2011	$ 2.8	$ 57.4
Actual return on plan assets:		
Relating to assets still held at the reporting date	(0.8)	(1.4)
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(1.2)	15.4
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2011	$ 0.8	$ 71.4
Year ended December 31, 2012		
Actual return on plan assets:		
Relating to assets still held at the reporting date	**-**	**1.4**
Relating to assets sold during the period	**0.9**	**-**
Purchases, sales, and settlements	**(1.7)**	**(35.8)**
Transfers in and / or out of Level 3	**-**	**-**
Ending balance at December 31, 2012	$ **(0.0)**	$ **37.0**

The fair values of our other postretirement benefit plan assets at December 31, 2012 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2012

Asset Category $ in millions	Market Value at December 31, 2012	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
JP Morgan Core Bond Fund (a)	$ 4.2	$ -	$ 4.2	$ -

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

The fair values of our other postretirement benefit plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	Market Value at December 31, 2011	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
JP Morgan Core Bond Fund (a)	$ 4.5	$ -	$ 4.5	$ -

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

During October 1992, our Board of Directors approved the formation of a Company-sponsored ESOP to fund matching contributions to DP&L's 401(k) retirement savings plan and certain other payments to eligible full-time employees. ESOP shares that were used to fund matching contributions to DP&L's 401(k) vested after either two or three years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately. In 1992, the ESOP Plan entered into a $90 million loan agreement with DPL in order to purchase shares of DPL common stock in the open market. The leveraged ESOP was funded by an exempt loan, which was secured by the ESOP shares. As debt service payments were made on the loan, shares were released on a pro rata basis. The term loan agreement provided for principal and interest on the loan to be paid prior to October 9, 2007, with the right to extend the loan for an additional ten years. In 2007, the maturity date was extended to October 7, 2017. Effective January 1, 2009, the interest on the loan was amended to a fixed rate of 2.06%, payable annually. Dividends received by the ESOP were used to repay the principal and interest on the ESOP loan to DPL. Dividends on the allocated shares were charged to retained earnings and the share value of these dividends was allocated to participants.

During December 2011, the ESOP Plan was terminated and participant balances were transferred to one of the two DP&L sponsored defined contribution 401(k) plans. On December 5, 2011, the ESOP Trust paid the total outstanding principal and interest of $68 million on the loan with DPL, using the merger proceeds from DPL common stock held within the ESOP suspense account.

Compensation expense recorded, based on the fair value of the shares committed to be released, amounted to $4.8 million and $6.7 million in the years ended 2011 and 2010, respectively.

9. Fair Value Measurements

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, 2012 and 2011. See also Note 10 for the fair values of our derivative instruments.

$ in millions	**December 31, 2012**		December 31, 2011	
	Cost	**Fair Value**	Cost	Fair Value
Assets				
Money market funds	**$ 0.2**	**$ 0.2**	$ 0.2	$ 0.2
Equity securities	**4.0**	**5.1**	3.9	4.4
Debt securities	**4.6**	**5.0**	5.0	5.5
Multi-strategy fund	**0.3**	**0.3**	0.3	0.2
Total assets	**$ 9.1**	**$ 10.6**	$ 9.4	$ 10.3
Liabilities				
Debt	**$ 903.1**	**$ 926.9**	$ 903.4	$ 934.5

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 amortized cost in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2013 to 2061.

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 and these assets are not used for general operating purposes. 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 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 $1.6 million ($1.0 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2012 and $1.0 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2011.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. $0.1 million ($0.1 million after tax) of unrealized gains were reversed into earnings during the past twelve months. $0.1 million ($0.1 million after tax) of unrealized gains are expected to be reversed to earnings over the next twelve months.

Net Asset Value (NAV) per Unit

The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of December 31, 2012 and 2011. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2012, DP&L did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2012	Fair Value at December 31, 2011	Unfunded Commitments	Redemption Frequency
Money market fund (a)	$ **0.2**	$ 0.2	$ -	Immediate
Equity securities (b)	**5.1**	4.4	-	Immediate
Debt Securities (c)	**5.0**	5.5	-	Immediate
Multi-strategy fund (d)	**0.3**	0.2	-	Immediate
Total	$ **10.6**	$ 10.3	$ -	

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current net asset value per unit.
(b) This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.
(c) This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.
(d) This category includes a mix of actively managed funds holding investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.

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); or 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, 2012 and 2011.

The fair value of assets and liabilities at December 31, 2012 and 2011 measured on a recurring basis and the respective category within the fair value hierarchy for DP&L was determined as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value at December 31, 2012(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	5.1	-	5.1	-
Debt securities	5.0	-	5.0	-
Multi-strategy fund	0.3	-	0.3	-
Total Master trust assets	10.6	0.2	10.4	-
Derivative assets				
Heating oil futures	0.2	0.2	-	-
Forward power contracts	7.3	-	7.3	-
Total derivative assets	7.5	0.2	7.3	-
Total assets	$ 18.1	$ 0.4	$ 17.7	$ -
Liabilities				
Derivative liabilities				
FTRs	$ (0.1)	$ -	$ -	$ (0.1)
Forward power contracts	(11.6)	-	(11.6)	-
Total derivative liabilities	(11.7)	-	(11.6)	(0.1)
Long Term debt	(926.9)	-	(908.0)	(18.9)
Total liabilities	$ (938.6)	$ -	$ (919.6)	$ (19.0)

(a) Includes credit valuation adjustment.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value at December 31, 2011(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	4.4	-	4.4	-
Debt securities	5.5	-	5.5	-
Multi-strategy fund	0.2	-	0.2	-
Total Master trust assets	10.3	-	10.3	-
Derivative assets				
FTRs	0.1	-	0.1	-
Heating oil futures	1.8	1.8	-	-
Forward power contracts	4.1	-	4.1	-
Total derivative assets	6.0	1.8	4.2	-
Total assets	$ 16.3	$ 1.8	$ 14.5	$ -
Liabilities				
Derivative liabilities				
Forward NYMEX coal contracts	$ (14.5)	$ -	$ (14.5)	$ -
Forward power contracts	(5.0)	-	(5.0)	-
Total derivative liabilities	(19.5)	-	(19.5)	-
Total liabilities	$ (19.5)	$ -	$ (19.5)	$ -

(a) Includes credit valuation adjustment.

We use the market approach to value our financial instruments. 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 and forward NYMEX-quality coal 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; and interest rate hedges, which use observable inputs to populate a pricing model. Financial transmission rights are considered a Level 3 input, beginning April 1, 2012, 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. Our long-term leases and the WPAFB note are 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 98% of the inputs to the fair value of our derivative instruments are from quoted market prices for DP&L.

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. A new ARO liability in the amount of $0.1 million was established in 2012 associated with a gypsum landfill disposal site that is presently under construction. This increase in 2012 was offset by a $0.1 million reduction in ARO for asbestos as a result of an acceleration of removal and remediation activities. During the year ended December 31, 2011, there were gross additions of $1.0 million to our existing river structures, asbestos, ash landfill and underground storage tank AROS.

10. 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 or marked to market each reporting period.

At December 31, 2012, DP&L had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	6.9	-	6.9
Heating Oil Futures	Mark to Market	Gallons	1,764.0	-	1,764.0
Forward Power Contracts	Cash Flow Hedge	MWh	1,021.0	(2,197.9)	(1,176.9)
Forward Power Contracts	Mark to Market	MWh	2,296.6	(4,760.4)	(2,463.8)

At December 31, 2011, DP&L had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	(0.7)	6.4
Heating Oil Futures	Mark to Market	Gallons	2,772.0	-	2,772.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(341.6)	544.6
Forward Power Contracts	Mark to Market	MWh	525.1	(525.1)	-
NYMEX-quality Coal Contracts *(a)*	Mark to Market	Tons	2,015.0	-	2,015.0

(a) Includes our partners' share for the jointly-owned stations that DP&L operates.

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 table provides information for DP&L concerning gains or losses recognized in AOCI for the cash flow hedges:

	Year ended December 31, 2012		Year ended December 31, 2011		Year ended December 31, 2010	
$ in millions	**Power**	**Interest Rate**	Power	Interest Rate	Power	Interest Rate
Beginning accumulated derivative gain / (loss) in AOCI	$ **(0.8)**	$ **9.8**	$ (1.8)	$ 12.2	$ (1.4)	$ 14.7
Net gains / (losses) associated with current period hedging transactions	**(3.0)**	**-**	(1.2)	-	3.1	-
Net gains reclassified to earnings:						
Interest Expense	**-**	**(2.5)**	-	(2.4)	-	(2.5)
Revenues	**(1.1)**	**-**	1.2	-	(3.5)	-
Purchased Power	**0.2**	**-**	1.0	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	$ **(4.7)**	$ **7.3**	$ (0.8)	$ 9.8	$ (1.8)	$ 12.2

Net gains or losses associated with the ineffective portion of the hedging transactions were immaterial in the years ended December 31, 2012, 2011 and 2010.

Portion expected to be reclassified to earnings in the next twelve months *(a)*	$ **(6.2)**	$ **(2.5)**
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**24**	**-**

(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.

The following table shows the fair value and balance sheet classification of DP&L's derivative instruments designated as hedging instruments at December 31, 2012 and 2011.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2012

$ in millions	Fair Value (a)	Balance Sheet Location
Short-term Derivative Positions		
Forward Power Contracts in an Asset Position	$ 0.5	Other prepayments and current assets
Forward Power Contracts in a Liability Position	(6.7)	Other current liabilities
Total Short-term Cash Flow Hedges	(6.2)	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	0.5	Other deferred assets
Forward Power Contracts in a Liability Position	(1.5)	Other deferred credits
Total Long-term Cash Flow Hedges	(1.0)	
Total Cash Flow Hedges	$ (7.2)	

(a) Includes credit valuation adjustment.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value (a)	Balance Sheet Location
Short-term Derivative Positions		
Forward Power Contracts in an Asset Position	$ 1.5	Other prepayments and current assets
Forward Power Contracts in a Liability Position	(0.2)	Other current liabilities
Total Short-term Cash Flow Hedges	1.3	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	0.1	Other deferred assets
Forward Power Contracts in a Liability Position	(2.6)	Other deferred credits
Total Long-term Cash Flow Hedges	(2.5)	
Total Cash Flow Hedges	$ (1.2)	

(a) Includes credit valuation adjustment.

Mark to Market Accounting

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 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, forward NYMEX-quality coal contracts 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 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 and the NYMEX-quality coal contracts 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, 2012 and 2011.

