

Delmarva Power
PO Box 9239
Newark, DE 19714-9239
800.375.7117

delmarva.com

-225520

May 31, 2019

David J. Collins, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower, 16th Floor
6 St. Paul Street
Baltimore, Maryland 21202-6806

FILED
MAY 30 2019
PUBLIC SERVICE COMM
OF MARYLAND

Dear Mr. Collins:


Submitted herewith is Delmarva Power & Light Company's ("DPL") Annual Report to the Public Service Commission of Maryland for the year ended December 31, 2018 as compiled on FERC Form No. 1 pursuant to the Commission's instructions.

We respectfully submit the following reports:

- One (1) copy of the 2018 DPL Form 1, Annual Report which is the same report as filed with Federal Energy Regulatory Commission (FERC).
- One (1) copy of the Addendum to 2018 Annual Report/Maryland Jurisdictional Electric Sales Statistics.
- One (1) copy of the report of Energy Taxes and Property Taxes paid in 2018 to each municipal, county and state agency in Maryland.
- One (1) copy of the Exelon First Quarter 2019 Form 10-Q (the most current corporate shareholder report).
- One (1) CD-ROM with a PDF version of the FERC Form No. 1 for the year ended December 31, 2018.
- Affidavit on cost allocations and transfer pricing of assets.

If you have any questions, please feel free to contact me at (779) 231-1264.

Sincerely,



Kevin Reeve, CPA

Manager, External Financial Reporting, Exelon
10 S. Dearborn, Chicago, IL 60603
Kevin.Reeve@exeloncorp.com

Enclosures

RECEIVED
Public Service Commission

MAY 30 2019

ACCOUNTING INVESTIGATIONS
DIVISION

Delmarva Power
PO Box 9239
Newark, DE 19714-9239
800.375.7117

delmarva.com

May 31, 2019

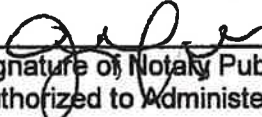
To: David J. Collins, Executive Secretary
Maryland Public Service Commission

In accordance with section 6-205 of the Public Utilities Article, Annotated Code of Maryland, attached is the signed copy of the Delmarva Power and Light 2018 FERC Form 1 report.




Signature of Officer
Of Reporting Utility

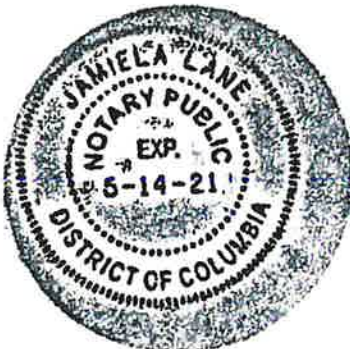
Subscribed and Sworn to Before Me This
29 Day MAY 2019



Signature of Notary Public
Authorized to Administer

District of Columbia: SS
Subscribed and sworn to before me, in my presence,
this 29 day of May 2019



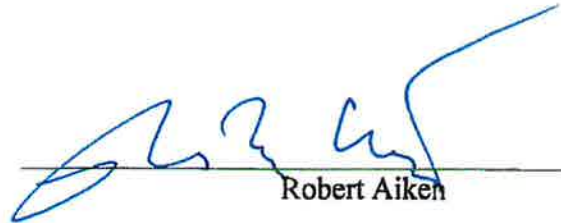
Jameila Lane, Notary Public, D.C.
My commission expires May 14, 2021.

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND**

**AFFIDAVIT OF
ROBERT AIKEN**

Robert Aiken, being duly sworn, states the following:


I, Robert Aiken, am the Vice President and Controller of Pepco Holdings LLC, a public utility holding company for Delmarva Power & Light Company (Delmarva) and Potomac Electric Power Company (Pepco). I hereby certify that the cost allocation contained in the Pepco Holdings LLC Cost Allocation Manual (CAM) and the transfer pricing of assets comply with the Commission's Affiliate Regulations contained in COMAR Subtitle 20.40.



Robert Aiken

City of Wilmington)
State of Delaware)

Subscribed and sworn to me this 31st day of May, 2019 in the City of Wilmington, Delaware.


Notary Public



My Commission expires 08/05/19

DELMARVA POWER & LIGHT COMPANY
MARYLAND PROPERTY TAXES PAID
12/31/2018

<u>Location</u>	<u>2018 Taxes Paid</u>
Caroline County	782,572
Cecil County	3,344,785
City of Cambridge	160,472
City of Crisfield	39,771
City of Fruitland	84,015
City of Salisbury	1,050,841
Delmar	48,743
Dorchester County	2,380,154
Eldorado	149
Galena	2,127
Harford County	400,354
Hebron	5,271
Hillsboro	-
Hurlock	19,117
Kent County	1,418
Mardela Springs	4,955
Pocomoke City	103,032
Preston	3,171
Queen Anne's County	1,392,965
Ridgely	12,168
Secretary	2,269
Sharptown	7,403
Snow Hill	34,899
Somerset County	682,211
St. Michaels	28,841
Sudlersville	1,143
Talbot County	493,671
Town of Betterton	2,528
Town of Brookview	-
Town of Cecilton	2,118
Town of Centreville	106,984
Town of Charlestown	5,690
Town of Chesapeake City	8,514
Town of Chestertown	31,013
Town of Church Creek	229
Town of Church Hill	-
Town of Denton	42,409
Town of Elkton	252,852
Town of Federalsburg	24,024
Town of Goldsboro	-
Town of Greensboro	9,400
Town of Henderson	527
Town of Millington	-
Town of North East	43,317
Town of Ocean City	543,573
Town of Perryville	14,261
Town of Pittsville	7,960
Town of Port Deposit	12,650
Town of Princess Anne	56,075
Town of Queenstown	2,277
Town of Rising Sun	11,487
Town of Templeville	-
Town of Trappe	4,387
Town of Vienna	5,092
Town of Willards	18,301
Wicomico County	2,312,769
Worcester County	1,753,763
MD Other Property	300
Total	16,359,015

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted
- for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES *	
		Amount for Year (b)	Amount for Previous Year (c)
1	SALES OF ELECTRICITY		
2	(440) Residential Sales	290,683,123	270,546,292
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)	108,682,399	110,558,225
5	Large (or Industrial)	10,007,781	9,855,471
6	(444) Public Street and Highway Lighting	4,276,799	4,271,628
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways	-	-
9	(448) Interdepartmental Sales	-	-
10	TOTAL Sales to Ultimate Consumers	413,650,102	395,231,616
11	(447) Sales for Resale	-	-
12	TOTAL Sales of Electricity	413,650,102	395,231,616
13	(Less) (449.1) Provision for Rate Refunds	-	-
14	TOTAL Revenue Net of Provision for Refunds	413,650,102	395,231,616
15	OTHER OPERATING REVENUES		
16	(450) Forfeited Discounts	1,197,564	1,213,382
17	(451) Miscellaneous Service Revenues	194,905	598,905
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,780,392	1,580,484
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,887,059	14,044,880
22	(456.1) Revenues from Transmission of Electricity of Oth	605,907	689,356
23			
24			
25			
26	TOTAL Other Operating Revenues	11,665,827	18,127,007
27	TOTAL Electric Operating Revenues	425,315,929	413,358,623

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

- 4. Commercial & Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 kw of demand. (See Account 442. Explain basis of classification in a footnote.)
- 5. See page 108, Important Changes During the Year, for important new territory added and important rate increases or decreases.
- 6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
- 7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD **		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
w/p 300-1 Amount for Year (d)	Amount for Previous Year (e)	w/p 300-1 Number for Year (f)	Number for Previous Year (g)	Line No.
				1
2,219,317	2,042,853	178,170	177,696	2
				3
1,675,311	1,660,032	26,845	26,698	4
374,418	372,395	184	188	5
11,747	12,015	268	272	6
				7
				8
				9
4,280,793	4,087,295	205,467	204,854	10
-	-	-	-	11
4,280,793	4,087,295	205,467	204,854	12
-	-	-	-	13
4,280,793	4,087,295	205,467	204,854	14

* Includes (\$4,138,296) of unbilled revenues in 2018
 ** Includes (37,429) MWH relating to unbilled revenues in 2018

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

Amounts over \$250,000:		
RPM Auction	\$	6,058,294
MD Billed Stabilization		(4,333,343)
MD Calendar Revenue Normalization		2,522,773
MD Intercompany Revenue		(1,763,501)

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

Amounts over \$250,000:		
MD Billed Stabilization Adjustment	\$	14,295,037
MD Billed Stabilization Adjustment Unbilled		(5,349,322)

\$4,447,939 of RPM Auction revenue has also been reclassified from Line 11, Column c to Line 21, Column c to conform to the current period presentation.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2019

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
101-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

THIS FILING IS

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

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



FERC FINANCIAL REPORT

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

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

Exact Legal Name of Respondent (Company)

Delmarva Power & Light Company

Year/Period of Report

End of 2018/Q4

DELMARVA POWER & LIGHT COMPANY
MARYLAND PROPERTY TAXES PAID
12/31/2018

<u>Location</u>	<u>2018 Taxes Paid</u>
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- | | |
|---|--|
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|---|--|

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THIS FILING IS

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

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



FERC FINANCIAL REPORT

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

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

Exact Legal Name of Respondent (Company)

Delmarva Power & Light Company

Year/Period of Report

End of 2018/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

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

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Delmarva Power & Light Company		02 Year/Period of Report End of <u>2018/Q4</u>	
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /			
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 500 North Wakefield Drive, Newark, Delaware 19702			
05 Name of Contact Person Robert Aiken		06 Title of Contact Person Vice President & Controller	
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> 630 Martin Luther King Blvd, Wilmington, Delaware 19801			
08 Telephone of Contact Person, <i>Including Area Code</i> (302) 429-3359	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report <i>(Mo, Da, Yr)</i> 04/02/2019

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 Phillip S. Barnett	03 Signature Phillip S. Barnett	04 Date Signed <i>(Mo, Da, Yr)</i> 04/02/2019
02 Title SVP, CFO & Treasurer		

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

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	N/A
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	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
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	N/A
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	N/A
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	N/A
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	N/A

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	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input type="checkbox"/> Two copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report End of <u>2018/Q4</u>
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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.

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
701 Ninth Street, N.W.
Washington, DC 20068

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.

Incorporated under the laws of the State of Delaware, April 22, 1909 and the Commonwealth of Virginia, December 31, 1979.

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.

Sale of electricity within the States of Delaware and Maryland
Sale of natural gas within the State of Delaware.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) Yes...Enter the date when such independent accountant was initially engaged:
(2) No

Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report End of <u>2018/Q4</u>
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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

At December 31, 2018, Delmarva Power & Light Company is controlled by Pepco Holdings LLC. Pepco Holdings LLC is controlled by PH Holdco LLC which is a special purpose subsidiary of Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon Corporation. For additional information, see the Exelon Corporation Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2018.

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Velazquez, David M.	591,425
2	Sr. Vice President and Chief Operating Officer	Anthony, J. Tyler	400,000
3	Sr. Vice President, Chief Financial Officer & Treasurer	Kinzel, Donna J.	333,684
4	Sr. Vice President, Chief Financial Officer & Treasurer	Barnett, Phillip S.	384,566
5	Sr. Vice President, Governmental & External Affairs	Lavinson, Melissa	375,000
6	Sr. Vice President, Legal and Regulatory Strategy	Bonney, Paul	402,046
7	Vice President and General Counsel	Stark, Wendy E.	303,016
8	Sr. Vice President, Legal and Regulatory Strategy	Stark, Wendy E.	325,000
9	and General Counsel		
10	Vice President, Regulatory Policy and Strategy	McGowan, Kevin M.	330,000
11	Vice President and Controller	Aiken, Robert M.	302,575
12	Corporate Secretary	Wilson, Bruce G.	426,348
13	Corporate Secretary	O'Neill, Thomas	525,000
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18	Listed officers are employees of PHI Service Company		
19	or Exelon Business Services Company LLC; salary for		
20	year represents the executive's annual base salary		
21	as of December 31, 2018 and only a portion of their		
22	annual base salary is allocated to DPL.		
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Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 3 Column: b

Effective July 6, 2018, Donna J. Kinzel resigned from the role of Sr. Vice President, Chief Financial Officer and Treasurer.

Schedule Page: 104 Line No.: 4 Column: b

Effective September 1, 2018, Phillip S. Barnett was elected to the role of Sr. Vice President, Chief Financial Officer and Treasurer.