	Year ended December 31, 2012				
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ 14.5	$ (1.6)	$ (0.2)	$ 3.0	$ 15.7
Realized gain / (loss)	(29.5)	1.9	0.5	4.9	(22.2)
Total	$ (15.0)	$ 0.3	$ 0.3	$ 7.9	$ (6.5)
Recorded on Balance Sheet:					
Partners' share of gain	$ 4.2	$ -	$ -	$ -	$ 4.2
Regulatory (asset) / liability	1.0	(0.6)	-	-	0.4
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	2.7	2.7
Purchased Power	-	-	0.3	5.2	5.5
Fuel	(20.2)	0.7	-	-	(19.5)
O&M	-	0.2	-	-	0.2
Total	$ (15.0)	$ 0.3	$ 0.3	$ 7.9	$ (6.5)

Year ended December 31, 2011

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ (52.1)	$ 0.1	$ (0.1)	$ 0.3	$ (51.8)
Realized gain / (loss)	7.5	2.3	(0.6)	(1.4)	7.8
Total	$ (44.6)	$ 2.4	$ (0.7)	$ (1.1)	$ (44.0)
Recorded on Balance Sheet:					
Partners' share of loss	$ (26.1)	$ -	$ -	$ -	$ (26.1)
Regulatory asset	(7.1)	-	-	-	(7.1)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	2.5	2.5
Purchased Power	-	-	(0.7)	(3.6)	(4.3)
Fuel	(11.4)	2.2	-	-	(9.2)
O&M	-	0.2	-	-	0.2
Total	$ (44.6)	$ 2.4	$ (0.7)	$ (1.1)	$ (44.0)

Year ended December 31, 2010

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ 33.5	$ 2.8	$ (0.6)	$ 0.1	$ 35.8
Realized gain / (loss)	3.2	(1.6)	(1.5)	(0.1)	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8
Recorded on Balance Sheet:					
Partners' share of gain	$ 20.1	$ -	$ -	$ -	$ 20.1
Regulatory liability	4.6	1.1	-	-	5.7
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	-	-
Purchased Power	-	-	(2.1)	-	(2.1)
Fuel	12.0	0.1	-	-	12.1
O&M	-	-	-	-	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8

The following tables show the fair value and balance sheet classification of DP&L's derivative instruments not designated as hedging instruments at December 31, 2012 and 2011.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
December 31, 2012

$ in millions		Fair Value (a)	Balance Sheet Location
Short-term Derivative Positions			
FTRs in a Liability Position	$	(0.1)	Other current liabilities
Forward Power Contracts in an Asset Position		2.8	Other prepayments and current assets
Forward Power Contracts in a Liability Position		(2.7)	Other current liabilities
Heating Oil Futures in an Asset Position		0.2	Other prepayments and current assets
Total Short-term Derivative MTM Positions		0.2	
Long-term Derivative Positions			
Forward Power Contracts in an Asset Position		3.6	Other deferred assets
Forward Power Contracts in a Liability Position		(0.7)	Other deferred credits
Total Long-term Derivative MTM Positions		2.9	
Net MTM Position	$	3.1	

(a) Includes credit valuation adjustment.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
December 31, 2011

$ in millions		Fair Value (a)	Balance Sheet Location
Short-term Derivative Positions			
FTRs in an Asset Position	$	0.1	Other prepayments and current assets
Forward Power Contracts in an Asset Position		1.0	Other prepayments and current assets
Forward Power Contracts in a Liability Position		(0.9)	Other current liabilities
NYMEX-quality Coal Forwards in a Liability Position		(8.3)	Other current liabilities
Heating Oil Futures in an Asset Position		1.8	Other prepayments and current assets
Total Short-term Derivative MTM Positions		(6.3)	
Long-term Derivative Positions			
Forward Power Contracts in an Asset Position		1.5	Other deferred assets
Forward Power Contracts in a Liability Position		(1.3)	Other deferred credits
NYMEX-quality Coal Forwards in a Liability Position		(6.2)	Other deferred credits
Total Long-term Derivative MTM Positions		(6.0)	
Net MTM Position	$	(12.3)	

(a) Includes credit valuation adjustment.

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. If our debt were to fall below investment grade, we would be 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. The changes in our credit ratings in November 2012 have triggered the provisions discussed above with some of our counterparties. Since our debt has fallen below investment grade, 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, 2012 is $11.7 million. This amount is offset by $3.6 million in a broker margin account and with other counterparties 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 $6.4 million. If DP&L debt were to fall below investment grade, DP&L could be required to post collateral for the remaining $1.7 million.

11. Share-based Compensation

In April 2006, DPL's shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective for a term of ten years. The Compensation Committee of the Board of Directors designated the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. A total of 4,500,000 shares of DPL common stock had been reserved for issuance under the EPIP. The EPIP also covered certain employees of DP&L.

As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date. The remaining compensation expense of $5.5 million ($3.6 million after tax) was expensed as of the Merger date.

The following table summarizes share-based compensation expense (note that there is no share-based compensation activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Restricted stock units	$ -	$ -
Performance shares	2.4	2.1
Restricted shares	5.3	1.7
Non-employee directors' RSUs *(a)*	0.6	0.4
Management performance shares	1.8	0.5
Share-based compensation included in Operation and maintenance expense	10.1	4.7
Income tax benefit	(3.5)	(1.6)
Total share-based compensation, net of tax	$ 6.6	$ 3.1

(a) Includes an amount associated with compensation awarded to DPL's Board of Directors which is immaterial in total.

Share-based awards issued in DPL's common stock were distributed from treasury stock prior to the Merger; as of the Merger date, remaining share-based awards were distributed in cash in accordance with the Merger agreement.

Determining Fair Value

Valuation and Amortization Method – We estimated the fair value of performance shares using a Monte Carlo simulation; restricted shares were valued at the closing market price on the day of grant and the Directors' RSUs were valued at the closing market price on the day prior to the grant date. We amortized the fair value of all awards on a straight-line basis over the requisite service periods, which are generally the vesting periods.

Expected Volatility – Our expected volatility assumptions were based on the historical volatility of DPL common stock. The volatility range captured the high and low volatility values for each award granted based on its specific terms.

Expected Life – The expected life assumption represented the estimated period of time from the grant date until the exercise date and reflected historical employee exercise patterns.

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award was based on the corresponding yield curve in effect at the time of the valuation for U.S. Treasury bonds having the same term as the expected life of the award, i.e., a five-year bond rate was used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield was based on DPL's current dividend rate, adjusted as necessary to capture anticipated dividend changes and the 12 month average DPL common stock price.

Expected Forfeitures – The forfeiture rate used to calculate compensation expense was based on DPL's historical experience, adjusted as necessary to reflect special circumstances.

Stock Options

In 2000, DPL's Board of Directors adopted and DPL's shareholders approved The DPL Inc. Stock Option Plan. With the approval of the EPIP in April 2006, no new awards were granted under The DPL Inc. Stock Option Plan. Prior to the Merger, all outstanding stock options had been exercised or had expired.

Summarized stock option activity was as follows (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,			
$ in millions		2011		2010
Options:				
Outstanding at beginning of period		351,500		417,500
Granted		-		-
Exercised		(75,500)		(66,000)
Expired		(276,000)		-
Forfeited		-		-
Outstanding at end of period		-		351,500
Exercisable at end of period		-		351,500
Weighted average option prices per share:				
Outstanding at beginning of period	$	28.04	$	27.16
Granted	$	-	$	-
Exercised	$	21.02	$	21.00
Expired	$	29.42	$	-
Forfeited	$	-	$	-
Outstanding at end of period	$	-	$	28.04
Exercisable at end of period	$	-	$	28.04

The following table reflects information about stock option activity during the period (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,			
$ in millions		2011		2010
Weighted-average grant date fair value of options granted during the period	$	-	$	-
Intrinsic value of options exercised during the period	$	0.7	$	0.5
Proceeds from options exercised during the period	$	1.6	$	1.4
Excess tax benefit from proceeds of options exercised	$	0.2	$	0.1
Fair value of options that vested during the period	$	-	$	-
Unrecognized compensation expense	$	-	$	-
Weighted-average period to recognize compensation expense (in years)		-		-

Restricted Stock Units (RSUs)

RSUs were granted to certain key employees prior to 2001. As of the Merger date, there were no RSUs outstanding.

Summarized RSU activity was as follows (note that there is no RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
RSUs:		
Outstanding at beginning of period		
Granted	-	3,311
Dividends	-	-
Exercised	-	-
Forfeited	-	(3,311)
Outstanding at end of period	-	-
	-	-
Exercisable at end of period	-	-

Performance Shares

Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which DPL granted a targeted number of performance shares of common stock to executives. Grants under the LTIP were awarded based on a Total Shareholder Return Relative to Peers performance. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation.

At the Merger date, vesting for all non-vested LTIP performance shares was accelerated on a pro rata basis and such shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized performance share activity was as follows (note that there is no performance share activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Performance shares:		
Outstanding at beginning of period	278,334	237,704
Granted	85,093	161,534
Dividends	(198,699)	(91,253)
Exercised	(66,836)	-
Forfeited	(97,892)	(29,651)
Outstanding at end of period	-	278,334
Exercisable at end of period	-	66,836

The following table reflects information about performance share activity during the period (note that there is no performance share activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Weighted-average grant date fair value of performance shares granted during the period	$ 2.2	$ 2.9
Intrinsic value of performance shares exercised during the period	$ 6.0	$ 2.5
Proceeds from performance shares exercised during the period	$ -	$ -
Excess tax benefit from proceeds of performance shares exercised	$ 0.7	$ -
Fair value of performance shares that vested during the period	$ 4.7	$ 1.6
Unrecognized compensation expense	$ -	$ 2.4
Weighted-average period to recognize compensation expense (in years)	-	1.7

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the performance shares granted during the period:

	Years ended December 31,	
$ in millions	2011	2010
Expected volatility	24.0%	24.3%
Weighted-average expected volatility	24.0%	24.3%
Expected life (years)	3.0	3.0
Expected dividends	5.0%	4.5%
Weighted-average expected dividends	5.0%	4.5%
Risk-free interest rate	1.2%	1.4%

Restricted Shares

Under the EPIP, the Board of Directors granted shares of DPL Restricted Shares to various executives and other key employees. These Restricted Shares were registered in the recipient's name, carried full voting privileges, received dividends as declared and paid on all DPL common stock and vested after a specified service period.

In July 2008, the Board of Directors granted Restricted Share awards under the EPIP to a select group of management employees. The management Restricted Share awards had a three-year requisite service period, carried full voting privileges and received dividends as declared and paid on all DPL common stock.

On September 17, 2009, the Board of Directors approved a two-part equity compensation award under the EPIP for certain of DPL's executive officers. The first part was a Restricted Share grant and the second part was a matching Restricted Share grant. These Restricted Share grants generally vested after five years if the participant remained continuously employed with DPL or a DPL subsidiary and if the year-over-year average EPS had increased by at least 1% from 2009 to 2013. Under the matching Restricted Share grant, participants had a three-year period from the date of plan implementation during which they could purchase DPL common stock equal in value to up to two times their 2009 base salary. DPL matched the shares purchased with another grant of Restricted Shares (matching Restricted Share grant). The percentage match by DPL is detailed in the table below. The matching Restricted Share grant would have generally vested over a three-year period if the participant continued to hold the originally purchased shares and remained continuously employed with DPL or a DPL subsidiary. The Restricted Shares were registered in the recipient's name, carried full voting privileges and received dividends as declared and paid on all DPL common stock.

The matching criteria were:

Value (Cost Basis) of Shared Purchased as a % of 2009 Base Salary	Company % Match of Value of Shares Purchased
1% to 25%	25%
>25% to 50%	50%
>50% to 100%	75%
>100% to 200%	125%

The matching percentage was applied on a cumulative basis and the resulting Restricted Share grant was adjusted at the end of each calendar quarter. As a result of the Merger, the matching Restricted Share grants were suspended in March 2011.

In February 2011, the Board of Directors granted a targeted number of time-vested Restricted Shares to executives under the LTIP. These Restricted Shares did not carry voting privileges nor did they receive dividend rights during the vesting period. In addition, a one-year holding period was implemented after the three-year vesting period was completed.

Restricted Shares could only be awarded in DPL common stock.

At the Merger date, vesting for all non-vested Restricted Shares was accelerated and all outstanding shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized Restricted Share activity was as follows (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Restricted shares:		
Outstanding at beginning of period	219,391	218,197
Granted	67,346	42,977
Exercised	(286,737)	(20,803)
Forfeited	-	(20,980)
Outstanding at end of period	-	219,391
Exercisable at end of period	-	-

The following table reflects information about Restricted Share activity during the period (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Weighted-average grant date fair value of restricted shares granted during the period	$ 1.8	$ 1.1
Intrinsic value of restricted shares exercised during the period	$ 8.6	$ 0.4
Proceeds from restricted shares exercised during the period	$ -	$ -
Excess tax benefit from proceeds of restricted shares exercised	$ 0.5	$ 0.1
Fair value of restricted shares that vested during the period	$ 7.5	$ 0.6
Unrecognized compensation expense	$ -	$ 3.4
Weighted-average period to recognize compensation expense (in years)	-	2.7

Non-Employee Director RSUs

Under the EPIP, as part of their annual compensation for service to DPL and DP&L, each non-employee Director received a retainer in RSUs on the date of the shareholders' annual meeting. The RSUs became non-forfeitable on April 15 of the following year. The RSUs accrued quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs became exercisable and were distributed in DPL common stock, unless the Director chose to defer receipt of the shares until a later date. The RSUs were valued at the closing stock price on the day prior to the grant and the compensation expense was recognized evenly over the vesting period.

At the Merger date, vesting for the remaining non-vested RSUs was accelerated and all vested RSUs (current and prior years) were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

The following table reflects information about RSU activity (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Restricted stock units:		
Outstanding at beginning of period	16,320	20,712
Granted	14,392	15,752
Dividends accrued	3,307	2,484
Vested and exercised	(34,019)	(2,618)
Vested, exercised and deferred	-	(20,010)
Forfeited	-	-
Outstanding at end of period	-	16,320
Exercisable at end of period	-	-

The following table reflects information about non-employee Director RSU activity during the period (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	$ 0.5	$ 0.5
Intrinsic value of non-employee Director RSUs exercised during the period	$ 1.0	$ 0.5
Proceeds from non-employee Director RSUs exercised during the period	$ -	$ -
Excess tax benefit from proceeds of non-employee Director RSUs exercised	$ -	$ -
Fair value of non-employee Director RSUs that vested during the period	$ 1.0	$ 0.6
Unrecognized compensation expense	$ -	$ 0.1
Weighted-average period to recognize compensation expense (in years)	-	0.3

Management Performance Shares

Under the EPIP, the Board of Directors granted compensation awards for select management employees. The grants had a three year requisite service period and certain performance conditions during the performance period. The management performance shares could only be awarded in DPL common stock.

At the Merger date, vesting for all non-vested management performance shares was accelerated; some of the awards vested at target shares and other awards vested at a pro rata share of target. All vested shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized management performance share activity was as follows (note that there is no management performance share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Management performance shares:		
Outstanding at beginning of period	104,124	84,241
Granted	49,510	37,480
Expired	(31,081)	-
Exercised	(111,289)	-
Forfeited	(11,264)	(17,597)
Outstanding at end of period	-	104,124
Exercisable at end of period	-	31,081

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the management performance shares granted during the period:

	Years ended December 31,	
$ in millions	2011	2010
Expected volatility	24.0%	24.3%
Weighted-average expected volatility	24.0%	24.3%
Expected life (years)	3.0	3.0
Expected dividends	5.0%	4.5%
Weighted-average expected dividends	5.0%	4.5%
Risk-free interest rate	1.2%	1.4%

The following table reflects information about management performance share activity during the period (note that there is no management performance share activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Weighted-average grant date fair value of management performance shares granted during the period	$ 1.3	$ 0.9
Intrinsic value of management performance shares exercised during the period	$ 3.3	$ -
Proceeds from management performance shares exercised during the period	$ -	$ -
Excess tax benefit from proceeds of management performance shares exercised	$ -	$ -
Fair value of management performance shares that vested during the period	$ 2.7	$ 0.9
Unrecognized compensation expense	$ -	$ 0.9
Weighted-average period to recognize compensation expense (in years)	-	1.7

12. Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,058 were outstanding as of December 31, 2012. DP&L also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2012. The table below details the preferred shares outstanding at December 31, 2012 and 2011:

$ in millions except per share amounts	Preferred Stock Rate	December 31, 2012 and 2011: Redemption price ($ per share)	December 31, 2012 and 2011: Shares Outstanding	Par Value ($ in millions): December 31, 2012	Par Value ($ in millions): December 31, 2011
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	65,380	6.6	6.6
Total			228,058	$ 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. 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.

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, 2012, DP&L's retained earnings of $534.2 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.

13. Common Shareholders' Equity

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2012. 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.

14. Contractual Obligations, Commercial Commitments and Contingencies

DP&L – Equity Ownership Interest
DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of December 31, 2012, DP&L could be responsible for the repayment of 4.9%, or $78.2 million, of a $1,596.5 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2012, 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, 2012, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Long-term debt	$ 903.2	$ 570.4	$ 0.3	$ 0.2	$ 332.3
Interest payments	361.9	34.0	31.6	31.6	264.7
Pension and postretirement payments	256.2	24.6	50.3	51.1	130.2
Operating leases	1.0	0.4	0.6	-	-
Coal contracts (a)	586.4	227.6	150.6	138.8	69.4
Limestone contracts (a)	26.8	5.4	10.7	10.7	-
Purchase orders and other contractual obligations	55.9	34.6	10.9	10.4	-
Reserve for uncertain tax positions	18.3	18.3	-	-	-
Total contractual obligations	$ 2,209.7	$ 915.3	$ 255.0	$ 242.8	$ 796.6

(a) Total at DP&L operated units.

Long-term debt:
DP&L's long-term debt as of December 31, 2012, consists of first mortgage bonds and tax-exempt pollution control bonds. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 6 for additional information.

Interest payments:
Interest payments are associated with the long-term debt described above. The interest payments relating to variable-rate debt are projected using the interest rate prevailing at December 31, 2012.

Pension and postretirement payments:
As of December 31, 2012, DP&L had estimated future benefit payments as outlined in Note 8. These estimated future benefit payments are projected through 2022.

Capital leases:
As of December 31, 2012, DP&L had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:
As of December 31, 2012, DP&L had several immaterial operating leases with various terms and expiration dates.

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:
DP&L has entered into various limestone contracts to supply limestone used in the operation of FGD equipment at its generating facilities.

Purchase orders and other contractual obligations:
As of December 31, 2012, DP&L had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Reserve for uncertain tax positions:
As of December 31, 2012, DP&L had $18.3 million in uncertain tax positions which are expected to be resolved within the next year.

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, 2012, cannot be reasonably determined.

Environmental Matters
DP&L's facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. As well as 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 these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated. We have estimated liabilities of approximately $3.6 million for environmental matters. We evaluate the potential liability related to probable losses arising from 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 electric generating stations. Some of these matters could have material adverse impacts on the operation of the stations; especially the stations that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired generating units that do not have this equipment installed. DP&L owns 100% of the Hutchings Station and a 50% interest in Beckjord Unit 6.

On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our commonly owned Unit 6, in December 2014. This was followed by a notification by the joint owners of Beckjord 6 to PJM, dated April 12, 2012, of a planned June 1, 2015 deactivation of this unit. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision.

DP&L has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated June 1, 2013. In addition, DP&L has notified PJM that the remaining Hutchings units will be deactivated by June 1, 2015. We do not believe that any accruals are needed related to the Hutchings Station.

Environmental Matters Related to Air Quality

Clean Air Act Compliance
In 1990, the federal government amended the CAA to further regulate air pollution. Under the CAA, the USEPA sets limits on how much of a pollutant can be in the ambient air anywhere in the United States. The CAA allows individual states to have stronger pollution controls than those set under the CAA, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.

Cross-State Air Pollution Rule
The USEPA promulgated the "Clean Air Interstate Rule" (CAIR) on March 10, 2005, which required allowance surrender for SO2 and NOx emissions from existing electric generating stations located in 28 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NOx and SO2, respectively. A second phase with additional allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the USEPA.

In response to the D.C. Circuit's opinion, on July 7, 2011, the USEPA issued a final rule titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States," which is now referred to as the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO2 and NOx emissions from covered sources, such as power stations. Once fully implemented in 2014, the rule would have required additional SO2 emission reductions of 73% and additional NOx reductions of 54% from 2005 levels. Many states, utilities and other affected parties filed petitions for review, challenging the CSAPR before the U.S. Court of Appeals for the District of Columbia. A large subset of the Petitioners also sought a stay of the CSAPR. On December 30, 2011, the D.C. Circuit granted a stay of the CSAPR and directed the USEPA to continue administering CAIR. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that USEPA overstepped its regulatory authority by requiring states to make reductions beyond the levels required in the CAA and failed to provide states an initial opportunity to adopt their own measures for achieving federal compliance. As a result of this ruling, the surviving provisions of CAIR will continue to serve as the governing program until USEPA takes further action or the U.S. Congress intervenes. Assuming that USEPA constructs a replacement interstate transport rule addressing the D.C. Circuit Court's ruling, we believe companies will have three years or more before they would be required to comply with a replacement rule. At this time, it is not possible to predict the details of such a replacement transport rule or what impacts it may have on our consolidated financial condition, results of operations or cash flows. On October 5, 2012, USEPA, several states and cities, as well as environmental and health organizations, filed petitions with the D.C. Circuit Court requesting a rehearing by all of the judges of the D.C. Circuit Court of the case pursuant to which the three-judge panel ruled that CSAPR be vacated. On January 24, 2013, the D.C. Circuit Court denied this petition for rehearing en banc of the D.C. Circuit Court's August 2012 decision to vacate CSAPR. Therefore, CAIR remains in effect. If CSAPR were to be reinstated in its current form, we do not expect any material capital costs for DP&L's stations, assuming Beckjord 6 and Hutchings generating stations will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards. Because we cannot predict the final outcome of the replacement interstate transport rulemaking, we cannot predict its financial impact on DP&L's operations.

Mercury and Other Hazardous Air Pollutants
On May 3, 2011, the USEPA published proposed Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units. The standards include new requirements for emissions of mercury and a number of other heavy metals. The USEPA Administrator signed the final rule, now called MATS (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Our affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. DP&L is evaluating the costs that may be incurred to comply with the new requirement; however, MATS could have a material adverse effect on our results of operations and result in material compliance costs.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at DP&L's generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. In December 2011, the USEPA proposed additional changes to this rule and solicited comments. On December 21, 2012, the Administrator of USEPA signed the final rule, which will be followed by publication in the Federal Register. Compliance costs are not expected to be material to DP&L's operations.

On May 3, 2010, the National Emissions Standards for Hazardous Air Pollutants for compression ignition (CI) reciprocating internal combustion engines (RICE) became effective. The units affected at DP&L are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. DP&L expects to meet this deadline and expects the compliance costs to be immaterial.

National Ambient Air Quality Standards
On January 5, 2005, the USEPA published its final non-attainment designations for the National Ambient Air Quality Standard (NAAQS) for Fine Particulate Matter 2.5 (PM 2.5). These designations included counties and partial counties in which DP&L operates and/or owns generating facilities. On December 31, 2012, USEPA redesignated Adams County, where Stuart and Killen are located, to attainment. This status may be temporary, as on December 14, 2012, the USEPA tightened the PM 2.5 standard to 12.0 micrograms per cubic meter. This will begin a process of redesignations during 2014. We cannot predict the effect the revisions to the PM 2.5 standard will have on DP&L's financial condition or results of operations.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. DP&L cannot determine the effect of this potential change, if any, on its operations.

Effective April 12, 2010, the USEPA implemented revisions to its primary NAAQS for nitrogen dioxide. This change may affect certain emission sources in heavy traffic areas like the I-75 corridor between Cincinnati and Dayton after 2016. Several of our facilities or co-owned facilities are within this area. DP&L cannot determine the effect of this potential change, if any, on its operations.

Effective August 23, 2010, the USEPA implemented revisions to its primary NAAQS for SO_2 replacing the current 24-hour standard and annual standard with a one hour standard. DP&L cannot determine the effect of this potential change, if any, on its operations.