Schedule Page: 104 Line No.: 5 Column: b

Effective January 22, 2018, Melissa Lavinson was elected to the role of Sr. Vice President, Governmental & External Affairs.

Schedule Page: 104 Line No.: 6 Column: b

Effective December 31, 2018, Paul R. Bonney resigned from the role of Sr. Vice President, Legal and Regulatory Strategy.

Schedule Page: 104 Line No.: 7 Column: b

Effective November 26, 2018, Wendy E. Stark resigned from the role of Vice President and General Counsel.

Schedule Page: 104 Line No.: 8 Column: b

Effective November 26, 2018, Wendy E. Stark was elected to the role of Sr. Vice President, Legal and Regulatory Strategy and General Counsel.

Schedule Page: 104 Line No.: 12 Column: b

Effective January 2, 2018, Bruce Wilson resigned from the role of Corporate Secretary.

Schedule Page: 104 Line No.: 13 Column: b

Effective January 2, 2018, Thomas O'Neill was elected to the role of Corporate Secretary.

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	Pramaggiore, Anne R. ***	701 Ninth Street, N.W., Washington, D.C. 20068
2	Chairman and Director	
3		
4	Velazquez, David M.	701 Ninth Street, N.W., Washington, D.C. 20068
5	Director	
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Name of Respondent
Delmarva Power & Light Company

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

Date of Report
(Mo, Da, Yr)
04/02/2019

Year/Period of Report
End of 2018/Q4

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

Does the respondent have formula rates?

Yes
 No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Attachment H-3D of PJM OATT	ER05-515
2	Attachment H-3D of PJM OATT	ER08-10, incentive filing
3	Attachment H-3D of PJM OATT	ER08-686, incentive filing
4	Attachment H-3D of PJM OATT	ER08-1423, incentive filing
5	Attachment H-3D of PJM OATT	ER13-607, incentive filing
6	Attachment H-3D of PJM OATT	EL13-48, ROE
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Name of Respondent
Delmarva Power & Light Company

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

Date of Report
(Mo, Da, Yr)
04/02/2019

Year/Period of Report
End of 2018/Q4

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

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

Yes
 No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20180515-5340	05/15/2018	ER09-1158	Informational Filing of Annual Formula	
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INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/02/2019	Year/Period of Report End of <u>2018/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

IMPORTANT CHANGES DURING THE QUARTER/YEAR

This information is for changes in the year ended December 31, 2018.

Item 1	- None
Item 2	- None
Item 3-5	- None
Item 6	- Refer to Note 8, "Debt and Credit Agreements" of the accompanying "Notes to the Financial Statements" for a discussion of DPL's debt. The authorizations for the issuances of long-term debt are Delaware Public Service Commission order number 9155 and Maryland Public Service Commission order number 88606.
Item 7-8	- None
Item 9	- Refer to Note 14, "Commitments and Contingencies" of the accompanying "Notes to Financial Statements" for a discussion of DPL's legal proceedings
Item 10	- None
Item 11	- "Reserved"
Item 12	- "Not Applicable"
Item 13	- See changes below:
Item 14	- DPL participates in a cash management program. As of December 31, 2018, DPL's proprietary capital ratio is greater than 30 percent.

Response to Item 13 above:

<u>Name</u>	<u>Executive Officer Position</u>	<u>Action and Date</u>
Paul R. Bonney	SVP, Legal and Regulatory Strategy	RESIGN - 12/31/2018
Wendy E. Stark	SVP, Legal and Regulatory Strategy	ELECT - 11/26/2018
Wendy E. Stark	VP, Legal and Regulatory Strategy	RESIGN - 11/26/2018
Phillip Barnett	SVP, CFO and Treasurer	ELECT - 9/1/2018
Donna Kinzel	SVP, CFO and Treasurer	RESIGN – 7/6/2018
Bruce Wilson	Secretary	RESIGN – 1/2/2018
Thomas O'Neill	Secretary	ELECT – 1/2/2018
Melissa Lavinson	SVP, Governmental and External Affairs	ELECT - 1/22/2018

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	5,034,659,642	4,660,010,387
3	Construction Work in Progress (107)	200-201	151,444,729	204,513,499
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,186,104,371	4,864,523,886
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,381,187,619	1,302,300,908
6	Net Utility Plant (Enter Total of line 4 less 5)		3,804,916,752	3,562,222,978
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)		3,804,916,752	3,562,222,978
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		13,916,770	11,919,059
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,378,893	4,268,017
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)		653,829	756,373
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		10,191,706	8,407,415
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		8,641,814	2,441,172
36	Special Deposits (132-134)		1,100,574	562
37	Working Fund (135)		0	19,635
38	Temporary Cash Investments (136)		14,664,218	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		88,638,440	103,499,962
41	Other Accounts Receivable (143)		43,897,314	30,611,706
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		12,701,997	16,175,968
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		218,636	226,092
45	Fuel Stock (151)	227	0	0
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	37,490,617	35,564,437
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	8,103,320	7,949,742

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	0	0
55	Gas Stored Underground - Current (164.1)		7,392,902	6,661,499
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,193,666	668,081
57	Prepayments (165)		17,480,714	16,429,271
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		622	364
60	Rents Receivable (172)		1,031,368	2,697,321
61	Accrued Utility Revenues (173)		59,266,575	68,565,190
62	Miscellaneous Current and Accrued Assets (174)		2,356,328	500,000
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		278,775,111	259,659,066
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		12,653,169	11,575,745
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	196,654,254	219,262,453
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)		0	1,484
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	188,543,578	195,598,268
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)		6,506,178	7,674,093
82	Accumulated Deferred Income Taxes (190)	234	223,225,419	233,134,397
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		627,582,598	667,246,440
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,721,466,167	4,497,535,899

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 2 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item previously netted Capital Leases of \$223,934 with its associated Accumulated Amortization of \$223,934. Capital Lease Accumulated Amortization is now reported in FERC Account 111.

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

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$223,934 of Capital Lease Accumulated Amortization previously reported in FERC Account 101.

Schedule Page: 110 Line No.: 24 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$756,373 from Supplemental Executive Retirement Plans previously reported in FERC account 128.

Schedule Page: 110 Line No.: 41 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$8,849,496 related to Accounts Receivable balances associated with third party suppliers previously reported in FERC Account 142.

Schedule Page: 110 Line No.: 56 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$668,081 related to Liquefied Natural Gas Inventory balances previously reported in FERC account 164.1.

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	2,250	2,250
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		537,612,396	537,612,396
7	Other Paid-In Capital (208-211)	253	385,896,940	235,196,940
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	9,924,450	9,924,450
11	Retained Earnings (215, 215.1, 216)	118-119	593,221,255	569,500,728
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,177,779	-2,177,779
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		1,504,630,612	1,330,210,085
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,482,230,000	1,282,230,000
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	22,000,000	26,000,000
22	Unamortized Premium on Long-Term Debt (225)		3,103,748	3,557,618
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,438,567	1,495,709
24	Total Long-Term Debt (lines 18 through 23)		1,505,895,181	1,310,291,909
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,599,969	6,140,474
29	Accumulated Provision for Pensions and Benefits (228.3)		20,018,094	16,859,021
30	Accumulated Miscellaneous Operating Provisions (228.4)		670,027	721,282
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		10,752,867	9,290,286
35	Total Other Noncurrent Liabilities (lines 26 through 34)		39,040,957	33,011,063
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	215,973,783
38	Accounts Payable (232)		99,800,080	77,523,762
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		32,837,898	46,274,762
41	Customer Deposits (235)		35,476,721	35,118,563
42	Taxes Accrued (236)	262-263	3,976,020	4,114,709
43	Interest Accrued (237)		8,019,399	7,680,967
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		406,613	485,518
48	Miscellaneous Current and Accrued Liabilities (242)		41,071,627	33,542,100
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		221,588,358	420,714,164
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		9,692,270	8,040,247
57	Accumulated Deferred Investment Tax Credits (255)	266-267	2,350,600	2,744,836
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	21,337,755	22,538,734
60	Other Regulatory Liabilities (254)	278	568,072,353	536,853,899
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)		740,492,579	716,423,878
64	Accum. Deferred Income Taxes-Other (283)		108,365,502	116,707,084
65	Total Deferred Credits (lines 56 through 64)		1,450,311,059	1,403,308,678
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,721,466,167	4,497,535,899

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 112 Line No.: 28 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$6,140,474 related to workers compensation and bodily injury accruals previously reported in FERC Account 242.

Schedule Page: 112 Line No.: 29 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$16,859,021 related to Supplemental Executive Retirement Plans, Long-term Incentive Plans, Other Postemployment Benefits and deferred compensation plans of which \$15,679,634 was previously reported in FERC Account 242 and \$ 1,179,387 was previously reported in FERC Account 253.

Schedule Page: 112 Line No.: 30 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$721,282 related to accrued environmental long-term liabilities previously reported in FERC Account 253.

Schedule Page: 112 Line No.: 48 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$3,429,545 related to Supplemental Executive Retirement Plan previously reported in FERC Account 186. Line item includes \$36,000 related to short term Deferred Compensation previously reported in FERC Account 253.

Schedule Page: 112 Line No.: 59 Column: d

Account was affected by policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item includes \$609,186 related to Third Party Supplier Deposits previously reported in FERC Account 242. Line item includes \$7,785,085 related to deferred rent of \$7,785,085 previously reported in FERC Account 242.

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,346,724,607	1,299,694,707		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	823,572,993	779,650,390		
5	Maintenance Expenses (402)	320-323	69,450,351	71,596,333		
6	Depreciation Expense (403)	336-337	130,416,438	123,245,979		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	511,847	274,786		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,853,960	1,853,960		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		63,357,835	33,520,645		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	55,521,339	56,097,371		
15	Income Taxes - Federal (409.1)	262-263	-1,337,606	-23,779,952		
16	- Other (409.1)	262-263	-87,017	7,157		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	102,449,945	173,484,848		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	77,530,284	69,656,388		
19	Investment Tax Credit Adj. - Net (411.4)	266	-394,236	-456,116		
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)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,167,785,565	1,145,839,013		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		178,939,042	153,855,694		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
1,165,515,872	1,139,137,126	181,208,735	160,557,581			2
						3
692,993,035	675,667,918	130,579,958	103,982,472			4
61,944,361	66,749,554	7,505,990	4,846,779			5
119,169,871	109,716,796	11,246,567	13,529,183			6
						7
511,847	263,020		11,766			8
1,853,960	1,853,960					9
						10
						11
61,993,677	32,362,063	1,364,158	1,158,582			12
						13
46,067,973	47,202,844	9,453,366	8,894,527			14
-3,270,682	-21,996,156	1,933,076	-1,783,796			15
-78,315	6,170	-8,702	987			16
91,010,064	156,915,490	11,439,881	16,569,358			17
68,387,344	63,991,923	9,142,940	5,664,465			18
-351,337	-411,229	-42,899	-44,887			19
						20
						21
						22
						23
						24
1,003,457,110	1,004,338,507	164,328,455	141,500,506			25
162,058,762	134,798,619	16,880,280	19,057,075			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		178,939,042	153,855,694		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		4,735,364	4,871,669		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		7,035,299	3,708,128		
33	Revenues From Nonutility Operations (417)		48,064	146,489		
34	(Less) Expenses of Nonutility Operations (417.1)		110,957	565,301		
35	Nonoperating Rental Income (418)		-525,332	481,425		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		1,459,504	228,169		
38	Allowance for Other Funds Used During Construction (419.1)		2,439,758	7,099,834		
39	Miscellaneous Nonoperating Income (421)		2,588,487	2,071,674		
40	Gain on Disposition of Property (421.1)		736,996	7,355		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,336,585	10,633,186		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		512,511	1,247,065		
46	Life Insurance (426.2)			-255,865		
47	Penalties (426.3)		92,535	46,736		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		491,163	404,679		
49	Other Deductions (426.5)		4,828,572	-1,684,258		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,924,781	-241,643		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	673,145	651,914		
53	Income Taxes-Federal (409.2)	262-263	-1,149,577	-11,941,467		
54	Income Taxes-Other (409.2)	262-263		-2,999,034		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	683,217	6,545,373		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	804,864			
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)		-598,079	-7,743,214		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-990,117	18,618,043		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		54,701,053	50,403,662		
63	Amort. of Debt Disc. and Expense (428)		947,480	901,855		
64	Amortization of Loss on Reaquired Debt (428.1)		1,167,916	1,176,434		
65	(Less) Amort. of Premium on Debt-Credit (429)		453,870	440,066		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		-17,976	33,667		
68	Other Interest Expense (431)		3,812,175	1,581,718		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,378,380	2,795,598		
70	Net Interest Charges (Total of lines 62 thru 69)		57,778,398	50,861,672		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		120,170,527	121,612,065		
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)		120,170,527	121,612,065		