On May 5, 2004, the USEPA issued its proposed regional haze rule, which addresses how states should determine the Best Available Retrofit Technology (BART) for sources covered under the regional haze rule. Final rules were published July 6, 2005, providing states with several options for determining whether sources in the state should be subject to BART. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

Carbon Dioxide and Other Greenhouse Gas Emissions
In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under

the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders CO_2 and other GHGs "regulated air pollutants" under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring Rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to DP&L cannot be determined at this time, but the cost of compliance could be material.

On April 13, 2012, the USEPA published its proposed GHG standards for new electric generating units (EGUs) under CAA subsection 111(b), which would require certain new EGUs to meet a standard of 1,000 pounds of CO_2 per megawatt-hour, a standard based on the emissions limitations achievable through natural gas combined cycle generation. The proposal anticipates that affected coal-fired units would need to install carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. Furthermore, the USEPA may propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d). These latter rules may focus on energy efficiency improvements at electric generating stations. We cannot predict the effect of these standards, if any, on DP&L's operations.

Approximately 97% of the energy we produce is generated by coal. DP&L's share of CO_2 emissions at generating stations we own and co-own is approximately 16 million tons annually. Further GHG legislation or regulation finalized at a future date could have a significant effect on DP&L's operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation or regulation, we cannot predict the final outcome or the financial impact that such legislation or regulation may have on DP&L.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Units
On June 20, 2011, the U.S. Supreme Court ruled that the USEPA's regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation in the court system. Although we are not named as a party to these lawsuits, DP&L is a co-owner of coal-fired stations with Duke Energy and AEP (or their subsidiaries) that could have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including DP&L. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs' original suits that sought relief under state law.

As a result of a 2008 consent decree entered into with the Sierra Club and approved by the U.S. District Court for the Southern District of Ohio, DP&L and the other owners of the Stuart generating station are subject to certain specified emission targets related to NOx, SO_2 and particulate matter. The consent decree also includes commitments for energy efficiency and renewable energy activities. An amendment to the consent decree was entered into and approved in 2010 to clarify how emissions would be computed during malfunctions. Continued compliance with the consent decree, as amended, is not expected to have a material effect on DP&L's results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Units
In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and Ohio Power (Conesville Unit 4) and co-owned by DP&L were referenced in these actions. Although DP&L was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect DP&L's co-owned units.

In June 2000, the USEPA issued an NOV to the DP&L-operated Stuart generating station (co-owned by DP&L, Duke Energy, and Ohio Power) for alleged violations of the CAA. The NOV contained allegations consistent with NOVs and complaints that the USEPA had brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. DP&L cannot predict the outcome of this matter.

In December 2007, the Ohio EPA issued an NOV to the DP&L-operated Killen generating station (co-owned by DP&L and Duke Energy) for alleged violations of the CAA. The NOV alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received an NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (SIP) and permits for the Station in areas including SO2, opacity and increased heat input. A second NOV and FOV with similar allegations was issued on November 4, 2010. Also in 2010, USEPA issued an NOV to Zimmer for excess emissions. DP&L is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy is expected to act on behalf of itself and the co-owners with respect to these matters. DP&L is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly-Owned Stations
In 2007, the Ohio EPA and the USEPA issued NOVs to DP&L for alleged violations of the CAA at the Hutchings Station. The NOVs' alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. On November 18, 2009, the USEPA issued an NOV to DP&L for alleged NSR violations of the CAA at the Hutchings Station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. DP&L does not believe that the two projects described in the NOV were modifications subject to NSR. DP&L is engaged in discussions with the USEPA and Justice Department to resolve these matters, but DP&L is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

Environmental Matters Related to Water Quality, Waste Disposal and Ash Ponds

Clean Water Act – Regulation of Water Intake
On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act governing existing facilities that have cooling water intake structures. The rules required an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. A number of parties appealed the rules. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA released new proposed regulations on March 28, 2011, which were published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. In July 2012, USEPA announced that the final rules will be released in June 2013. We do not yet know the impact these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, we submitted an application for the renewal of the Stuart Station NPDES permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in a thermal discharge study completed during the previous permit term. Subsequently, DP&L and the Ohio EPA reached an agreement to allow DP&L to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, DP&L provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In

December 2010, DP&L requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. In a letter to the Ohio EPA dated September 28, 2011, the USEPA reaffirmed its objection to the revised permit as previously drafted by the Ohio EPA. This reaffirmation stipulated that if the Ohio EPA does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will pass to the USEPA. The Ohio EPA issued another draft permit in December 2011 and a public hearing was held on February 2, 2012. The draft permit would require DP&L, over the 54 months following issuance of a final permit, to take undefined actions to lower the temperature of its discharged water to a level unachievable by the station under its current design or alternatively make other significant modifications to the cooling water system. DP&L submitted comments to the draft permit. In November 2012, Ohio EPA issued another draft which included a compliance schedule for performing a study to justify an alternate thermal limitation and to which DP&L submitted comments. In December 2012, the USEPA formally withdrew their objection to the permit. On January 7, 2013, Ohio EPA issued a final permit. On February 1, 2013, DP&L appealed various aspects of the final permit to the Environmental Review Appeals Commission. Depending on the outcome of the process, the effects could be material on DP&L's operations.

In September 2009, the USEPA announced that it will be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. Subsequent to the information collection effort, it was anticipated that the USEPA would release a proposed rule by mid-2012 with a final regulation in place by early 2014. In December 2012, USEPA announced that the proposed rule would be released by April 19, 2013 with a deadline for a final rule on May 22, 2014. At present, DP&L is unable to predict the impact this rulemaking will have on its operations.

In August 2012, DP&L submitted an application for the renewal of the Killen Station NPDES permit which expired in January 2013. At present, the outcome of this proceeding is not known.

In April 2012, DP&L received an NOV related to the construction of the Carter Hollow landfill at the Stuart Station. The NOV indicated that construction activities caused sediment to flow into downstream creeks. In addition, the U.S. Army Corps of Engineers issued a Cease and Desist order followed by a notice suspending the previously issued Corps permit authorizing work associated with the landfill. DP&L has installed sedimentation ponds as part of the runoff control measures to address this issue and is working with the various agencies to resolve their concerns including entering into settlement discussions with USEPA, although they have not issued any formal NOV. This may affect the landfill's construction schedule and delay its operational date. DP&L has accrued an immaterial amount for anticipated penalties related to this issue.

Regulation of Waste Disposal

In September 2002, DP&L and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, DP&L and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, DP&L received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to DP&L's service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. DP&L granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against DP&L and numerous other defendants alleging that DP&L and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against DP&L that related to allegations that chemicals used by DP&L at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from DP&L that were allegedly directly delivered by truck to the landfill. Discovery, including depositions of past and present DP&L employees, was conducted in 2012 and may continue throughout 2013. In October 2012, DP&L received a request from PRP group's consultant to conduct additional soil and groundwater sampling on DP&L's service center property. DP&L is complying with this sampling request. On February 8, 2013, the Court granted DP&L's motion for summary judgment on statute of limitations grounds with respect to claims seeking a contribution toward the costs that are expected to be incurred by PRP group in their performing a Remediation Investigation and Feasibility Study. The Court's ruling is likely to be appealed. DP&L is unable to predict the outcome of the appeal. Additionally, the Court's ruling does not address future litigation that may arise with respect to actual remediation costs. While DP&L is unable to predict the outcome of these matters, if DP&L were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

In December 2003, DP&L and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to DP&L does not demonstrate that it contributed hazardous substances to the site. While DP&L is unable to predict the outcome of this matter, if DP&L were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on DP&L. While the USEPA has indicated that the official release date for a proposed rule is sometime in April 2013, it may be delayed until late 2013 or early 2014. At present, DP&L is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds

In March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and Stuart Stations. Subsequently, the USEPA collected similar information for the Hutchings Station.

In August 2010, the USEPA conducted an inspection of the Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the Hutchings Station ash ponds. DP&L is unable to predict whether there will be additional USEPA action relative to DP&L's proposed plan or the effect on operations that might arise under a different plan.

In June 2011, the USEPA conducted an inspection of the Killen Station ash ponds. In May 2012, we received a draft report on the inspection. DP&L submitted comments on the draft report in June 2012. DP&L is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion byproducts including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. Litigation has been filed by several groups seeking a court-ordered deadline for the issuance of a final rule which USEPA has opposed. At present, the timing for a final rule regulating coal combustion byproducts cannot be determined. DP&L is unable to predict the financial effect of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse effect on its operations.

Notice of Violation Involving Co-Owned Units

On September 9, 2011, DP&L received an NOV from the USEPA with respect to its co-owned Stuart generating station based on a compliance evaluation inspection conducted by the USEPA and Ohio EPA in 2009. The notice alleged non-compliance by DP&L with certain provisions of the RCRA, the Clean Water Act National Pollutant Discharge Elimination System permit program and the station's storm water pollution prevention plan. The notice requested that DP&L respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on DP&L's results of operations, financial condition or cash flow.

Legal and Other Matters

In February 2007, DP&L filed a lawsuit against a coal supplier seeking damages incurred due to the supplier's failure to supply approximately 1.5 million tons of coal to two commonly owned stations under a coal supply agreement, of which approximately 570 thousand tons was DP&L's share. DP&L obtained replacement coal to meet its needs. The supplier has denied liability, and is currently in federal bankruptcy proceedings in which DP&L is participating as an unsecured creditor. DP&L is unable to determine the ultimate resolution of this matter. DP&L has not recorded any assets relating to possible recovery of costs in this lawsuit.

In connection with DP&L and other utilities joining PJM, in 2006 the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, DP&L was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports DP&L's and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. Prior to this final order being issued, DP&L entered into a significant number of bilateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. On July 5, 2012, a Stipulation was executed and filed with the FERC that resolves SECA claims against BP Energy Company ("BP") and DP&L, AEP (and its subsidiaries) and Exelon Corporation (and its subsidiaries). On October 1, 2012, DP&L received $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012, there is no remaining balance in other deferred credits related to SECA.

15. Fixed-asset Impairment

On October 5, 2012, DP&L filed for approval an ESP with the PUCO which reflects a shift in our outlook for the regulatory environment. Within the ESP filing, DP&L agreed to request a separation of its generation assets from its transmission and distribution assets in recognition that a restructuring of DP&L operations will be necessary, in compliance with Ohio law. Also, during 2012, North American natural gas prices fell significantly from the previous year, exerting downward pressure on wholesale electricity prices in the Ohio power market. Falling power prices have compressed wholesale margins at DP&L's generating stations. Furthermore, these lower power prices have led to increased customer switching from DP&L to CRES providers, who are offering retail prices lower than DP&L's standard service offer. Also, several municipalities in DP&L's service territory have passed ordinances allowing them to become government aggregators with some having already contracted with CRES providers, further contributing to the switching trend. In September 2012, management revised its cash flow forecasts based on these developments as part of its annual budgeting process and forecasted lower operating cash flows than in prior reporting periods. Collectively, in the third quarter of 2012, these events were considered to be an impairment indicator for the long-lived asset group as management believes that these developments represent a significant adverse change in the business climate that could affect the value of the long-lived asset group.

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. When the recoverability test of the long-lived asset group was performed, management concluded that, on an undiscounted cash flow basis, the carrying amount of two stations, Conesville and Hutchings, were not recoverable. To measure the amount of impairment loss, management was required to determine the fair value of the two stations. Cash flow forecasts and the underlying assumptions for the valuation were developed by management. While there were numerous assumptions that impact the fair value, forward power prices, dark spreads and the transition to a merchant model were the most significant.

In determining the fair value of the Conesville station, the three valuation approaches prescribed by the fair value measurement accounting guidance were considered. The fair value under the income approach was considered the most appropriate and resulted in a $25.0 million fair value. The carrying value of the Conesville station prior to the impairment was $97.5 million. Accordingly, the Conesville station was considered impaired and $72.5 million of impairment expense was recognized in the third quarter of 2012.