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		569,500,728	559,488,663
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		120,170,527	121,612,065
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				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31				
32	Common Stock (Dividends paid to Parent)		-96,450,000	(111,600,000)
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-96,450,000	(111,600,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		593,221,255	569,500,728
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		593,221,255	569,500,728
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,177,779	(2,177,779)
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)		-2,177,779	(2,177,779)

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)	120,170,527	121,612,065
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	130,416,438	123,245,979
5	Amortization of regulatory debits/credits and limited plant	63,869,682	33,795,431
6	Plant Acquisition Adjustment	1,853,960	1,853,960
7	Impairment losses on long-lived assets and regulatory assets	138,820	6,219,239
8	Deferred Income Taxes (Net)	24,659,194	104,154,594
9	Investment Tax Credit Adjustment (Net)	-394,236	-456,115
10	Net (Increase) Decrease in Receivables	21,973,318	-4,458,848
11	Net (Increase) Decrease in Inventory	-3,183,168	-4,140,463
12	Net (Increase) Decrease in Allowances Inventory	-153,578	2,583,232
13	Net Increase (Decrease) in Payables and Accrued Expenses	-4,822,216	-13,305,451
14	Net (Increase) Decrease in Other Regulatory Assets	-46,033,432	-37,882,005
15	Net Increase (Decrease) in Other Regulatory Liabilities	24,453,642	-2,777,748
16	(Less) Allowance for Other Funds Used During Construction	2,439,758	7,099,834
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other Working Capital	-1,031,808	-2,860,812
19	Other Operating Activities	22,088,092	109,661
20	Net Increase (Decrease) in Interest and Taxes Accrued	199,683	-318,379
21	Gain on Sale of Land	-631,874	-7,355
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	351,133,286	320,267,151
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-366,299,095	-435,596,955
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	-2,439,758	-7,099,834
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-363,859,337	-428,497,121
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Proceeds from Sales of Assets	655,013	8,674
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Restricted Cash	-1,100,012	299,613
54	Other Investing Activities	1,521,041	-81,327
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-362,783,295	-428,270,161
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	200,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		215,973,783
67	Other (provide details in footnote):		
68	Capital Contribution from Parent	150,700,000	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	350,700,000	215,973,783
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-4,000,000	-40,000,000
74	Preferred Stock		
75	Common Stock		
76	Cost of Issuances	-1,761,348	183,673
77			
78	Net Decrease in Short-Term Debt (c)	-215,973,783	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-96,450,000	-111,600,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	32,514,869	64,557,456
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	20,864,860	-43,445,554
87			
88	Cash and Cash Equivalents at Beginning of Period	2,441,172	45,886,726
89			
90	Cash and Cash Equivalents at End of period	23,306,032	2,441,172

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 18 Column: a

Other Working Capital:		
	<u>2018</u>	<u>2017</u>
Working Fund	\$ 19,635	\$ 20,880
Prepayments	(1,051,443)	(2,881,692)
	<u>\$ (1,031,808)</u>	<u>\$ (2,860,812)</u>

Schedule Page: 120 Line No.: 19 Column: a

Other Operating Activities:		
	<u>2018</u>	<u>2017</u>
Property Plant & Equipment write-offs	\$ 7,782,891	\$ (162,549)
Depreciation expensed through clearing	773,942	-
Non utility depreciation	110,461	126,236
Supplemental Executive Retirement Plan expense	101,566	148,800
Clearing Account	1,484	649,544
Miscellaneous Deferred Debits	(513,720)	(1,858,349)
Asset Retirement Obligations	(826,685)	281,103
Customer Advances	1,324,819	(766,317)
Other Deferred Credits	(1,200,979)	(1,789,942)
Prepaid Pension Expense	8,053,072	12,667,822
Derivative Instruments	-	(1,273,649)
Merger Commitments	5,283,796	(2,075,311)
Contribution in aide of construction gross-up	-	(2,004,105)
Property Plant & Equipment settlement	-	1,096,746
Unamortized Discount on Long-Term Debt	1,455,111	1,232,737
Increase (decrease) in Accumulated Provisions for Injuries and Damages	1,459,495	1,014,319
Increase (decrease) in Accumulated Provisions for Pension and Benefits	(1,665,906)	(7,322,371)
Increase (decrease) in Accumulated Miscellaneous Operating Provisions	(51,255)	144,947
Total Other Operating Activities	<u>\$ 22,088,092</u>	<u>\$ 109,661</u>

Schedule Page: 120 Line No.: 19 Column: c

This line item was affected by balance sheet policy alignment between Exelon Corporation and Delmarva Power & Light Company. Line item now includes (\$6,308,052) of changes related to Accumulated Provision accounts (228.2 and 228.3) that was previously reported on the line for "Net Increase (Decrease) in Payables and Accrued Expenses".

Schedule Page: 120 Line No.: 54 Column: a

Other Investing Activities:		
	<u>2018</u>	<u>2017</u>
Net Utility Plant	\$ 2,575,016	\$ 418,673
Re-capitalized facility related depreciation	1,215,480	-
Purchase of CD's greater than 90 days	(250,000)	(500,000)
Increase in Other Investments	979	-
Net Nonutility plant	(2,020,434)	-
Total Other Investing Activities	<u>\$ 1,521,041</u>	<u>\$ (81,327)</u>

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/02/2019	Year/Period of Report End of <u>2018/Q4</u>
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NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The notes presented herein were derived from the notes disclosed within the Annual Report of the Exelon Corporate (Exelon) on Form 10-K for the period ending December 31, 2018. The notes presented herein were modified to include information relevant to DPL. All amounts presented within the footnotes are rounded in millions unless otherwise noted.

1. Significant Accounting Policies

Description of Business

Delmarva Power & Light Company (DPL) is engaged in the purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.

Basis of Presentation

DPL is an indirect, wholly owned, subsidiary of Exelon Corporation (Exelon).

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Federal Energy Regulatory Commission (FERC) under various federal laws. The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts (USOA) and accounting releases, which differ from accounting principles generally accepted in the United States (GAAP). The principal differences from GAAP include the exclusions of current maturities of long-term debt from current liabilities, the exclusion of debt issuance costs from long-term debt, the exclusion of restricted cash within cash and cash equivalents in the Statement of Cash Flows, the requirement to report deferred tax assets and liabilities separately rather than as a single amount, the classification of accrued taxes as assets and liabilities rather than a single amount, the exclusion of FIN 48 liabilities related to temporary income tax differences, and the classification of certain other assets and liabilities as current instead of noncurrent.

The accompanying financial statements as of December 31, 2018 and 2017 are audited, and in the opinion of the management of DPL, include all adjustments that are considered necessary for a fair presentation of DPL's financial statements in accordance with the Uniform System of Accounts (USOA). All adjustments are of a normal and recurring nature. The December 31, 2017 Balance Sheets were derived from audited financial statements. These notes should be read in conjunction with the Notes to Financial Statements of DPL in the December 31, 2017 FERC Form No. 1 "Annual Report of Major Electric Utilities, Licensees and Others" (FERC Form No. 1).

Use of Estimates

The preparation of financial statements in conformity with USOA and GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for other asset retirement obligations (AROs), pension and other postretirement benefits, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Accounting for the Effects of Regulation

For its regulated electric and gas operations, DPL reflects the effects of cost-based rate regulation in its financial statements, which is required for entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. DPL accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the Maryland Public Service Commission (MDPSC) and the Delaware Public Service Commission (DPSC), under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Statement of Income consistent with the recovery or refund included in customer rates. DPL's regulatory assets and liabilities as of the balance sheet date are probable of being recovered or settled in future rates. If a separable portion of DPL's business was no longer able to meet the criteria discussed above, DPL would be required to eliminate from its consolidated financial statements the effects of regulation for that portion, which could have a material impact on its financial statements. See Note 2 - Regulatory Matters for additional information.

DPL treats the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues

Operating Revenues. DPL's operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of energy commodities and related products and services, utility revenues from alternative revenue programs (ARP), and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. DPL recognizes revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that the entities expect to be entitled to in exchange for those goods or services. DPL's primary sources of revenue include regulated electric and natural gas tariff sales, distribution and transmission services. At the end of each month, DPL accrues an estimate for the unbilled amount of energy delivered or services provided to customers.

DPL records ARP revenue for its best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that it believes are probable of approval by the MDPSC in accordance with its revenue decoupling mechanisms. DPL records ARP revenue for its best estimate of the transmission revenue impacts resulting from future changes in rates that it believes are probable of approval by FERC in accordance with its formula rate mechanisms. See Note 2 - Regulatory Matters and Note 15 - Supplemental Financial Information for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. DPL collects certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees, that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by DPL, while others are imposed on DPL. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Statement of Income. However, where these taxes are imposed on DPL, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 15 - Supplemental Financial Information for DPL's utility taxes that are presented on a gross basis.

Income Taxes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Deferred Federal and state income taxes are recorded on significant temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred in DPL's Balance Sheets and are recognized in book income over the life of the related property. DPL accounts for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. DPL recognizes accrued interest related to unrecognized tax benefits in Interest expense or Other income and deductions (interest income) and recognize penalties related to unrecognized tax benefits in Other, net in its Statement of Income.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 9 - Income Taxes for additional information.

Cash and Cash Equivalents

DPL considers investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2018, and 2017, DPL's restricted cash and cash equivalents primarily represented funds restricted for the collateral held from energy suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects DPL's best estimates of losses on the customers' accounts receivable balances. DPL estimates the allowance by applying loss rates developed specifically for DPL to the outstanding receivable balance by customer risk segment. DPL's customer accounts are written off consistent with approved regulatory requirements.

Inventories

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Materials and supplies are generally included in inventory when purchased. Materials and supplies generally includes transmission, distribution and generating plant materials and are expensed to operating and maintenance or capitalized to property, plant and equipment, as appropriate, when installed or used.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. DPL also includes indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes Allowance for Funds Used During Construction (AFUDC) for regulated property. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is

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charged to Operating and maintenance expense as incurred.

Third parties reimburse DPL for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant and equipment, net. DOE SGIG and other funds reimbursed to DPL have been accounted for as CIAC.

For DPL, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation consistent with the composite and group methods of depreciation. Depreciation expense at DPL includes the estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs.

Capitalized Software Costs. Certain costs, such as design, coding, and testing incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within Property, plant and equipment. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements.

AFUDC. AFUDC is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to an allowance that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

See Note 4 - Property, Plant and Equipment and Note 15 - Supplemental Financial Information for additional information regarding property, plant and equipment.

Depreciation and Amortization

Depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. DPL's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with its regulatory recovery method. The estimated service lives for DPL are based on a combination of depreciation studies, historical retirements, site licenses and management estimates of operating costs and expected future energy market conditions.

See Note 4 - Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in DPL's Statement of Income. Amortization of DPL's transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in DPL's Statements of Income.

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See Note 2 - Regulatory Matters and Note 15 - Supplemental Financial Information for additional information regarding the amortization of DPL's regulatory assets.

Asset Retirement Obligations

AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Statement of Income or, in the case of DPL's accretion, through an increase to regulatory assets. See Note 10 - Asset Retirement Obligations for additional information.

Guarantees

DPL recognizes, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as DPL is released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of DPL may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 14 - Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. DPL evaluates the carrying value of its long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. DPL determines if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the net assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value.

Derivative Financial Instruments

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Changes in fair value may be recorded as a regulatory asset or liability if there is an ability to recover or return the associated costs. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statement of Cash Flows, depending on the nature of each transaction.

Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on

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derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 7 - Derivative Financial Instruments for further information.

Retirement Benefits

DPL participates in Exelon's defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, assumptions, and accounting elections. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the Statement of Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 11 - Retirement Benefits for additional information.

New Accounting Pronouncements

New Accounting Standards Adopted in 2018

In 2018, DPL adopted the following new authoritative accounting guidance issued by the FASB.

Defined Benefit Plan Disclosures (Issued August 2018). Eliminates existing disclosure requirements related to amounts in Accumulated other comprehensive income expected to be recognized in Net periodic benefit cost over the next year and the effects of a one-percentage-point change in the assumed health care cost trend rates. In addition, new disclosures were added such as the weighted-average interest crediting rates for cash balance plans and an explanation for the reasons for significant gains and losses related to changes in the benefit obligation. The standard is effective January 1, 2021, with early adoption permitted, and must be applied retrospectively. Exelon early adopted this standard in the fourth quarter of 2018.

Fair Value Measurement Disclosures (Issued August 2018). Updates the disclosure requirements for fair value measurements to improve the usefulness of information for financial statement users. The guidance removes the requirements to disclose (1) the amount of and reasons for transfers between Level 1 and Level 2, (2) the policy for timing of transfers between levels, and (3) the valuation processes for Level 3 fair value measurements and adds a requirement to disclose the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. The standard is effective January 1, 2020, with early adoption permitted. The amendments to remove disclosures must be applied retrospectively and can be early adopted, while the amendments to add disclosures must be applied prospectively and adoption can be delayed until the effective date. DPL early adopted, in the fourth quarter of 2018, the amendments to remove disclosures and will adopt the amendments to add disclosures in the first quarter of 2020. The impact of the new disclosures is not expected to be material to DPL's financial statements. See 6 - Fair Value of Financial Assets and Liabilities for additional information.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Issued March 2017). Changes the accounting and presentation of pension and OPEB costs at the plan sponsor (i.e., Exelon) level. The guidance requires plan sponsors to report the service cost and other non-service cost components of net periodic pension cost and net periodic OPEB cost (together, net benefit cost) separately. Under the new guidance, service cost is presented as part of income from operations and the other non-service cost components are classified outside of income from operations in the Statement of Income. Additionally, service cost is the only component eligible for capitalization on a prospective basis beginning on January 1, 2018. Under prior GAAP, the total

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amount of net benefit cost was recorded as part of income from operations and all components were eligible for capitalization.

DPL participates in Exelon's single employer pension and OPEB plans and apply multi-employer accounting. Multi-employer accounting was not impacted by this standard; therefore, Exelon's subsidiary financial statements did not change upon its adoption.

Statement of Cash Flows: Classification of Restricted Cash (Issued November 2016). The standard states that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows (instead of being presented as cash flow activities). The guidance was not adopted for FERC reporting purposes and results in no change to the Statement of Cash Flows.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016). Eliminates the available-for-sale and cost method classification for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings and, for equity investments without a readily determinable fair value, provides a measurement alternative of cost less impairment plus or minus adjustments for observable price changes in identical or similar assets. In addition, equity investments without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If fair value is less than carrying value, the impairment is recorded through net income immediately in the period in which it is identified. The guidance does not impact the classification or measurement of investments in debt securities. The guidance also amends several disclosure requirements, including requiring i) financial assets and financial liabilities to be presented separately in the balance sheet or note, grouped by measurement category and form, ii) disclosure of the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and iii) for financial assets and liabilities measured at amortized cost, disclosure of the fair value of the amount that would be received to sell the asset or paid to transfer the liability. The guidance was applied using a modified retrospective transition approach with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption. DPL recorded an insignificant adjustment to opening retained earnings as of January 1, 2018 related to unrealized gains/losses on available for sale equity securities.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions). Changes the criteria for recognizing revenue from a contract with a customer. The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five-step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The guidance was not adopted for FERC reporting purposes and results in no change to the Statement of Income.

New Accounting Standards Adopted as of January 1, 2019

The following new authoritative accounting guidance issued by the FASB was adopted as of January 1, 2019 and will be reflected by DPL in its consolidated financial statements beginning in the first quarter of 2019.

Cloud Computing Arrangements (Issued August 2018). Aligns the requirements for capitalizing costs incurred to implement a cloud computing arrangement with the internal-use software guidance. As a result, certain implementation costs incurred in a cloud computing arrangement that are currently expensed as incurred will be deferred and amortized over the non-cancellable term of the

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arrangement plus any reasonably certain renewal periods. The standard is effective January 1, 2020, with early adoption permitted, and can be applied using either a prospective or retrospective transition approach. A retrospective approach requires a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. DPL early adopted this standard using a prospective approach as of January 1, 2019. The new guidance is not expected to have a material impact on DPL's financial statements.

Leases (Issued February 2016). Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. DPL adopted the standard on January 1, 2019.

The new standard requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas under previous GAAP only finance lease liabilities (referred to as capital leases) were recognized in the balance sheet. In addition, the definition of a lease has been revised which may result in changes to the classification of an arrangement as a lease. Under the new standard, an arrangement that conveys the right to control the use of an identified asset by obtaining substantially all of its economic benefits and directing how it is used is a lease, whereas the previous definition focuses on the ability to control the use of the asset or to obtain its output. Quantitative and qualitative disclosures related to the amount, timing and judgments of an entity's accounting for leases and the related cash flows are expanded. Disclosure requirements apply to both lessees and lessors, whereas previous disclosures related only to lessees. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous GAAP. Lessor accounting is also largely unchanged. The guidance was not adopted for FERC reporting purposes and will result in no change to the Balance Sheet in 2019.

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2018

The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by DPL in its financial statements as of December 31, 2018. Unless otherwise indicated, DPL is currently assessing the impacts such guidance may have (which could be material) in its Balance Sheet, Statement of Income, Statement of Cash Flows and disclosures, as well as the potential to early adopt where applicable. DPL has assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact DPL's financial reporting.

Goodwill Impairment (Issued January 2017). Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. DPL does not have goodwill as of December 31, 2018. This updated guidance is not currently expected to impact DPL's financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.

Impairment of Financial Instruments (Issued June 2016). Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity's current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. DPL is currently assessing the impacts of this standard.

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2. Regulatory Matters

The following matters below discuss the status of material regulatory and legislative proceedings of DPL.

Utility Regulatory Matters

Distribution Base Rate Case Proceedings

The following table shows the completed distribution base rate case proceedings in 2018.

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase (Decrease)	Approved Revenue Requirement Increase (Decrease)	Approved ROE	Approval Date	Rate Effective Date
DPL - Maryland (Electric)(a)	July 14, 2017 (amended November 16, 2017)	\$ 19 (a)	\$ 13	9.5%	February 9, 2018	February 9, 2018
DPL - Delaware (Electric)	August 17, 2017 (amended February 9, 2018)	\$ 12	\$ (7) (b)	9.7%	August 21, 2018	March 17, 2018
DPL - Delaware (Natural Gas)	August 17, 2017 (amended February 9, 2018)	\$ 4	\$ (4) (b)	9.7%	November 8, 2018	March 17, 2018

(a) The DPL Maryland base rate case proceeding was resolved through a settlement agreement, which did not specify an overall ROE. The settlement agreement included an ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset carrying costs. In the second quarter of 2018, DPL discovered a rate design issue in Maryland such that the current rates were not sufficient to collect the full amount of the \$13 million revenue increase agreed to by the parties in the recent settlement. On September 5, 2018, the MDPSC approved DPL's proposed revisions to resolve the rate design issue on a prospective basis, effective September 5, 2018.

(b) Includes the annual ongoing TCJA tax savings further discussed below.

Transmission Formula Rates

Transmission Formula Rate. DPL's transmission rate is established based on a FERC-approved formula. DPL is required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rate effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year (annual reconciliation).

For 2018, the following total increases were included in DPL's electric transmission formula rate filing:

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Registrant	Initial Revenue Requirement (Decrease) Increase ^(a)	Annual Reconciliation Increase/(Decrease)	Total Revenue Requirement (Decrease) Increase	Allowed Return on Rate Base ^(b)	Allowed ROE ^(c)
DPL	\$ 14	\$ 13	\$ 27	7.29%	10.50%

- (a) The initial revenue requirement change reflects the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of \$12 million for DPL. It does not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion below.
- (b) Represents the weighted average debt and equity return on transmission rate bases.
- (c) As part of the FERC-approved settlement of the ROE complaint against DPL, the rate of return on common equity is 10.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO.

Tax Cuts and Jobs Act

DPL has made filings with its state regulatory commissions to pass back tax savings related to TCJA to its distribution customers, which are detailed below. The tax savings include the benefit of lower federal income tax rates and the settlement of a portion of the deferred income tax regulatory liabilities established upon the enactment of the TCJA. The ongoing annual TCJA tax savings in the table below represent the annual savings for distribution customers reflected in the initial customers rates approved after the TCJA. Subsequent annual TCJA tax savings will be approved as part of the annual update to the electric distribution formula rate for DPL.

Registrant/Jurisdiction	Amount	Ongoing TCJA Tax Savings		Stub Period Bill Credit from TCJA Tax Savings		
		Approval Date	Rate Effective Date	Stub Period	Approval Date	Refund Amount/Period
DPL - Maryland (Electric)	\$ 14	April 18, 2018	April 20, 2018	January 1, 2018 - March 31, 2018	April 18, 2018	\$2 / June 2018
DPL - Delaware (Electric)	\$ 19	August 21, 2018	March 17, 2018	February 1, 2018 - March 17, 2018	August 21, 2018	\$3 / Q4 2018
DPL - Delaware (Natural Gas)	\$ 7	November 8, 2018	March 17, 2018	February 1, 2018 - March 17, 2018	November 8, 2018	\$1 / Q4 2018

As discussed above, DPL's transmission formula rate currently does not provide for the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. On December 13, 2016 (as amended on March 13, 2017) and on February 23, 2018 (as amended on July 9, 2018), DPL filed with FERC to revise its transmission formula rate mechanisms to provide for pass back and recovery of transmission-related income tax-related regulatory liabilities and assets, including those established upon enactment of the TCJA. See discussion below for additional information regarding these filings.

See Note 9 - Income Taxes for additional information on Corporate Tax Reform.

Other Federal Regulatory Matters

Transmission-Related Income Tax Regulatory Assets. On December 13, 2016 (as amended on March 13, 2017), Baltimore Gas and Electric Company (BGE) filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. DPL had similar transmission-related income tax regulatory liabilities and assets also requiring FERC approval. On

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November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. FERC's rejection order focused on the lack of timeliness of BGE's request to recover amounts that would have been previously amortized but indicated that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement. Based on FERC's order, management of each company concluded that the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery was no longer probable of recovery. As a result, DPL recorded \$6 million in charges to Income tax expense within its Statement of Income in the fourth quarter of 2017, reducing its associated transmission-related income tax regulatory assets.

On December 18, 2017, BGE filed for clarification and rehearing of FERC's order, still seeking full recovery of its existing transmission-related income tax regulatory asset amounts, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. On February 27, 2018 (and updated on March 26, 2018), BGE submitted a letter to FERC advising that the lower federal corporate income tax rate effective January 1, 2018 provided for in the TCJA will be reflected in BGE's annual formula rate update effective June 1, 2018, but that the deferred income tax benefits will not be passed back to customers unless BGE's formula rate is revised to provide for pass back and recovery of transmission-related income tax-related regulatory liabilities and assets.

On February 23, 2018 (as amended on July 9, 2018), DPL filed with FERC to revise its transmission formula rate mechanisms to facilitate passing back to customers ongoing annual TCJA tax savings and to permit recovery of transmission-related income tax regulatory assets, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery.

On September 7, 2018, FERC issued orders rejecting BGE's December 18, 2017 request for rehearing and clarification and DPL's February 23, 2018 (as amended on July 9, 2018) filings, again citing the lack of timeliness of the requests to recover amounts that would have been previously amortized, but indicating that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement. The orders did not address the remittance of TCJA transmission-related income tax regulatory liabilities, but rather referenced FERC's separate Notice of Inquiry of such amounts issued on March 15, 2018.

On October 1, 2018, DPL submitted a new filing to recover ongoing non-TCJA amortization amounts and refund TCJA transmission-related income tax regulatory liabilities for the prospective period starting on October 1, 2018. FERC issued a deficiency letter requesting additional information on November 21, 2018 and January 28, 2019. DPL responded to the November 21, 2018 deficiency letter on November 29, 2018 but cannot predict the outcome of these FERC proceedings. If FERC ultimately rules that the future, ongoing non-TCJA amortization amounts are not recoverable, DPL would record additional charges to Income tax expense, which could be up to approximately \$5 million as of December 31, 2018.

On October 9, 2018, DPL sought a rehearing of FERC's September 7, 2018 order, still seeking full recovery of its existing transmission-related income tax regulatory asset amount, including the amount that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. DPL cannot predict the outcome of this rehearing request. On November 2, 2018, BGE filed an appeal of FERC's September 7, 2018 order to the Court of Appeals for the D.C. Circuit.