In determining the fair value of the Hutchings Station, the three valuation approaches prescribed by the fair value measurement accounting guidance were considered. The fair value under the income approach was considered the most appropriate and resulted in a zero fair value. The carrying value of the Hutchings Station prior to the impairment was $8.3 million. Accordingly, the Hutchings Station was considered impaired and $8.3 million of impairment expense was recognized in the third quarter of 2012.

16. Selected Quarterly Information (Unaudited)

From 2012 onwards, quarterly information is no longer required.

$ in millions except per share amounts and common stock market price	For the 2011 quarters ended March 31	June 30	September 30	December 31
Revenues	$ 449.8	$ 397.0	$ 452.5	$ 378.4
Operating income	$ 89.3	$ 55.8	$ 100.0	$ 74.8
Net income	$ 52.7	$ 30.8	$ 63.9	$ 45.8
Earnings on common stock	$ 52.5	$ 30.6	$ 63.7	$ 45.5
Dividends paid on common stock to DPL	$ 70.0	$ 45.0	$ 65.0	$ 40.0

$ in millions except per share amounts and common stock market price	For the 2010 quarters ended March 31	June 30	September 30	December 31
Revenues	$ 423.8	$ 412.6	$ 472.4	$ 430.0
Operating income	$ 118.4	$ 97.0	$ 131.9	$ 102.9
Net income	$ 72.1	$ 59.4	$ 83.2	$ 63.0
Earnings on common stock	$ 71.9	$ 59.2	$ 83.0	$ 62.7
Dividends paid on common stock to DPL	$ 90.0	$ 60.0	$ -	$ 150.0

17. Cash Flow Statement Items

A. Cash Flow Statement Reconciliation (Instruction 1, p. 120):

	2012 Beginning Balance	2012 Ending Balance
Balance Sheet (p. 110, line 35)	$ 32,246,686	$ 28,548,696
Balance Sheet (p. 110, line 38)	0	0
Cash and Cash Equivalents (p. 121, lines 88 and 90)	$ 32,246,686	$ 28,548,696

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

	2012	2011
Cash paid during the year for:		
Interest (net of amount capitalized)	$ 35,121,336	$ 39,228,016
Income taxes (net of refunds)	$ 61,930,019	$ 13,852,516

C. Statement of Cash Flows

	For the year ended December 31, 2012
Net Cash Flow from Operating Activities:	
Net income	$ 91,122,229
Depreciation and depletion	141,268,487
Taxes applicable to subsequent years	5,200,012
Pension and retire benefits	28,451,817
Deferred income taxes, net	3,556,161
Prepaid taxes	102,337
Investment tax credit adjustment, net	(2,505,492)
Net (increase) decrease in receivables	29,731,331
Net (increase) decrease in inventory	14,243,687
Net increase (decrease) in payables and accrued expenses	(18,612,042)
Net (increase) decrease in other regulatory assets	(1,549,166)
Net increase (decrease) in other regulatory liabilities	67,796
(Less) allowance for other funds used during construction	2,051,975
Fixed-asset impairment	(8,840,993)
Other	80,781,378
Other (deferred debits)	(21,215,475)
Net Cash Provided by (Used In) Operating Activities	339,750,092
Cash Flows from Investment Activities:	
Gross additions to utility plant (less nuclear fuel)	(180,638,500)
Cash outflows from plant	(180,638,500)
Net (increase) decrease in payables and accrued expenses	(14,815,967)
Proceeds from disposal of noncurrent assets	160,391
Net (increase) decrease in restricted cash	2,941,234
Other	(5,114,148)
Net Cash Used in Investing Activities	(197,466,990)
Cash Flows from Financing Activities:	
Payment for retirement of long-term debt	(116,134)
Dividends on preferred stock	(864,958)
Dividends on common stock	(145,000,000)
Net Cash Used in Financing Activities	(145,981,092)
Net increase (decrease) in cash and cash equivalents	(3,697,990)
Cash and cash equivalents at beginning of year	32,246,686
Cash and cash equivalents at end of year	$ 28,548,696

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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	/ /	End of 2012/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	8,409,183	(39,147,239)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(7,835,375)	(5,184,981)		
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)	(7,835,375)	(5,184,981)		
5	Balance of Account 219 at End of Preceding Quarter/Year	573,808	(44,332,220)		
6	Balance of Account 219 at Beginning of Current Year	573,808	(44,332,220)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	426,497	1,983,533		
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)	426,497	1,983,533		
10	Balance of Account 219 at End of Current Quarter/Year	1,000,305	(42,348,687)		

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	12,271,167	(1,790,896)	(20,257,785)		
2	(2,466,811)	1,026,423	(14,460,744)		
3					
4	(2,466,811)	1,026,423	(14,460,744)	193,214,970	178,754,226
5	9,804,356	(764,473)	(34,718,529)		
6	9,804,356	(764,473)	(34,718,529)		
7	(2,466,810)	(3,923,620)	(3,980,400)		
8					
9	(2,466,810)	(3,923,620)	(3,980,400)	91,122,229	87,141,829
10	7,337,546	(4,688,093)	(38,698,929)		

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 1 Column: g

Column g on Page 122b related to power transactions.

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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	/ /	End of 2012/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,950,392,197	4,950,392,197
4	Property Under Capital Leases	898,480	898,480
5	Plant Purchased or Sold		
6	Completed Construction not Classified	289,742,151	289,742,151
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,241,032,828	5,241,032,828
9	Leased to Others		
10	Held for Future Use	2,140,690	2,140,690
11	Construction Work in Progress	87,829,512	87,829,512
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,331,003,030	5,331,003,030
14	Accum Prov for Depr, Amort, & Depl	2,627,331,036	2,627,331,036
15	Net Utility Plant (13 less 14)	2,703,671,994	2,703,671,994
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	-2,577,063,583	-2,577,063,583
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	-50,267,453	-50,267,453
22	Total In Service (18 thru 21)	-2,627,331,036	-2,627,331,036
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)	-2,627,331,036	-2,627,331,036

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	/ /	End of 2012/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
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					10
					11
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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	/ /	End of 2012/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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	62,599,132	14,228,240
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	62,599,132	14,228,240
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,692,640	277,206
9	(311) Structures and Improvements	482,510,526	5,440,276
10	(312) Boiler Plant Equipment	2,037,442,591	44,968,219
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	427,326,751	27,412,498
13	(315) Accessory Electric Equipment	260,438,365	3,474,819
14	(316) Misc. Power Plant Equipment	58,228,707	1,099,420
15	(317) Asset Retirement Costs for Steam Production	10,751,199	37,183
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	3,290,390,779	82,709,621
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	621,310	
38	(341) Structures and Improvements	2,024,311	
39	(342) Fuel Holders, Products, and Accessories	3,957,381	
40	(343) Prime Movers		
41	(344) Generators	84,795,335	531,684
42	(345) Accessory Electric Equipment	2,356,580	115,534
43	(346) Misc. Power Plant Equipment	957,036	243,952
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	94,711,953	891,170
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,385,102,732	83,600,791

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
	-621		76,826,751		4
	-621		76,826,751		5
					6
					7
	-244,670		13,725,176		8
2,486,483	-21,613,173		463,851,146		9
15,980,895	-152,680,789		1,913,749,126		10
					11
860,606	-49,116,473		404,762,170		12
82,236	-6,162,172		257,668,776		13
414,740	-1,191,378		57,722,009		14
	-1,489,435		9,298,947		15
19,824,960	-232,498,090		3,120,777,350		16
					17
					18
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					34
					35
					36
74,782			546,528		37
337			2,023,974		38
			3,957,381		39
					40
-3,683			85,330,702		41
-733			2,472,847		42
-215			1,201,203		43
					44
70,488			95,532,635		45
19,895,448	-232,498,090		3,216,309,985		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	/ /	End of 2012/Q4

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	29,527,549	1,000
49	(352) Structures and Improvements	9,153,097	302,227
50	(353) Station Equipment	177,814,077	12,433,713
51	(354) Towers and Fixtures	29,788,000	30,211
52	(355) Poles and Fixtures	79,004,467	639,270
53	(356) Overhead Conductors and Devices	69,269,340	2,005,967
54	(357) Underground Conduit	508,127	
55	(358) Underground Conductors and Devices	927,007	
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)	396,001,103	15,412,388
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	23,526,416	813,904
61	(361) Structures and Improvements	43,806,140	6,734,003
62	(362) Station Equipment	257,090,981	32,045,499
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	248,345,569	10,208,672
65	(365) Overhead Conductors and Devices	146,202,102	7,303,754
66	(366) Underground Conduit	17,889,878	69,447
67	(367) Underground Conductors and Devices	195,172,449	12,879,320
68	(368) Line Transformers	242,082,916	18,170,244
69	(369) Services	158,797,837	27,402,379
70	(370) Meters	44,785,978	2,732,342
71	(371) Installations on Customer Premises	15,919,804	393,702
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)	1,393,667,520	118,753,266
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	16,336,448	
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment		
90	(393) Stores Equipment	631,006	
91	(394) Tools, Shop and Garage Equipment	7,757,649	272,249
92	(395) Laboratory Equipment	2,094,530	2,769,544
93	(396) Power Operated Equipment	2,266,795	
94	(397) Communication Equipment		
95	(398) Miscellaneous Equipment	1,561,535	45,364
96	SUBTOTAL (Enter Total of lines 86 thru 95)	32,256,844	3,087,157
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)	32,256,844	3,087,157
100	TOTAL (Accounts 101 and 106)	5,269,627,331	235,081,842
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)	5,269,627,331	235,081,842

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	/ /	End of 2012/Q4

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
2,593			29,525,956		48
22,838		-14,481	9,418,005		49
1,463,091		-45,898	188,738,801		50
4,948		-190,780	29,622,483		51
142,158		238,456	79,740,035		52
409,217		-5,525	70,860,565		53
		71,806	579,933		54
		-93,027	833,980		55
			9,439		56
					57
2,044,845		-39,449	409,329,197		58
					59
			24,340,320		60
470,841		14,484	50,083,786		61
5,348,619		-627,293	283,160,568		62
					63
273,366		-53,344	258,227,531		64
766,820		16,783	152,755,819		65
		-2,236,402	15,722,923		66
1,039,084		808,449	207,821,134		67
452,706		2,046,224	261,846,678		68
89,684			186,110,532		69
417,110			47,101,210		70
12,053			16,301,453		71
			47,450		72
					73
					74
8,870,283		-31,099	1,503,519,404		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,608,881		86
			16,336,448		87
					88
					89
101,612			529,394		90
122,490			7,907,408		91
76,425		70,548	4,858,197		92
27,621			2,239,174		93
					94
38,910			1,567,989		95
367,058		70,548	35,047,491		96
					97
					98
367,058		70,548	35,047,491		99
31,177,634	-232,498,711		5,241,032,828		100
					101
					102
					103
31,177,634	-232,498,711		5,241,032,828		104

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	/ /	End of 2012/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 East Bend 627.369 Acres	1/10/1981	**	588,046
6				
7	Parcels of Land at Stuart Station	1/1/1999	**	630,357
8				
9	N. Beavercreek Sub Station	1/1/1997	**	494,100
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				
37				
38	(*) Amounts were recorded on Account 101 on			
39	Respondent's books prior to 1970			
40				
41	(**) Various dates			
42				
43				
44				
45				
46				
47	Total			2,140,690