PJM Transmission Rate Design. On June 15, 2016, several parties, including DPL, filed a proposed settlement with FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. The settlement included provisions for monthly credits or charges related to the periods prior to January 1, 2016 that are expected to be refunded or recovered through PJM wholesale transmission rates through December 2025.

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On May 31, 2018, FERC issued an order approving the settlement and directed PJM to adjust wholesale transmission rates within 30 days. Pursuant to the order, similar charges for the period January 1, 2016 through June 30, 2018 will also be refunded or recovered through PJM wholesale transmission rates over the subsequent 12-month period. PJM commenced billing the refunds and charges associated with this settlement in August 2018. DPL expects to recover these settlement amounts through prospective electric distribution customer rates. On July 2, 2018, several parties filed petitions for rehearing or clarification.

Pursuant to the FERC approval of the settlement and the expected refund or recovery of the associated amounts from electric distribution customers, in the second quarter of 2018 and as adjusted in the third quarter of 2018, DPL recorded a receivable to PJM for \$10 million and a related regulatory liability for \$10 million.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of DPL as of December 31, 2018 and December 31, 2017:

Regulatory Assets (Account 182.3)	December 31, 2018	December 31, 2017
AMI programs - Deployment Costs	\$ 39	\$ 33 (a)
AMI programs - Legacy Meters	30	34 (a)
Electric Energy and Natural Gas Costs	7	11 (a)
Transmission formula rate annual reconciliations	14	8 (a)
Energy efficiency and demand response programs	73	105 (a)
Merger integration costs	11	6 (a)
Under-recovered electric revenue decoupling	—	3
Deferred storm costs	4	5
Other	19	14 (a)
Total regulatory assets	<u>\$ 197</u>	<u>\$ 219</u>
Regulatory Liabilities (Account 254)	December 31, 2018	December 31, 2017
Deferred income taxes	\$ 510	\$ 511
Electric Energy and Natural Gas Costs	25	26 (a)
Other	33	— (a)
Total regulatory liabilities	<u>\$ 568</u>	<u>\$ 537</u>

(a) The 2017 amounts include immaterial reclassifications between line items, which do not impact total regulatory assets and liabilities.

Descriptions of the regulatory assets and liabilities included in the tables above are summarized below, including their recovery and amortization periods.

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Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Deferred Income Taxes	Deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of AFUDC, and the effects of income tax rate changes, including those resulting from the TCJA. These amounts include transmission-related regulatory liabilities that require FERC approval separate from the transmission formula rate. See Transmission-Related Income Tax Regulatory Assets section above for additional information.	Over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
AMI Programs - Deployment Costs	Installation costs of new smart meters, including implementation costs of dynamic pricing for energy usage resulting from smart meters.	2030	Yes
AMI Programs - Legacy Meters	Early retirement costs of legacy meters.	2030	Delaware - Yes Maryland - No
Electric Energy and Natural Gas Costs	Under (over) recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	Delaware - Yes Maryland - No
Transmission formula rate annual reconciliations	Under (over)-recoveries related to transmission service costs recoverable through DPL's FERC formula rates, which are updated annually with rates effective each June 1st.	2020	Yes
Energy efficiency and demand response programs	Includes under (over)-recoveries of costs incurred related to energy efficiency programs and demand response programs and recoverable costs associated with customer direct load control and energy efficiency and conservation programs that are being recovered from customers.	2033	Yes
Merger Integration Costs	Integration costs to achieve distribution synergies related to the PHI acquisition.	2023	Yes
Under (Over)-Recovered Revenue Decoupling	Electric and / or gas distribution costs recoverable from or (refundable) to customers under decoupling mechanisms.	2019	No
Deferred Storm Costs	Amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland jurisdiction.	2023	Yes

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Capitalized Ratemaking Amounts Not Recognized

As of December 31, 2018 and 2017, DPL had \$3 million and \$4 million, respectively, of authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment on its AMI Program and Energy Efficiency and Demand Response Programs that were not recognized for financial reporting purposes on the Balance Sheets. The earnings on energy efficiency are on DPL Delaware programs only. These amounts will be recognized as revenues in the Statements of Operations and Comprehensive Income in the periods they are billable to customers.

3. Mergers, Acquisitions, and Dispositions

Merger with Exelon

Description of Transaction

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI), for a total purchase price consideration of approximately \$7.1 billion. As a result of the merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in Commonwealth Edison Company (ComEd), PECO Energy Company (PECO) and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI's unregulated business interests to Exelon and Exelon Generation Company, LLC (Generation) and the transfer of PHI, Potomac Electric Power Company (Pepco), DPL and Atlantic City Electric Company (ACE) to a special purpose subsidiary of EEDC.

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a "most favored nation" provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.

Total nominal cost of commitments was \$513 million excluding renewable generation commitments (approximately \$444 million on a net present value basis amount, excluding renewable generation commitments and charitable contributions).

The following amounts represent total commitment costs for DPL that have been recorded since the merger date:

Description	Expected Payment Period	DPL	
Rate Credits	2016 - 2021	\$	72
Charitable Contributions	2016 - 2026		12
Other			5
Total		\$	89

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Remaining commitments as of December 31, 2018 \$ 12

Pursuant to the orders approving the merger, Exelon made a \$46 million equity contribution to DPL in the second quarter of 2016 to fund the after-tax amounts of the customer bill credit and the customer base rate credit commitments.

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia and Delaware, at an estimated cost of approximately \$127 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be primarily capital in nature, will be recognized as incurred and recorded on Exelon's and Generation's financial statements. As of December 31, 2018, 27 MWs were developed and Exelon and Generation have incurred costs of \$83 million. Exelon has also committed to purchase 100 MWs of wind energy in PJM. DPL has committed to conducting three RFPs to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three wind REC RFPs. The first 40 MW wind REC tranche was conducted in 2017 and did not result in a purchase agreement. The second 40 MW wind REC tranche was conducted in 2018 and resulted in a proposed REC purchase agreement that is pending review and approval with the DPSC. The third and final 40 MW wind REC tranche will be conducted in 2022.

Pursuant to the various jurisdictions' merger approval conditions, over specified periods DPL is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and has made other commitments regarding hiring and relocation of positions.

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Maryland Court of Appeals, which is the highest court in Maryland. On August 29, 2018, the Maryland Court of Appeals affirmed the MDPSC's May 2015 Order approving the merger of Exelon and PHI.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District Legal Entity of Columbia Office of People's Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC's March 23, 2016 order with the District of Columbia Court of Appeals. On July 20, 2017, the Court issued an opinion rejecting all of appellants' arguments and affirming the Commission's decision approving the merger.

Accounting for the Merger Transaction

The total purchase price consideration for the PHI merger was approximately \$7.1 billion. The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled \$4 billion, which was recognized as goodwill by PHI and Exelon at the merger date, reflecting the value associated with enhancing Exelon's regulated utility portfolio of businesses, including the ability to leverage experience and best practices across the utilities and the opportunities for synergies. None of this goodwill is expected to be tax deductible. For purposes of future required impairment assessments, the goodwill has been assigned to PHI's reportable units Pepco, DPL and ACE.

Immediately following closing of the merger, \$235 million of net assets associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed \$163 million of such net assets to Generation.

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Rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. Historical cost information therefore is the most relevant presentation for the financial statements of DPL which is one of PHI's rate regulated utility subsidiary registrants. As such, Exelon and PHI did not push-down the application of acquisition accounting to PHI's utility registrants, and therefore the financial statements of DPL do not reflect the revaluation of any assets and liabilities.

For the periods ended December 31, 2018 and 2017, DPL has recognized costs to achieve the PHI merger as follows:

<u>Acquisition, Integration and Financing Costs(a)</u>	For the Year Ended December 31,	
	2018	2017(b)
DPL	\$ —	\$ (7)

- (a) The costs incurred are classified primarily within Operating and maintenance expense in DPL's Statements of Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.
- (b) For the year ended December 31, 2017, includes deferrals of previously incurred integration costs as regulatory assets of \$8 million at DPL.

4. Property, Plant and Equipment

The following table presents the average service life of property, plant and equipment by asset category as of December 31, 2018:

Asset Category	Average Service Life (years)
Electric - transmission and distribution	5-70
Gas - distribution	5-75
Common - electric and gas	5-75
Other property, plant and equipment(a)	10-43

- (a) Represents plant held for future use and non-utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2018	2017
Electric - transmission and distribution	2.77%	2.75%
Gas	1.59%	2.07%
Common-electric and gas	3.70%	4.14%

The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Capitalized Software Costs	2018	2017
Net unamortized software costs	21	1
Amortization of capitalized software costs	2	—

The following table summarizes total incurred interest and credits to AFUDC by year:

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Incurred Interest and credits to AFUDC	2018	2017
Total incurred interest (a)	62	54
Credits to AFUDC debt and equity	4	10

(a) Includes interest expense to affiliates.

DPL has undivided interests in jointly owned electric transmission facilities, which are financed with its funds and are accounted for as if such participating interests were wholly owned facilities. DPL's share of direct expenses of the jointly owned plants are included in Operating and maintenance expenses on DPL's Statement of Income. DPL's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2018 and 2017 were as follows:

Operator	First Energy	PSEG/DPL	Other
DPL's share at December 31, 2018			
	PA(a)	NJ/DE(b)	Other(c)
Plant(d)	2	2	2
Accumulated depreciation(d)	2	1	2
DPL's share at December 31, 2017			
	PA(a)	NJ/DE(b)	Other(c)
Plant(d)	2	2	2
Accumulated depreciation(d)	2	1	1

- (a) DPL owns a 9% share in 127 miles of 500 kV lines located in Pennsylvania as well as a 3.72% share of a 500 kV substation immediately outside of the Conemaugh fossil-generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.
- (b) DPL owns a 1% share in 151.3 miles of 500kV lines located in New Jersey and of the Salem generating plant substation. DPL also owns a 7.45% share in 2.5 miles of 500kV line located over the Delaware River.
- (c) DPL owns a 11.91% share in assets located at Merrill Creek Reservoir located in New Jersey. DPL owns a 7.4% share in Valley Forge Corporate Center.
- (d) Excludes asset retirement costs and general plant.

See Note 1 - Significant Accounting Policies for further information regarding property, plant and equipment policies.

5. Intangible Assets

Renewable Energy Credits

DPL's intangible assets, included in Allowances (Account 158.1) on its Balance Sheet, are Renewable Energy Credits (RECs). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are sold to a counterparty under a contract that specifically identifies a power plant is recognized at a point in time when the power is produced. This includes both bundled and unbundled REC sales. Otherwise, the revenue is recognized upon physical transfer of the REC to the customer. DPL had current RECs of \$8 million at both December 31, 2018 and 2017. DPL had no noncurrent RECs as of December 31, 2018 and 2017.

6. Fair Value of Financial Assets and Liabilities

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Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of DPL's short-term liabilities and long-term debt as of December 31, 2018 and 2017:

	December 31, 2018				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (Account 221, 224-226)	\$ 1,506	\$ —	\$ 1,303	\$ 193	\$ 1,496

	December 31, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities (Account 231)	\$ 216	\$ —	\$ 216	\$ —	\$ 216
Long-term debt (Account 221, 224-226)	1,310	—	1,393	—	1,393

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2). The carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of DPL's taxable debt securities (Level 2) and private placement taxable debt securities (Level 3) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate DPL's credit risk into the discount rates, DPL obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing DPL debt securities as well as debt securities of other issuers in the utility sector with similar credit ratings in both the primary and secondary market, across DPL's debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. Due to low trading volume of private placement debt, qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3.

DPL also has tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above. Variable rate tax-exempt debt (Level 2) resets on a regular basis and the carrying value approximates fair value.

Recurring Fair Value Measurements

DPL records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that DPL has the ability to

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liquidate as of the reporting date.

- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

The following tables present assets and liabilities measured and recorded at fair value on DPL's Balance Sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and 2017:

As of December 31, 2018

	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents (Account 132-134,136)(a)	\$ 16	\$ —	\$ —	\$ 16
Total assets	<u>16</u>	<u>—</u>	<u>—</u>	<u>16</u>
Liabilities				
Deferred compensation obligation (Account 253)	—	(1)	—	(1)
Total liabilities	<u>—</u>	<u>(1)</u>	<u>—</u>	<u>(1)</u>
Total net assets (liabilities)	<u>\$ 16</u>	<u>\$ (1)</u>	<u>\$ —</u>	<u>\$ 15</u>

As of December 31, 2017

	Level 1	Level 2	Level 3	Total
Liabilities				
Deferred compensation obligation (Account 253)	—	(1)	—	(1)
Mark-to-market derivative liabilities (Account 254)	(1)	—	—	(1)
Effect of netting and allocation of collateral (Account 254)	1	—	—	1
Mark-to-market derivative liabilities subtotal	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>
Total liabilities	<u>—</u>	<u>(1)</u>	<u>—</u>	<u>(1)</u>
Total net assets (liabilities)	<u>\$ —</u>	<u>\$ (1)</u>	<u>\$ —</u>	<u>\$ (1)</u>

(a) DPL excludes cash of \$8 million and \$2 million at December 31, 2018 and 2017, respectively.

DPL had no Level 3 assets or liabilities measured at fair value on a recurring basis during the years ended December 31, 2018 and 2017.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents. DPL's cash equivalents include investments with original maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

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Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that DPL believes provides the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. DPL's derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3. See Note 7—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations. DPL's deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. DPL includes such plans in other current and noncurrent liabilities in its Balance Sheet. The value of DPL's deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

7. Derivative Financial Instruments

DPL uses derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations.

Commodity Price Risk

DPL employs established policies and procedures to manage its risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, options and short-term and long-term commitments to purchase and sell energy and energy-related products. DPL believes these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge.

Fair value authoritative guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when

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collateral is requested or in the event of default.

As of December 31, 2018 and 2017, fair value balances associated with derivatives on DPL's Balance Sheet were immaterial.

Economic Hedges

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately \$2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for all of its SOS requirements through full requirements contracts. DPL's commodity price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up versus the forecast on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to 50% of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The 50% hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its Gas Hedging Program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

Interest Rate Risk

DPL uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. DPL also utilizes interest rate swaps, which are treated as economic hedges, to manage its interest rate exposure.

Credit Risk, Collateral and Contingent-Related Features

DPL would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date.

DPL's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is

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determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents DPL's net credit exposure. As of December 31, 2018, DPL's net credit exposure to suppliers was immaterial.

DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. DPL's counterparty credit risks are mitigated by its ability to recover realized energy costs through customer rates. See Note 2 — Regulatory Matters for additional information.

DPL's natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of December 31, 2018, DPL's credit exposure under its natural gas supply and asset management agreements was immaterial.

Collateral and Contingent-Related Features

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of December 31, 2018, DPL could have been required to post an additional amount of approximately \$11 million of collateral to its natural gas counterparties.

DPL's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require DPL to post collateral.

8. Debt and Credit Agreements

Short-Term Borrowings

DPL meets its short-term liquidity requirements primarily through the issuance of commercial paper. DPL may use its credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects DPL's commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2018 and December 31, 2017:

Commercial Paper Issuer	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2018(a)(b)	2017(a)(b)	2018	2017	2018	2017

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DPL	300	500	—	216	2.07%	1.48%
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- (a) At December 31, 2018, excludes credit facility agreements arranged at minority and community banks with aggregate commitments of \$5 million. These facilities expire on October 11, 2019. These facilities are solely utilized to issue letters of credit. At December 31, 2017, excludes credit facility agreements arranged at minority and community banks with aggregate commitments of \$2 million.
- (b) DPL's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by DPL may not exceed \$900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

In order to maintain its commercial paper programs in the amount indicated above, DPL must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under its credit facility, DPL does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

At December 31, 2018, DPL had the following aggregate bank commitments, credit facility borrowings and available capacity under its credit facility:

Borrower	Facility Type	Aggregate Bank Commitment ^(a)	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2018	
					Actual	To Support Additional Commercial Paper
DPL	Syndicated Revolver	300	—	1	299	299

- (a) Excludes additional credit facility agreements with aggregate commitments of \$5 million arranged with minority and community banks located primarily within DPL's service territories. These facilities expire on October 11, 2019. These facilities are solely utilized to issue letters of credit.

The following table presents the short-term borrowings activity for DPL during 2018 and 2017.

	2018	2017
Average borrowings	\$ 87	\$ 40
Maximum borrowings outstanding	245	216
Average interest rates, computed on a daily basis	2.07%	1.48%
Average interest rates, computed at December 31	2.07%	1.48%

Credit Agreements

On May 26, 2016, PHI and DPL entered into an amendment to its Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from \$1.5 billion to \$900 million and (iv) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio. On May 26, 2018, DPL's syndicated revolving credit facilities had their maturity dates extended to May 26, 2023.

Borrowings under DPL's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon DPL's credit rating. The adder for the prime based borrowings is 7.5 basis points and for the LIBOR-based borrowings is 107.5 basis points. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis

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points and 165 basis points, respectively. The credit agreements also require DPL to pay a facility fee based upon the aggregate commitments. The fee varies depending upon DPL's credit rating.

Each revolving credit agreement requires DPL to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The minimum credit agreement threshold reflected in the credit agreements for the year ended December 31, 2018 was 2.00 to 1. At December 31, 2018, the interest coverage ratio was 7.03.

An event of default under DPL's credit agreements would not constitute an event of default with respect to the other PHI Utilities under the PHI Utilities' combined credit facility.

The absence of a material change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under any of DPL's credit agreements. None of the credit agreements include any rating triggers.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. DPL expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the issuer and, as applicable, the credit support, and because the remarketing resets the interest rate to the then-current market rate. The bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, DPL views VRDBs as a source of long-term financing. As of both December 31, 2018 and December 31, 2017, \$79 million in VRDBs issued by DPL were outstanding and are included in the Long-term debt due within one year on its Balance Sheets.

Long-Term Debt

The following table presents DPL's outstanding long-term debt as of December 31, 2018 and 2017:

	Rates	Maturity Date	December 31,	
			2018	2017
Long-term debt				
First mortgage bonds (Account 221) ^(a)	1.81% - 4.27%	2023 - 2048	\$ 1,370	\$ 1,170
Unsecured Tax-Exempt Bonds (Account 221)	1.74% - 5.40%	2024 - 2031	112	112
Medium-Terms Notes (unsecured) (Account 224)	7.61% - 7.72%	2019 - 2027	22	26
Total long-term debt			1,504	1,308
Unamortized debt discount and premium, net (Accounts 225 and 226)			2	2
Unamortized debt issuance costs (Account 181)			(12)	(11)
Long-term debt due within one year			(91)	(83)
Long-term debt			\$ 1,403	\$ 1,216

(a) Substantially all of DPL's assets are subject to the lien of its respective mortgage indenture.

Issuance and Retirement of Long-Term Debt

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During the year ended December 31, 2018, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
First Mortgage Bonds	4.27%	June 15, 2048	\$ 200	Repay outstanding commercial paper and for general corporate purposes.

During the year ended December 31, 2017, no long-term debt was issued.

During the year ended December 31, 2018, the following long-term debt was retired:

Type	Interest Rate	Maturity	Amount
Medium Term Notes, Unsecured	6.81%	January 9, 2018	\$ 4

During the year ended December 31, 2017, the following long-term debt was retired:

Type	Interest Rate	Maturity	Amount
Medium Term Notes, Unsecured	7.56% - 7.58%	February 1, 2017	\$ 14
Variable Rate Demand Bonds	Variable	October 1, 2017	\$ 26

Long-term debt maturities at DPL in the periods 2019 through 2023 and thereafter are as follows:

Year	DPL
2019	\$ 91
2020	—
2021	—
2022	—
2023	500
Thereafter	913
Total	\$ 1,504

9. Income Taxes

Corporate Tax Reform

On December 22, 2017, President Trump signed the TCJA (Tax Cuts and Jobs Act) into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21%; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5) eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017. The most significant change that impacts DPL is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018.

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Pursuant to the enactment of the TCJA, DPL remeasured its existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to its net deferred income tax liability balances as shown in the table below. DPL recorded corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. The amount and timing of potential settlements of the established net regulatory liabilities will be determined by DPL's respective rate regulators, subject to certain IRS "normalization" rules. See Note 2 - Regulatory Matters for further information regarding settlements for passing back of TCJA income tax savings benefits to customers.

DPL assessed the applicable provisions in the TCJA and recorded the associated impacts as of December 31, 2017. DPL recorded provisional income tax amounts as of December 31, 2017, as allowed under SAB 118 issued by the SEC in December 2017, for changes pursuant to the TCJA related to depreciation because the impacts could not be finalized upon issuance of DPL's financial statements, but for which reasonable estimates could be determined.

On August 3, 2018, the U.S. Department of Treasury, in conjunction with the IRS, released proposed regulations clarifying the immediate expensing provisions enacted by the TCJA, specifically that regulated utility property acquired after September 27, 2017, and placed in service by December 31, 2017, qualifies for 100% expensing. Until the proposed regulations are finalized, taxpayers may rely on the proposed regulations for tax years ending after September 28, 2017. DPL recorded the impact of these proposed regulations and the adjustment was immaterial.

While DPL recorded the impacts of the TCJA based on its interpretation of the provisions as enacted, it is expected the U.S. Department of Treasury and IRS will issue additional interpretative guidance in the future that could result in changes to previously finalized provisions. At this time, many of the states in which Exelon does business have issued guidance regarding TCJA and the impact was not material.

The one-time impacts recorded by DPL to remeasure its deferred income tax balances at the 21% corporate federal income tax rate as of December 31, 2017 are presented below:

Net Decrease to Deferred Income Tax Liability Balances	\$	540
Net Regulatory Liability Recorded ^(a)		545
Net Deferred Income Tax Benefit/(Expense) Recorded	\$	<u>(5)</u>

(a) Reflects the net regulatory liabilities recorded on a pre-tax basis before taking into consideration the income tax benefits associated with the ultimate settlement with customers.

The net regulatory liabilities above include (1) amounts subject to IRS "normalization" rules that are required to be passed back to customers generally over the remaining useful life of the underlying assets giving rise to the associated deferred income taxes, and (2) amounts for which the timing of settlement with customers is subject to determinations by the rate regulators. The table below sets forth DPL's estimated categorization of its net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

Subject to IRS Normalization Rules	\$	195
Subject to Rate Regulator Determination		194
Net Regulatory Liabilities	\$	<u>389</u>

The net regulatory liability amounts subject to the IRS normalization rules generally relate to property, plant and equipment with

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remaining useful lives ranging from 30 to 40 years. For the other amounts, rate regulators could require the passing back of amounts to customers over shorter time frames. See Note 2 - Regulatory Matters for additional information.

The FERC accounts impacted by the remeasurement of deferred income taxes and the associated reversal of excess deferred taxes (i.e., excess deferred tax amortization) during the year ended December 31, 2018 are as follows:

FERC Account	Delaware Distribution Electric Amortization	Period of Amortization	Maryland Distribution Electric Amortization	Period of Amortization	Delaware Distribution Gas Amortization	Period of Amortization	Transmission Amortization	Period of Amortization	Other Amortization	Period of Amortization	Total
Protected											
282	\$ (1)	ARAM	\$ (1)	ARAM	\$ (1)	ARAM	\$ (1)	ARAM	N/A	ARAM	\$ (4)
Non-Protected											
190	—	5 years	—	10 years	—	5 years	—	10 years	N/A	5 years	—
282	(3)	6 years	(1)	39.7 years	(1)	6 years	(1)	34.8 years	N/A	5 years	(6)
283	(3)	5 years	(2)	10 years	(1)	5 years	—	10 years	(1)	5 years	(7)
Total Non-Protected	\$ (6)		\$ (3)		\$ (2)		\$ (1)		\$ (1)		\$ (13)
Total (Accounts 190, 282, 283)	\$ (7)		\$ (4)		\$ (3)		\$ (2)		\$ (1)		\$ (17)

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Year Ended December 31,	
	2018	2017(a)
Included in operations:		
Federal		
Current	\$ (3)	\$ (24)
Deferred	13	82
State		
Current	—	—
Deferred	12	13
Total (Accounts 409.1, 409.2, 410.1, 410.2, 411.1, 411.2, 411.4)	<u>\$ 22</u>	<u>\$ 71</u>

(a) DPL retrospectively adopted the new standard Revenue from Contracts with Customers. The standard was adopted as of January 1, 2018. Components of income tax expense or benefit are recast to reflect the impact of the new standard.