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRODUCTION - Zimmer (*)	
2	Auxiliary Boiler Conversion	761,483
3	Sequence 4/5 Landfill	444,268
4	Valve	142,833
5	Replace 3rd Layer Catalyst	94,480
6	Mercury Control Process	85,849
7	Mag Injection System Upgrade	31,985
8	Lime Inerts Dewatering	27,294
9	Performance Monitoring	25,327
10	Burners - Phase 1	24,889
11	Minor Projects	20,426
12		
13	PRODUCTION - Stuart (*)	
14	Elk Run Engineering, Design, Permitting	4,026,622
15	Pendant Reheater - Unit 4	1,582,010
16	Damaged Claims - Boiler and Turbine Failure	1,016,750
17	Jet Bubbling Reactor Upgrade and Sparger Tube Replacement - Unit 1	380,544
18	Precipitator Switched Mode Power Supplies - Unit 2	378,274
19	DCS Upgrade - NERC	336,266
20	Waterwalls - Unit 4	289,539
21	Jet Bubbling Reactor Internal Support Upgrade and Sparger Tubes - Unit 3	260,517
22	Coal Handling Stacker Tower Elevator	231,068
23	Erosion Protection Landfill 9 Retention Pond	206,087
24	Prerequisites NERC/CIP V4 Implementation	198,041
25	Breaker Room Positive Pressure	162,820
26	Gas Cooling Duct Lining - Unit 4	153,542
27	SCR Catalyst Replacement - Unit 1	152,002
28	FGD Air Line and Compressor Move	151,338
29	Main Turbine Hydrogen Purity Modification	127,192
30	Generator Field Rewind - Unit 3	124,919
31	Boiler Feed Pump Recirculation Valve Replacement - Unit 4	115,129
32	Archaeological Study Baldwin & Elk Creek Run Crossing	113,315
33	Cracker Pit Grating	107,519
34	Boiler Feed Pump Turbine Rebuild	94,345
35	Stuart Station Polisher Upgrade	90,834
36	Landfill Development	88,449
37	Uploader Buckets and Chains	81,868
38	Turbine Overhaul - Unit 3	78,830
39	Sootblower Set - Unit 4	61,430
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,829,512

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	/ /	End of 2012/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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRODUCTION - Stuart (*) (Cont'd)	
2	Landfilling Activities	60,794
3	Boiler Feed Pump Turbine Nozzle Box	59,966
4	Boiler Feed Pump Recirculation System - Unit 1	56,750
5	Oxidation Air Saturation Water Piping - Unit 4	49,079
6	Sootblower Set - Unit 2	46,504
7	Festoon Cables for East/West Gallary	44,018
8	Battery Tray Grounding and Transfer Switches	43,161
9	Jet Bubbling Reactor Prequench Piping - Unit 4	39,161
10	Jet Bubbling Reactor Prequench Piping - Unit 1	38,006
11	Conveyor Belts	32,511
12	Boiler Water Quality Upgrade - Unit 1	30,057
13	3 Way Valves - Unit 4	28,487
14	String HP Inlet/Outlet Valves - Unit 4	26,580
15	Boiler Oxygen Probes - Unit 4	26,004
16	Boiler Water Quality Upgrade - Unit 3	22,997
17	Gas Cooling Inlet Expansion Joint - Unit 4	21,741
18	Boiler Water Quality Upgrade - Unit 4	21,492
19	Gas Cooling Quench Upgrade - Unit 4	20,892
20	Pumps	20,157
21	Boiler Water Quality Upgrade - Unit 2	20,063
22	Boiler Feed Pump Recirculation System - Unit 3	19,740
23	Building Vent Fans	18,848
24	Heater String Outlet Valve - Unit 2	18,672
25	Coal Sample Screw Conveyor	17,451
26	Valves	16,636
27	Relays	15,288
28	Pendant Reheater Replacement - Unit 4	14,426
29	Boiler Observation Doors - Unit 1	12,856
30	Boiler Feed Pump Recirculation Valve Replacement - Unit 2	11,323
31	Control Cables	10,576
32	Remote Racking Power Unit	8,758
33	HVAC	7,912
34	Turbine Lube Oil Cooler Bundle	7,739
35	Gauges and Instruments	7,647
36	Boiler Feed Pump Rotating Assembly	7,644
37	Automotive and Power Operated Work Equipment	7,146
38	Non-Return Valve - Unit 2	7,094
39	Low NOx Burners - Unit 3	6,614
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRODUCTION - Stuart (*) (Cont'd)	
2	Crusher Assembly	6,564
3	Remote Transmitting Units Install - Units 1-4	5,680
4	Motor Control	5,528
5	Expansion Joints	4,996
6	Pulverizer Classifier	4,963
7	Gypsum Load Out Hopper	4,605
8	Portable Radios	3,876
9	Sootblower Set - Unit 1	3,810
10	Security System	3,765
11	Auxiliary Boiler Level Transmitter Install	3,246
12	Cooler Bundle	3,211
13	Misc Tools and Work Equipment	3,154
14	Transformer	3,011
15	Jet Bubbling Reactor Sparger Grid Access Door - Unit 2	2,967
16	Panels, Instrument, Gauge and Control	2,801
17	Pump Replacement	2,376
18	Control Panels	2,078
19	Pipe	2,032
20	Training Equipment	2,002
21	Motors	1,964
22	Hydro Jet Heat Flux Install - Unit 1	1,937
23	Fire Equipment	1,823
24	Platforms	1,783
25	Arc Flash Reduction Upgrade	1,601
26	Building Improvements	1,591
27	Software	1,591
28	Storage Tanks	1,450
29	Boiler Doors	1,204
30	Control Cabinet	1,156
31	Plant Computer System	1,126
32	Circuit Breakers	965
33	Computer Hardware	856
34	Gearbox	587
35	Spare Turbine Blades	540
36	Manchester Training Facility	407
37	Minor Projects	478
38	Non-Return Valve - Unit 2	390
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,829,512

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRODUCTION - Killen (*)	
2	Waste Water Pump Replacements	1,088,959
3	Combustion Turbine Pollution Control	860,785
4	Evergreen Upgrade	741,309
5	Turbine Overhaul	577,078
6	Excitation Control System Replacement	512,059
7	Simulator Upgrade	483,692
8	Valves and Drain Line	122,178
9	Main Turbine Overspeed Trip System	90,987
10	Sump Pump	88,478
11	Turbine Supervisory Instrumentation Upgrade	87,458
12	Building Improvements	67,286
13	Pump	43,709
14	Tools	38,733
15	Cable Power	32,199
16	Makeup Water to Humidification	28,613
17	Generator Field Rewind	21,195
18	Generation Microwave Upgrade	20,467
19	Conveyor, Belt	18,810
20	Pipe	14,746
21	Motor	12,911
22	Valve	11,333
23	Radios	10,818
24	FGD Platforms, Hand Rails and Grating	10,248
25	Chutes, Coal	10,079
26	Switchyard - Three 345KV Breakers	8,215
27	Panel, Electrical	7,389
28	HVAC	4,496
29	Electrical	3,150
30	DCS Controls	2,085
31	Control Room	1,823
32	Joint, Expansion	1,687
33	Minor Projects	351
34		
35	PRODUCTION - Conesville (*)	
36	Jet Bubbling Reactor Retrolift Conesville	3,079,150
37	Turbine Upgrade	2,231,000
38	FGD Landfill	1,080,309
39	Coal Pipe Replacement	848,567
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,829,512

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRODUCTION - Conesville (*) (Cont'd)	
2	GSU Replacement	817,710
3	Coal Dust Collection Replacement	584,839
4	FGD Process Improvement	242,492
5	Hydrogen Cooler Upgrade Replacement	225,779
6	SCR Catalyst 4th Layer Addition	193,469
7	Fan Blade Purchase	151,468
8	Bottom Ash Line Replacement	143,354
9	Conveyor Replacement	113,696
10	Burner Coal Tip Replacement	113,321
11	Arc Flash Safety System - Main	108,677
12	Fan Stationary Replacement	88,350
13	Mill Grind Zone Replacement	86,131
14	Boiler Infrared Camera System	79,834
15	Wall Reclaim Landfill - Phase 1	70,747
16	Chemical Feed System Replacement	60,570
17	Boiler Feed Pump Rotor Replacement	58,704
18	FGD Ball Mill Loader Purchase	49,610
19	Dry Fly Ash Controls Replacement	41,811
20	Precip Plates & Wires Replacement	40,408
21	Annunicator System Replacement	36,709
22	River Intake Valve Replacement	33,736
23	FGD Arc Flash Safety System	30,262
24	Ball Mill Motor Purchase	29,884
25	Inner/After Cooler Replacement	26,352
26	Reclaim Vibratory Feeder Replacement	25,049
27	Gearbox Replacement	22,032
28	HVAC Chiller Replacement	21,595
29	Fan Rotating Blade Replacement	21,111
30	Spare Boiler Feed Pump Turbine Rotor Blade Replacement	18,497
31	Jet Bubbling Reactor Sump Pumps Replacement	15,978
32	Coal Handling Replacement	14,249
33	Wireless Ground Detector	13,179
34	Ball Mill Gear Box Purchase	12,706
35	Highwall Reclamation Landfill	4,190
36	Turbine Oil Reservoir Pressure Transmitter	3,037
37	FGD Ball Mill Lifting Device Purchase	1,637
38	Tank Flow Transmitter	1,509
39	Minor Projects	506
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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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	Lawrenceburg Rd Landfill Area 3A	2,940,983
3	Reclaim Pit Feeder Replacement	169,742
4	Performance Monitoring	48,025
5	Asbestos Abatement Replacement	8,666
6	Precip Penthouse Heating System	2,746
7	Landfill Closure Phase 1	380
8		
9	PRODUCTION - East Bend (*)	
10	Install Stack Lining	943,305
11	Pendant Replacement	704,610
12	Baghouse Retrofit	431,988
13	New Sulfuric Acid System	156,335
14	Pulverizer Roll Wheel Replacement	59,872
15	Replace Sewage Treatment Plant	59,070
16	Unit Control Simulator	50,598
17	Replacement Emergency Pond Pumps	46,632
18	Ash Pond Modification	37,115
19	IT Capital Project Support	31,703
20	Gearbox Oil Filter	30,536
21	Replacement Flyash and Lime Scales	29,932
22	Umbilical Replacement	24,015
23	Replace Transfer Tower Fire Detective System	23,321
24	Sump Pump	20,998
25	Fuel Oil Tank Dike Liner Replacement	17,748
26	Pump Breaker - Phase 1	15,258
27	Cable Reel and Drive	12,141
28	Air Compressor Cooler	9,008
29	Replacement Pump Breakers - Phase 2	5,670
30	Study Ash Pond Liner	5,149
31	Ash Slice Pump Seal Water Pipe	4,943
32	HVAC Replacement	2,561
33	Filtrate Return Pumps	1,462
34	Aro-Cooling Tower	726
35	Pulverizer Gearbox Replacement	85
36		
37		
38		
39		
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
43	TOTAL	87,829,512