Rate Reconciliation

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The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Year Ended December 31,	
	2018	2017 ^(a)
U.S. Federal statutory rate	21.0%	35.0%
Increase (decrease) due to:		
State income taxes, net of Federal income tax benefit	6.7	5.4
Amortization of investment tax credit, including deferred taxes on basis difference	(0.3)	(0.2)
Plant Basis differences ^(b)	(0.3)	2.0
Merger Expenses	—	(7.8)
Excess deferred tax amortization	(12.0)	—
Tax Cuts and Jobs Act of 2017 ^(c)	—	2.5
Other	0.4	0.1
Effective income tax rate	15.5%	37.0%

- (a) DPL retrospectively adopted the new standard Revenue from Contracts with Customers. The standard was adopted as of January 1, 2018. The effective income tax rates are recast to reflect the impact of the new standard.
- (b) In 2017, includes the charges related to the transmission-related income tax regulatory asset for DPL of \$6 million. See Note 2 - Regulatory Matters for additional information.
- (c) Included are impacts of TJCA corporate rate change.

Tax Differences and Carryforwards

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2018 and 2017 are presented below:

	As of December 31,	
	2018	2017 ^(a)
Plant basis differences	\$ (743)	\$ (717)
Deferred pension and postretirement obligation	(46)	(51)
Deferred debt refinancing costs	(2)	(2)
Regulatory assets and liabilities	96	88
Tax loss carryforward	52	68
Other, net	17	14
Deferred income tax liabilities, net (Accounts 190, 282, 283)	\$ (626)	\$ (600)
Unamortized investment tax credits (Account 255)	(2)	(3)
Total deferred income tax liabilities (net) and unamortized investment tax credits	(628)	(603)

- (a) Includes remeasurement impacts related to the TCJA.

The following table provides DPL's carryforwards and any corresponding valuation allowances as of December 31, 2018. Note, there were no Federal carryforwards.

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State net operating losses and credit carryforwards ^(a)	772
Deferred taxes on state tax attributes (net)	52

(a) State net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2030.

Tabular reconciliation of unrecognized tax benefits

The following tables provide a reconciliation DPL's unrecognized tax benefits as of December 31, 2018 and 2017.

Unrecognized tax benefits at January 1, 2018	\$	21
Increases based on tax positions prior to 2018		1
Decreases based on tax positions prior to 2018		(22)
Unrecognized tax benefits at December 31, 2018	\$	<u>—</u>
Unrecognized tax benefits at January 1, 2017	\$	37
Increases based on tax positions prior to 2017		—
Decreases based on tax positions prior to 2017		(16)
Unrecognized tax benefits at December 31, 2017	\$	<u>21</u>

In the fourth quarter of 2018, DPL decreased its unrecognized state tax benefits by \$22 million due to the receipt of favorable guidance with respect to the deductibility of certain depreciable fixed assets. The recognition of the tax benefits related to DPL were offset by corresponding regulatory liabilities and that portion had no immediate impact to its effective tax rate.

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon's return, the IRS National Office issued guidance concurring with Exelon's position that the merger commitments were deductible. As a result, DPL decreased its liability for unrecognized tax benefits by \$16 million in the first quarter of 2017 resulting in a benefit to Income taxes on DPL's Statements of Income and corresponding decreases in its effective tax rate.

Unrecognized tax benefits that if recognized would affect the effective tax rate

DPL had \$0 million and \$21 million of unrecognized tax benefits as of December 31, 2018 and 2017 respectively, that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Unrecognized tax benefits that if recognized would affect only the timing of tax payments

DPL had no unrecognized tax benefits at both December 31, 2018 and 2017 that affected only the timing of tax payments.

Total amounts of interest and penalties recognized

DPL had no net interest and penalties receivable (payable), including interest and penalties related to tax positions reflected in its Balance Sheets at both December 31, 2018 and 2017.

DPL had no net interest and penalty expense, including interest and penalties related to tax positions, in its Statements of Income at

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both December 31, 2018 and 2017.

Description of tax years that remain open to assessment by major jurisdiction

<u>Taxpayer</u>	<u>Open Years</u>
Exelon (and predecessors) and subsidiaries consolidate federal income tax returns)	1999, 2001-2017
PHI Holdings and subsidiaries consolidated federal income tax returns	2013, 2015-2016
DPL Delaware separate company returns	Same as federal
Various separate company Maryland corporate net income tax returns	Same as federal

Other Tax Matters

State Income Tax Law Changes

On April 24, 2018, Maryland enacted companion bills, House Bill 1794 and Senate Bill 1090, providing for a phase in of a single sales factor apportionment formula from the current three factor formula for determining an entity's Maryland state income taxes. The single sales factor will be fully phased in by 2022.

In the second quarter of 2018, DPL recorded a one-time increase to deferred income taxes of approximately \$1 million. The increase to the Maryland deferred income tax liability was offset by regulatory assets. Further, the change in tax law is not expected to have a material ongoing impact to DPL's future results of operations.

Long-Term Marginal State Income Tax Rate

In the third quarter of 2018, Exelon reviewed and updated its marginal state income tax rates based on 2017 state apportionment rates. As a result of the rate changes, DPL recorded a one-time decrease to deferred income taxes of approximately \$2 million and a corresponding regulatory liability of approximately \$2 million.

Allocation of Tax Benefits

DPL is party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During both 2018 and 2017, DPL did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

10. Asset Retirement Obligations

DPL has AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and Polychlorinated Biphenyl ("PCBs"). See Note 1 — Significant Accounting Policies for additional information on the accounting policy for AROs.

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The following table provides a rollforward of the AROs reflected on DPL's Balance Sheets from January 1, 2017 to December 31, 2018:

Non-nuclear AROs at January 1, 2017	\$	9
Net increase due to changes in, and timing of, estimated future cash flows		1
Non-nuclear AROs at December 31, 2017 (Account 230)		10
Net increase due to changes in, and timing of, estimated future cash flows		1
Non-nuclear AROs at December 31, 2018 (Account 230)	\$	11

11. Retirement Benefits

Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all current employees.

The table below shows the pension and other postretirement benefit plans in which DPL employees participated at December 31, 2018.

Name of Plan:

Qualified Pension Plans:

- Exelon Corporation Cash Balance Pension Plan^(a)
- Pension Plan of Constellation Energy Group, Inc.^(b)
- Pepco Holdings LLC Retirement Plan^(c)

Non-Qualified Pension Plans:

- Conectiv Supplemental Executive Retirement Plan^(c)
- Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan^(c)

Other Postretirement Benefit Plans:

- PECO Energy Company Retiree Medical Plan^(a)
- Pepco Holdings LLC Welfare Plan for Retirees^(c)

(a) These plans are collectively referred to as the legacy Exelon plans.

(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.

(c) These plans are collectively referred to as the legacy PHI plans.

Contributions

The following table provide DPL's contributions to the pension and other postretirement benefit plans for the years ended December 31, 2018 and 2017:

	2018	2017
Pension Benefits	\$ —	\$ —
Other Postretirement Benefits	\$ —	\$ 2

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Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification).

The following table provides DPL's planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2019:

	Qualified Pension Plans	Non-Qualified Pension Plans	Other Postretirement Benefits
2019	\$ —	\$ 1	\$ —

Allocation to DPL

DPL accounts for its participation in Exelon's pension and other postretirement benefit plans by applying multi-employer accounting. Components of pension and other postretirement benefit costs and contributions have been, and will continue to be, allocated to DPL based on employee participation (both active and retired).

The amounts below represent DPL's allocated portion of the pension and postretirement benefit plan costs, which were included in Operating and maintenance expense within its Statements of Income and Property, plant and equipment within its Balance Sheets for the years ended December 31, 2018 and 2017.

	2018	2017
Pension and Other Postretirement Benefit Costs	\$ 6	\$ 13

Defined Contribution Savings Plan

DPL participates in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and after-tax income in accordance with specified guidelines. DPL matches a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the years ended December 31, 2018 and 2017.

	2018	2017
Savings Plan Matching Contributions	\$ 2	\$ 2

12. Severance

DPL has an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. DPL records a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), DPL measures the obligation and records the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

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Severance Costs Related to the PHI Merger

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. Cash payments under the plan began in May 2016 and will continue through 2020.

For the years ended December 31, 2018 and 2017, PHI Merger severance costs were immaterial.

DPL recorded regulatory assets for merger related integration costs which include a portion of the severance costs. The regulatory assets are either currently being recovered in rates or are deemed probable of recovery in future rates. See Note 2 - Regulatory Matters for additional information.

13. Shareholders' Equity

The following table presents common stock authorized and outstanding as of December 31, 2018 and 2017:

	Par Value	Shares Authorized	December 31,	
			2018	2017
			Shares Outstanding	
DPL	\$ 2.25	1,000	1,000	1,000

14. Commitments and Contingencies

Commercial Commitments

DPL's commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

	Total	Expiration within					2024 and beyond
		2019	2020	2021	2022	2023	
Surety bonds ^(a)	\$ 5	\$ 5	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	10	1	1	1	1	1	5
Total commercial commitments	\$ 15	\$ 6	\$ 1	\$ 1	\$ 1	\$ 1	\$ 5

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be \$26 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and DPL believes the likelihood of payments being required under the guarantees is remote.

Leases

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DPL's minimum future operating lease payments, including lease payments for vehicles, real estate, computers, operating equipment and office equipment, as of December 31, 2018 were:

2019	\$ 14
2020	13
2021	12
2022	12
2023	10
Remaining years	35
Total minimum future lease payments ^{(a)(b)}	\$ 96

(a) Includes amounts related to shared use land arrangements.

(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, DPL has excluded these payments from the remaining years as such amounts would not be meaningful. DPL's average annual obligation for these arrangements, included in each of the years 2019 - 2023, was \$1 million. Also includes amounts related to shared use land arrangements.

DPL's rental expense under operating leases was \$13 million and \$16 million for the years ended December 31, 2018 and 2017, respectively.

Environmental Remediation Matters

DPL's operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, DPL is generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. DPL owns or leases a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, DPL is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, DPL cannot reasonably estimate whether it will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by DPL, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the DPL's financial statements.

DPL has identified sites where former manufactured gas plant (MGP) or gas purification activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional potentially responsible parties that may share responsibility for the ultimate remediation of each location. DPL has identified 3 sites, 2 of which remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control. The remaining site is under study and the required cost at the site is not expected to be material.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

While DPL does not have riders for MGP clean-up costs, DPL has historically received recovery of actual clean-up costs in distribution

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
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NOTES TO FINANCIAL STATEMENTS (Continued)			

rates.

During the third quarter of 2018, DPL conducted a study of its future estimated environmental remediation requirements. The study did not result in a material change to the environmental liability for DPL.

As of both December 31, 2018 and 2017, DPL has accrued \$1 million in undiscounted amounts for environmental liabilities in Account 228.4, Accumulated Miscellaneous Operating Provisions on its Balance Sheets. The amounts related to MGP investigation and remediation were immaterial.

Litigation and Regulatory Matters

Fund Transfer Restrictions. Under applicable law, DPL can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at DPL may limit the dividends that the company can distribute to Exelon.

DPL is subject to certain dividend restrictions established by settlements approved in Delaware and Maryland. DPL is prohibited from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the DPSC and MDPSC or (b) DPL's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.

General. DPL is involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. DPL maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

15. Supplemental Financial Information

Supplemental Statement of Income Information

The following table provides additional information about DPL's Statements of Operations and Comprehensive Income for the years ended December 31, 2018 and 2017:

	For the Year Ended December 31,	
	2018	2017
Taxes other than income (Accounts 408.1 and 408.2)		
Utility(a)	\$ 21	\$ 18
Property	32	32
Payroll	3	4
Other	—	3
Total taxes other than income	<u>\$ 56</u>	<u>\$ 57</u>

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NOTES TO FINANCIAL STATEMENTS (Continued)			

- (a) DPL's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues in the DPL's Statements of Income.

Supplemental Statement of Cash Flows Information

Cash paid for interest (net of amount capitalized) was \$56 million and \$49 million for the years ended December 31, 2018 and 2017. Cash paid (refunded) for income taxes (net of refunds) was \$(6) million and \$(49) million for the years ended December 31, 2018 and 2017, respectively.

DPL's Statement of Cash Flows included non-cash investing activities relating to capital expenditures not paid increased by \$22 million and \$4 million for the years ended December 31, 2018 and 2017, respectively.