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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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 - Beckjord (*)	
2	Mercury Monitoring System	306,577
3	Replace Hydrogen Coolers	54,363
4	Mercury Monitoring System CWIP Tracker	11,056
5	Misc Asbestos Abatement	1,788
6		
7	PRODUCTION - Other	
8	Yankee Start Controls	253,004
9	Minor Projects	53,681
10	Tait and Yankee Combustion Turbines Calibration & Test Equipment	46,376
11		
12	DISTRIBUTION	
13	Pole Replacement	3,898,223
14	North Dayton Service Center Expansion and Remodel	2,010,667
15	Planned Replace - Distribution	1,974,152
16	Underground Reliability Program	1,931,442
17	4KV Distribution Upgrade to 12KV	1,697,422
18	Cutout Capitalization Project	1,653,460
19	Damaged Claims - Transformer Failure	1,649,758
20	Call Center Telecom System	1,519,187
21	Meter Installation Cost	1,368,091
22	New Residential Services	1,302,029
23	CCEM - Two-Way Voice and Data System	858,689
24	Substations Repair	845,020
25	Call Center Recording System	781,502
26	CCEM - Microwave Backhaul System	664,085
27	Tait 12KV Circuit - Aviation Building	651,948
28	WPAFB Install Scada System	564,255
29	Transformer Install Cost	511,671
30	Spare Substation/Electrical Test Equipment	478,616
31	Overhead Reliability Program	412,919
32	Greenville Reconductor	375,751
33	Troy, New Bridge Cable Relocation	366,888
34	WPAFB-69KV Oil Skid Containment Tank	317,069
35	WPAFB Pilot Wire	310,603
36	Reliability Action Plan	289,479
37	Troy, Bridge Cable Relocation	268,343
38	Metering Equipment	193,379
39	12KV Distribution Capacitors	192,811
40		
41	(*) Respondent's portion of undivided ownership in generating facilities with Duke Energy	
42	Ohio, Inc. and/or Columbus Southern Power.	
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION (Cont'd)	
2	WPAFB SPCC Plans for 9 Substations	182,240
3	WPAFB Emergencies Under $100K	174,172
4	Cable Replacement	165,920
5	El Monitor Elimination Program	155,629
6	Eaker Sub - 12KV Breaker Replacement	124,484
7	Indian Lake Reconductor	100,897
8	Substation Fence Repair	94,369
9	ODOT - Facilities Relocation	58,395
10	Install Elec Remote Transmitting Unit - Glenn Karn Gas Interconnect Facilities	57,041
11	Wilmington - Facilities Relocation	54,573
12	WPAFB Transformer Install Cost	40,548
13	Substation - Security Cameras and Grounding	39,343
14	Substation Battery Replacement Program	23,588
15	Rebuild Capacitor Breakers	20,947
16	Dayton Mall Circuit Mainline Repair	20,565
17	New 12KV Capacitors	19,533
18	WPAFB - Replace Battery Substation	18,322
19	Regulators and Reclosures	18,164
20	Overhead Reliability Plan	15,767
21	Cable Replacement on Main Line Cables	14,930
22	Vandalia - New 12KV Circuit Split	13,099
23	Wilmington - Reconductor	9,878
24	WPAFB - Substation Tie Cable Faults	5,594
25	Install Elec Remote Transmitting Unit - Derby Gas Interconnect Facilities	5,540
26	Install Elec Remote Transmitting Unit - Centerville Gas Interconnect Facilities	5,304
27	WPAFB - Building - New Electric Facilities	4,020
28	12KV Distribution Capacitors	3,103
29	Carpenter Substation - New Circuit	2,987
30	Minor Projects	2,635
31		
32	TRANSMISSION	
33	Lidar - NERC Facility Rating	2,004,275
34	Zimmer Transmission	1,075,272
35	Conesville Transmission	800,380
36	Metro Substations - Security - Cameras and Grounding	624,804
37	Zimmer Gas Bus Replacement	607,388
38	Beckjord Transmission	419,903
39	Transmission Switch Sectionalizer Replacement - Phase 2	316,578
40	Western Substations - Security - Cameras and Grounding	200,387
41	Forced Repair - Transmission Substations	162,955
42	Circuit 6663 Celina-St. Marys 69KV Relays	154,155
43	TOTAL	87,829,512

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	TRANSMISSION (Cont'd)	
2	PJM Regional Transmission Expansion Plans - 345/69KV Substation - Marysville	143,680
3	Relay Trip Testing Switches - NERC Requirement	136,929
4	Digital Relays - Seven 138KV Lines	124,223
5	Online Transformer Monitoring Equipment - Phase 2	81,368
6	West Milton Substation	77,038
7	Conesville Transmission - Hyatt	75,135
8	Transmission Spare 138/69KV Transformer	63,307
9	Lidar Remediation - NERC Verification - Phase 1	57,817
10	PJM Regional Transm Exp Plan - Bath to Trebein Reconductor - Circuit 138	51,996
11	PJM Regional Transm Exp Plan - West Milton-Salem-Englewood Reconductor	48,730
12	Minor Projects	47,737
13	Online Transformer Monitoring Equipment - Phase 3	45,746
14		
15	GENERAL	
16	CSS-PIPP Reform Phase 2	2,014,708
17	MacGregor Park Building Remodel - Phase 1	1,693,679
18	MacGregor Park Building Remodel - Phase 2	1,660,509
19	North Dayton Garage Expansion	1,507,076
20	CSS - Bill Ready Billing Enhancement	1,504,963
21	EBS Application Upgrade Research and Testing	1,309,420
22	North Dayton Service Center Remodel	955,457
23	Responsible Diesel Generators Rice Emissions Compliance	906,323
24	Greenville Service Center Remodel	757,157
25	Telephone System Upgrade - AVAYA	750,377
26	NERC CIP Version 4	517,812
27	Tait CT #2 Liner Sleeves	476,480
28	Accounts Payable Document Imaging - Phase 2	474,793
29	MacGregor Park Employee Entrance and Lobby Security	473,479
30	Desktop Upgrades	407,412
31	CSS Mainframe Software Upgrade	330,816
32	GIS Database Expansion - New Landbase and Conflation	271,276
33	Office Furniture and Equipment	255,665
34	Wireless Access Implementation	221,323
35	Structures and Improvements	180,356
36	Tools Shop and Garage Equipment	174,030
37	Field Collection System	150,318
38	CSS Enhancements for Aspect IVR Upgrade	112,533
39	Hot Stick Tester and Controller	110,746
40	Greenville Pole Yard	92,180
41	CSS Email Address and Ebill Indicator Enhancement	89,742
42	Security Infrastructure and Software	60,700
43	TOTAL	87,829,512

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	/ /	End of 2012/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 (Cont'd)	
2	WAM Schedule and Reporting Upgrade	52,447
3	Transportation Equipment	52,007
4	Dispatch Admin Database (DAD) Upgrade	34,365
5	AES to DPL Routers for MPLS Circuits	31,974
6	Network and Communication Equipment Refresh	28,440
7	Misc Equipment	28,040
8	REVE/Datamart Upgrade project	27,011
9	Minor Projects	16,452
10	CSS Accounts Receivable Reports Enhancements	14,679
11	GIS Data Editing Tool	10,925
12	Energy Vision Enhancement for Bid Process	10,666
13	IT - Outage Management System	9,598
14		
15	UNALLOCATED CONSTRUCTION OVERHEADS	-1,577,967
16		
17		
18		
19		
20		
21		
22		
23		
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26		
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42		
43	TOTAL	87,829,512

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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	/ /	End of 2012/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 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	-2,636,597,703	-2,636,597,703		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	-214,735,856	-214,735,856		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-354,739	-354,739		
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)	-215,090,595	-215,090,595		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	-31,175,041	-31,175,041		
13	Cost of Removal	-10,928,300	-10,928,300		
14	Salvage (Credit)	-350,594	-350,594		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	-41,752,747	-41,752,747		
16	Other Debit or Cr. Items (Describe, details in footnote):	232,871,968	232,871,968		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	-2,577,063,583	-2,577,063,583		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	-1,576,356,534	-1,576,356,534		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	-71,820,858	-71,820,858		
25	Transmission	-222,008,453	-222,008,453		
26	Distribution	-682,224,552	-682,224,552		
27	Regional Transmission and Market Operation				
28	General	-24,653,186	-24,653,186		
29	TOTAL (Enter Total of lines 20 thru 28)	-2,577,063,583	-2,577,063,583		

Name of Respondent The Dayton Power and Light Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

1.	Generation fixed asset impairments to reserves	$160,459,825
2.	Adjustments to fair market value to dep exp	80,781,378
3.	Gen plant impairments to dep exp	(8,869,684)
4.	Fuel deferral in dep exp not in accum prod	(43,604)
5.	Logicalis lease to 1110000 from distribution	299,463
6.	Intangible adjustments	244,590
		$232,871,968

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	/ /	End of 2012/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	80,947,408	65,585,127	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)	12,756,125	14,088,623	All
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	27,440,265	32,771,717	Electric
8	Transmission Plant (Estimated)	976	3,668	Electric
9	Distribution Plant (Estimated)	6,739,736	3,489,801	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)	46,937,102	50,353,809	
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)	1,740,663	1,881,095	All
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	129,625,173	117,820,031	

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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	/ /	End of 2012/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)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	76,936.00		72,525.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
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	71,598.00			
19	Other:				
20	Adj to Inventory Balance	-6,049.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	11,387.00		72,525.00	
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	1,041.00		1,041.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,041.00			
40	Balance-End of Year			1,041.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,041.00	699		
45	Gains	1,041.00	699		
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	/ /	End of 2012/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.

2014		2015		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
72,525.00		72,525.00		1,885,650.00		2,180,161.00		1
								2
								3
				72,525.00		72,525.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						71,598.00		18
								19
						-6,049.00		20
								21
								22
								23
								24
								25
								26
								27
								28
72,525.00		72,525.00		1,958,175.00		2,187,137.00		29
								30
								31
								32
								33
								34
								35
1,035.00		1,037.00		50,928.00		55,082.00		36
				2,079.00		2,079.00		37
								38
				1,049.00		2,090.00		39
1,035.00		1,037.00		51,958.00		55,071.00		40
								41
								42
								43
				1,049.00	137	2,090.00	836	44
				1,049.00	137	2,090.00	836	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	/ /	End of 2012/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.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	17,543.00		19,005.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	754.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchase-Duke Energy	1,000.00	37,500		
10	Purchase-Alliant Energy	1,500.00	60,750		
11					
12					
13					
14					
15	Total	2,500.00	98,250		
16					
17	Relinquished During Year:				
18	Charges to Account 509	19,736.00	45,181		
19	Other:				
20	Adj to Inventory Balance	-12.00			
21	Cost of Sales/Transfers:				
22	Transf Assoc Electric	590.00			
23					
24					
25					
26					
27					
28	Total	590.00			
29	Balance-End of Year	483.00	53,069	19,005.00	
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	/ /	End of 2012/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.

2014		2015		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
19,005.00						55,553.00		1
								2
								3
						754.00		4
								5
								6
								7
								8
						1,000.00	37,500	9
						1,500.00	60,750	10
								11
								12
								13
								14
						2,500.00	98,250	15
								16
								17
						19,736.00	45,181	18
								19
						-12.00		20
								21
						590.00		22
								23
								24
								25
								26
								27
						590.00		28
19,005.00						38,493.00	53,069	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
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								40
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								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	/ /	End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Feasibility Study, Wilmington 69kv			(3,100)	5610006
3					
4	Impact Study, Wilmington 69kv			(3,800)	5610006
5					
6	Feasibility/Impact Study			(4,200)	5610006
7					
8	Feasibility Study, Hursch Rd. 69kv			(1,300)	5610006
9					
10	Feasibility Study, Shelby-SW			(5,200)	5610006
11					
12	Impact Study, W. Milton 138kv			(5,500)	5610006
13					
14	345kv Feasibility Study			(5,200)	5610006
15					
16	345kv Impact Study			(5,400)	5610006
17					
18	138kv Impact Study			(1,700)	5610006
19					
20	12kv Facility Study			(11,224)	5610006
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
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32					
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40					

Schedule Page: 231 Line No.: 2 Column: a
V3-013 RE Wilmington Solar 1, LLC

Schedule Page: 231 Line No.: 4 Column: a
See footnote 231, Line 2, Column a

Schedule Page: 231 Line No.: 6 Column: a
W4-035 Lincoln Renewable Energy LLC

Schedule Page: 231 Line No.: 8 Column: a
X2-077 The ERORA Group

Schedule Page: 231 Line No.: 10 Column: a
US Mainstream Renewable Power Inc.

Schedule Page: 231 Line No.: 12 Column: a
Apex Wind Energy Holdings, LLC Greenville

Schedule Page: 231 Line No.: 14 Column: a
American Municipal Power Inc. Zimmer-Spurlock

Schedule Page: 231 Line No.: 16 Column: a
See 231, Line 14, Column a

Schedule Page: 231 Line No.: 18 Column: a
NextEra Energy Resources, LLC Amsterdam

Schedule Page: 231 Line No.: 20 Column: a
OneEnergy Greenville, LLC Greenville

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	/ /	End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Station Emission Fees	4,805,170	1,522,617	930.2	6,327,787	
2	FASC 740 - Electric	26,396,995	15,393,407	283, 283	5,276,921	36,513,481
3	Consumer Education Campaign	3,037,342	1,450			3,038,792
4	Regional Transmission Organization Costs	4,051,972		581.4	1,473,445	2,578,527
5	Retail Settlement System Costs	3,067,358				3,067,358
6	Unrealized Loss - Pension and Retiree	92,052,355	5,344,702	410.1, 926	8,521,174	88,875,883
7	CCEM Smart Grid & Advanced Metering Infrastructure	6,579,337	83,796	421	27,870	6,635,263
8	CCEM Energy Efficiency Program	8,896,962	5,651,047	421, 580,	9,334,618	5,213,391
9				907, 908,		
10				909, 910,		
11				920, 923		
12	Deferred Windstorm Costs	17,939,435	6,521,616		101,938	24,359,113
13	TCRR, Trans, Ancillary & Other PJM-Related Costs	5,301,526	4,492,863	421, 555,	3,873,303	5,921,086
14				556		
15	Fuel Deferral	8,209,891	37,942,815	Various	34,884,356	11,268,350
16	Renewable Energy - Electric Security Plan	3,460,214	5,171,389	421, 920	4,892,318	3,739,285
17				930		
18	Other Regulatory Assets	991,850	9,072,049	Various	7,994,840	2,069,059
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL :	184,790,407	91,197,751		82,708,570	193,279,588

Schedule Page: 232 Line No.: 1 Column: a

Represents costs paid to the State of Ohio since 2002 for environmental monitoring. An application was pending before the PUCO to amend an approved rate rider that had been in effect to collect fees that were paid and deferred in years prior to 2002. The deferred costs incurred prior to 2002 have been fully recovered. On October 6, 2011, we reached a stipulation with parties in our fuel proceeding. As part of that stipulation, the PUCO staff as well as other signatory parties agreed to allow DP&L to include these costs in our fuel rider for 2012. The PUCO approved the stipulation on November 9, 2011. As a result, DP&L removed the emission fee rider from customer bills and included this cost as part of the fuel rider starting on December 1, 2011.

Schedule Page: 232 Line No.: 2 Column: a

Represents 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. These items are offset by balances in Account 282 ($23,733,763) and Account 283 ($12,779,719).

Schedule Page: 232 Line No.: 3 Column: a

Costs include consumer education advertising regarding electric deregulation. DP&L will be seeking recovery of these costs as part of our next distribution rate case filing at the PUCO. The timing of such a filing has not yet been determined.

Schedule Page: 232 Line No.: 4 Column: a

Represents costs incurred to join a Regional Transmission Organization (RTO). In accordance with FERC precedence, we are amortizing these costs over a 10-year period that began in 2004 when we joined the PJM RTO. The recovery of these costs will be requested in a future FERC rate case.

Schedule Page: 232 Line No.: 5 Column: a

Represents costs related to implement a retail settlement system that reconciles the amount of energy a Competitive Retail Electric Service (CRES) supplier delivers to its customers and with what its customers actually use. Based on case precedent in other utilities' cases, the costs are recoverable through a future DP&L rate proceeding.

Schedule Page: 232 Line No.: 6 Column: a

Represents 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 Other Comprehensive Income (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.

Schedule Page: 232 Line No.: 7 Column: a

Represents costs incurred as a result of studying and developing distribution system upgrades and implementation of Advanced Metering Infrastructure (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. DP&L plans to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Schedule Page: 232 Line No.: 8 Column: a

Represents costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider that began July 1, 2009 and that is subject to a two-year true-up for any over/under recovery of costs. On April 29, 2011, DP&L filed to true-up the EER which was approved by the PUCO on October 18, 2011. DP&L plans to make its next true-up filing on or before April 30, 2013.

Schedule Page: 232 Line No.: 12 Column: a

Represents costs incurred to repair the damage caused by storms in the following years:

2008 - Related to costs incurred to repair damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted DP&L the authority to defer these costs with a return until such time that DP&L seeks recovery in a future rate proceeding.

2011 - Related to five major storms in 2011. On December 21, 2012, DP&L filed a request with the PUCO for an accounting order to defer costs and a request for recovery of costs associated with these storms. DP&L believes the recovery of these costs is probable at December 31, 2012.

2012 - Related to storm damage that occurred during the final weekend of June 2012. On August 10, 2012, DP&L filed a request with the PUCO, which was modified on October 19, 2012, for an accounting order to defer the costs associated with this storm damage. On December 19, 2012, the PUCO issued an order permitting partial deferral.

On December 21, 2012, DP&L filed a request for recovery of all of these deferred storm costs with the PUCO.

Schedule Page: 232 Line No.: 13 Column: a

Represents costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. Retail rates are adjusted annually to true-up costs with recovery in rates.

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

Represents 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. DP&L implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. We received the audit report for 2011 on April 27, 2012. The auditor has recommended that the PUCO consider reducing DP&L's recovery of fuel costs by approximately $3.4 million from certain transactions. On October 4, 2012, DP&L filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

Schedule Page: 232 Line No.: 16 Column: a

Represents costs associated with evaluating the Company's options, purchasing power or Renewable Energy Credits (RECs), or participating in the alternative energy project targeted in Ohio SB 221. As part of DP&L's October 10, 2008 ESP filing, the Company included an Alternative Energy Plan that describes the Company's plans to meet the Alternative Energy and Renewable Energy portfolio targets outlined in SB 221. There will be ongoing costs assigned to this account and the amortization rate will be consistent with the Alternative Energy Rider (AER) rate. On June 24, 2009, the Commission issued an order approving the ESP Stipulation as filed. We began recovery of AER costs on June 30, 2009. These costs are subject to an annual true-up process.

Schedule Page: 232 Line No.: 18 Column: a

Represents other regulatory assets which primarily include other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

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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	/ /	End of 2012/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Property Taxes (1)	71,882,500	70,432,511	408.1	75,632,523	66,682,488
2						
3	Trust Assets	10,195,767	2,009,702	131, 228	1,761,702	10,443,767
4						
5	Refundable Tax Benefit from					
6	Contrib. in Aid of Const. (2)	160,205		456	23,416	136,789
7						
8	Payroll Advances	33,091	2,945,647	Various	2,989,904	-11,166
9						
10	Patriot Coal Settlement (3)	700,758		151	700,758	
11						
12	ESP Stipulation (4)	1,040,408	4,045	928	1,044,453	
13						
14	Other	-5,426	232,869	Various	170,002	57,441
15						
16						
17						
18						
19						
20	(1) Amortized over 12 months					
21	(2) Amortized through 2018					
22	(3) Amortized through 2012					
23	(4) Amortized through 2012					
24						
25						
26						
27						
28						
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34						
35						
36						
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45						
46						
47	Misc. Work in Progress	4,570,741				5,829,738
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	88,578,044				83,139,057

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	/ /	End of 2012/Q4

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	26,031,376	19,516,856
3	Union Disability	4,893,593	4,890,151
4	Post Retirement Benefits	8,290,241	8,048,392
5	Deferred Compensation	3,839,187	1,463,514
6	FAS 109 - Electric	12,232,361	10,871,186
7	Other	8,757,258	5,494,627
8	TOTAL Electric (Enter Total of lines 2 thru 7)	64,044,016	50,284,726
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	92,108	27,200
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	64,136,124	50,311,926

Notes

	Beginning Balance	Ending Balance
(1) L. 7, Col. b&c, Other		
FERC Federal	29,205	23,266
Vacation Accrual	1,703,289	1,978,382
Book Capitalization of Construction Period Net Earnings	96,615	85,263
State Income Taxes	2,911,676	2,002,059
Employee Stock Options	987,269	436,238
Short-Term Bad Debt Expense	329,410	(200,568)
ESOP	78,511	104,743
Insurance Claims Reserve	(1,611,817)	(1,611,817)
Accrued Employee Taxes	207,207	207,207
Ohio Kwh Tax Accrual	802,501	(83,049)
Capitalized Interest Income	3,298,735	2,949,058
Deferred Interest on Future Tax Impacts	0	(784,462)
Federal Deferred Tax on Non-Deductible State Tax	(84,305)	396,164
Deferred Litigation Costs	0	(16,819)
Other	8,962	8,962
(2) L. 17, Col. b&c, Other		
FAS 109 - Non utility	64,908	0
Other	27,200	27,200

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	/ /	End of 2012/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

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	---			
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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
65,380	6,538,000					12
						13
228,058	22,805,800					14
						15
						16
						17
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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	/ /	End of 2012/Q4

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	-1,308,481
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	-1,146,591
23		
24	Account 211 - Miscellaneous Paid-In Capital	
25		
26	Balance at Beginning of Year	229,309,813
27	Other Paid-In Capital from Parent	
28	Other Paid-In Capital Related to Equity Awards	
29	Other Paid-In Capital - Other	
30		
31	Subtotal 211 - Balance at End of Year	229,309,813
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	515,956,712

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		
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22	TOTAL	16,716,891

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	/ /	End of 2012/Q4

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	5.125% due 2013 (PUCO Case #03-1297-EL-AIS dated 7/24/03)	470,000,000	4,354,201
6	5.125% due 2013 (PUCO Case #03-1297-EL-AIS dated 7/24/03) (D)		1,818,900
7	4.7% - due 2028 (PUCO Case #05-767-EL-AIS dated 8-10-05)	35,275,000	714,175
8	4.8% - due 2034, Air Quality (PUCO Case #05-767-EL-AIS dated 8-10-05)	137,800,000	2,434,983
9	4.8% - due 2034, Water (PUCO Case #05-767-EL-AIS dated 8-10-05)	41,300,000	879,778
10	4.8% - due 2036, Series A (PUCO Case #06-758-EL-AIS dated 7-26-06)	100,000,000	1,781,846
11	Variable Rate Series Due 2040 (PUCO Case #08-0165-EL-AIS dated 2-28-08)	100,000,000	1,614,956
12			
13	Guaranty of Air Quality Development		
14	Obligation, Series:		
15			
16			
17	Subtotal Account 221 - Bonds	884,375,000	13,598,839
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			
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31			
32			
33	TOTAL	903,066,000	13,598,839

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	/ /	End of 2012/Q4

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
09/03	10/13	10/01/03	09/30/13	470,000,000		5
						6
08/05	01/28	08/17/05	12/31/27	35,275,000		7
08/05	01/34	08/17/05	12/31/33	137,800,000		8
08/05	01/34	08/17/05	12/31/33	41,300,000		9
09/06	09/36	09/13/06	08/31/36	100,000,000		10
12/08	11/40	12/04/08	10/31/40	100,000,000		11
						12
						13
						14
						15
						16
				884,375,000		17
						18
						19
						20
						21
						22
						23
03/11	03/61	03/01/11	02/28/61	18,481,738		24
						25
						26
						27
						28
						29
						30
						31
						32
				902,856,738		33

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

Issued as security of $35,275,000 principal amount of Ohio Air Quality Development Authority Bonds, 4.7% due 2028.

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

Issued as security of $137,800,000 principal amount of Ohio Air Quality Development Authority Bonds, 4.8% due 2034.

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

Issued as security of $41,300,000 principal amount of Ohio Water Development Authority Bonds, 4.8% due 2034.

Schedule Page: 256 Line No.: 10 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.: 11 Column: a

Issued as security of $100,000,000 principal amount of Air Quality Development Authority Variable Rate Bonds due 2040.

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.

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