16. Related Party Transactions

The financial statements of DPL include related party transactions as presented in the tables below:

	Year Ended December 31,	
	2018	2017
Operating revenues from affiliates (Account 400)		
BSC	\$ 1	\$ —
PHISCO	4	6
ComEd	1	—
ACE	1	—
Other	1	2
Total operating revenues from affiliates	<u>\$ 8</u>	<u>\$ 8</u>
Purchased power from affiliate (Account 401)		
Generation(a)	\$ 120	\$ 179
Operating and Maintenance		
PHISCO(b)(d)	\$ —	\$ 165
PES(c)	—	9
Total Operating and Maintenance	<u>\$ —</u>	<u>\$ 174</u>
Operating and maintenance from affiliates		
BSC(b)	\$ 51	\$ 31
PHISCO(b)(d)	111	—
Other	—	1
Total operating and maintenance from affiliates	<u>\$ 162</u>	<u>\$ 32</u>
Capitalized costs:		
BSC(b)	\$ 28	\$ —
PHISCO(b)	25	—
Total capitalized costs	<u>\$ 53</u>	<u>\$ —</u>
Cash dividends paid to parent (Account 216)	\$ 96	\$ 112

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Contributions from parent (Account 211)	\$	151	\$	—
		As of December 31,		
		<u>2018</u>		<u>2017</u>
Payables to affiliates (current) (Account 234)				
Exelon Corporate	\$	1	\$	—
Generation(a)		7		12
BSC(b)		11		7
PHISCO(b)		12		27
Pepco		1		—
ACE		1		—
Total payables to affiliates (current)	<u>\$</u>	<u>33</u>	<u>\$</u>	<u>46</u>

- (a) DPL procures a portion of its electricity and gas supply requirements from Generation under its MDPSC and DPSC approved market based SOS and gas commodity programs.
- (b) DPL receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
- (c) PES performed underground transmission construction services, including services that are treated as capital costs, for DPL.
- (d) Due to the PHI entities' system conversion to Exelon's accounting systems on January 1, 2018, corporate support services received from PHISCO are reported in Operating and maintenance from affiliates in 2018.

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4				121,612,065	121,612,065
5					
6					
7					
8					
9				120,170,527	120,170,527
10					

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,662,253,851	3,934,483,353
4	Property Under Capital Leases	223,934	223,934
5	Plant Purchased or Sold		
6	Completed Construction not Classified	320,012,229	260,574,739
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,982,490,014	4,195,282,026
9	Leased to Others		
10	Held for Future Use	2,123,347	2,123,347
11	Construction Work in Progress	151,444,729	124,708,197
12	Acquisition Adjustments	50,046,281	50,046,281
13	Total Utility Plant (8 thru 12)	5,186,104,371	4,372,159,851
14	Accum Prov for Depr, Amort, & Depl	1,381,187,619	1,056,816,201
15	Net Utility Plant (13 less 14)	3,804,916,752	3,315,343,650
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,306,558,323	1,002,152,552
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	31,071,877	11,106,230
22	Total In Service (18 thru 21)	1,337,630,200	1,013,258,782
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	43,557,419	43,557,419
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,381,187,619	1,056,816,201

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
608,818,382				118,952,116	3
					4
					5
41,917,356				17,520,134	6
					7
650,735,738				136,472,250	8
					9
					10
7,414,408				19,322,124	11
					12
658,150,146				155,794,374	13
237,062,238				87,309,180	14
421,087,908				68,485,194	15
					16
					17
235,695,510				68,710,261	18
					19
					20
1,366,728				18,598,919	21
237,062,238				87,309,180	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
237,062,238				87,309,180	33

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 200 Line No.: 4 Column: b

Line item previously netted Capital Leases of \$223,934 with its associated Accumulated Amortization of \$223,934. Capital Lease Accumulated Amortization is now reported in FERC account 111 and shown in line 14, Accumulated Provision for Depreciation, Amortization and Depletion.

Schedule Page: 200 Line No.: 14 Column: b

Line item includes \$223,934 of Capital Lease Accumulated Amortization previously reported in FERC account 101 and shown in line 4, Property Under Capital Leases.

Schedule Page: 200 Line No.: 18 Column: b

Line item includes \$223,934 of Capital Lease Accumulated Amortization previously reported in FERC account 101 and shown in line 4, Property Under Capital Leases.

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
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			21
			22

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	2,341	
4	(303) Miscellaneous Intangible Plant	4,191,490	6,286,615
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	4,193,831	6,286,615
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)		

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	53,212,088	512,915
49	(352) Structures and Improvements	41,444,835	6,653,208
50	(353) Station Equipment	558,631,534	29,885,363
51	(354) Towers and Fixtures	74,067,046	
52	(355) Poles and Fixtures	416,248,927	107,323,658
53	(356) Overhead Conductors and Devices	256,837,399	46,681,375
54	(357) Underground Conduit	5,424,411	-5,756
55	(358) Underground Conductors and Devices	19,831,601	-64,121
56	(359) Roads and Trails	731,223	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,426,429,064	190,986,642
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	14,814,382	
61	(361) Structures and Improvements	38,065,709	1,608,856
62	(362) Station Equipment	373,528,606	27,806,120
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	197,557,299	11,172,540
65	(365) Overhead Conductors and Devices	325,705,488	27,118,565
66	(366) Underground Conduit	23,574,601	-93,039
67	(367) Underground Conductors and Devices	353,402,549	19,433,500
68	(368) Line Transformers	502,317,248	34,406,528
69	(369) Services	195,170,660	6,660,518
70	(370) Meters	126,736,780	2,377,942
71	(371) Installations on Customer Premises	39,885,723	2,815,025
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	62,626,927	3,060,598
74	(374) Asset Retirement Costs for Distribution Plant	2,631,341	2,410,104
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,256,017,313	138,777,257
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	2,684,231	
87	(390) Structures and Improvements	31,333,962	160,516
88	(391) Office Furniture and Equipment	3,017,738	4,139,021
89	(392) Transportation Equipment	173,757	172,452
90	(393) Stores Equipment	504,667	
91	(394) Tools, Shop and Garage Equipment	16,020,419	1,124,542
92	(395) Laboratory Equipment	186,456	
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	131,370,753	10,275,300
95	(398) Miscellaneous Equipment	2,952,388	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	188,244,371	15,871,831
97	(399) Other Tangible Property	4,735	
98	(399.1) Asset Retirement Costs for General Plant	138,909	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	188,388,015	15,871,831
100	TOTAL (Accounts 101 and 106)	3,875,028,223	351,922,345
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)	3,875,028,223	351,922,345

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
			2,341		3
		-3,777,532	6,700,573		4
		-3,777,532	6,702,914		5
					6
					7
					8
					9
					10
					11
					12
					13
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					46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
			53,725,003	48
16,027			48,082,016	49
2,640,973			585,875,924	50
89,237			73,977,809	51
5,388,614			518,183,971	52
4,482,221			299,036,553	53
			5,418,655	54
			19,767,480	55
			731,223	56
				57
12,617,072			1,604,798,634	58
				59
		-652,071	14,162,311	60
149,238			39,525,327	61
2,382,512			398,952,214	62
				63
893,655			207,836,184	64
4,066,046			348,758,007	65
			23,481,562	66
931,536			371,904,513	67
4,956,328			531,767,448	68
88,006			201,743,172	69
809,113			128,305,609	70
443,645			42,257,103	71
				72
381,732			65,305,793	73
			5,041,445	74
15,101,811		-652,071	2,379,040,688	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			2,684,231	86
179,983			31,314,495	87
		831,305	7,988,064	88
			346,209	89
			504,667	90
712,141			16,432,820	91
2,545			183,911	92
				93
651,451		1,194,759	142,189,361	94
			2,952,388	95
1,546,120		2,026,064	204,596,146	96
			4,735	97
			138,909	98
1,546,120		2,026,064	204,739,790	99
29,265,003		-2,403,539	4,195,282,026	100
				101
				102
				103
29,265,003		-2,403,539	4,195,282,026	104

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 67 Column: c

Account 367 & 368 were reported incorrectly in 2017. \$7,811 was listed under account 367 when it should have been listed under account 368. Addition balances in 2018 reflects the correct classification.

Schedule Page: 204 Line No.: 68 Column: c

Account 367 & 368 were reported incorrectly in 2017. \$7,811 was listed under account 367 when it should have been listed under account 368. Addition balances in 2018 reflects the correct classification.

Schedule Page: 204 Line No.: 88 Column: c

Account 392 & 391 were reported incorrectly in 2017. \$51,480 was listed under account 392 when it should have been listed under account 391. Addition balances in 2018 reflects the correct classification.

Schedule Page: 204 Line No.: 89 Column: c

Account 392 & 391 were reported incorrectly in 2017. \$51,480 was listed under account 392 when it should have been listed under account 391. Addition balances in 2018 reflects the correct classification.

Account 392 addition balance was adjusted by \$223,932 as leases are no longer presented net of depreciation.

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

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	Magnolia Substation Land: 11+Acres	Aug 2010	Dec 2025	1,180,361
3	Lakeside Substation Land; 8 Acres, Talbot County MD	Dec 2010	Dec 2025	406,468
4	2515 Old Ocean City Road, Salisbury, MD	Feb 2016	Jun 2019	346,301
5	0			
6	0			
7	Total of Land under \$250,000			190,217
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			2,123,347

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	Worcester - Ocean City Line 6724 Bay	36,190,215
2	DPL MD CAP - Centreville Plan	6,696,357
3	DPL MD CAP - GSRI PT 2 - Beaglin Substation	5,925,700
4	Router Upgrade Cores - Edges DE	3,478,607
5	Claymont AT20 Replacement	3,355,839
6	DPL MD CAP - GSRI PT 2 - Beaglin Substation Transmission	3,177,624
7	Crisfield Substation - New 69KV Terminal	2,352,814
8	Crisfield - Kings Creek - Construction	2,181,091
9	EMS Implementation Project Software	1,994,370
10	EMS Implementation Project Hardware	1,939,179
11	Router Upgrade Cores - Edges DPL MD	1,887,213
12	DPL Distribution Conversion	1,845,767
13	Hillsboro Substation - Spare Transformer	1,502,322
14	Silverside Substation - Purch Spare Transformer	1,397,533
15	DPL MD CAP - GSRI PT 2 - Transmission	1,380,016
16	Kiamensi Substation - Purch Spare Transformer	1,308,523
17	6727 Lynch Massey REA Rebuild	1,248,297
18	EMS Implementation Project Software	1,241,165
19	BIDA Customer Project Software	1,217,761
20	Crest Extend 4 New Feeders	1,182,680
21	Stockton Substation	1,144,659
22	13812 Hares Corner - Red Lion	1,134,971
23	DPL MD CAP GSRI PT2 6708N - Salisbury	1,116,952
24	Ocean City Substtion Upgrade - Worcest	1,109,784
25	Miscellaneous Plan Transmission DPL MD	1,061,044
26	Crisfield T1 Replace Transformer	1,036,812
27	Massey Install Line Bus Upgrade	1,018,919
28	Micellaneous projects under \$1,000,000	35,581,983
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	124,708,197

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	935,724,477	935,724,477		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	117,220,146	117,220,146		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	152,383	152,383		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	117,372,529	117,372,529		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	29,265,004	29,265,004		
13	Cost of Removal	24,661,016	24,661,016		
14	Salvage (Credit)	263,035	263,035		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	53,662,985	53,662,985		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17		2,718,531	2,718,531		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,002,152,552	1,002,152,552		

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

20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	362,144,323	362,144,323		
26	Distribution	580,765,260	580,765,260		
27	Regional Transmission and Market Operation				
28	General	59,242,969	59,242,969		
29	TOTAL (Enter Total of lines 20 thru 28)	1,002,152,552	1,002,152,552		

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 8 Column: c
 Depreciation related to the company's asset retirement obligations (ARO) totaling \$152,383 is reclassified to Other Regulatory Assets (182.3).

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4	SUBTOTAL			
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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19				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
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				42

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
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)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,568		
8	Transmission Plant (Estimated)	2,942,687	3,799,260	
9	Distribution Plant (Estimated)	32,598,182	33,691,357	
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)	35,564,437	37,490,617	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	35,564,437	37,490,617	

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		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	217,701.00	7,949,742		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	DE RPS RECs Purchased	657,098.00	17,780,596		
10					
11	MD HPS RECs Purchased	125.00	1,562		
12	MD RECs Received	331,803.00	1,387,864		
13					
14					
15	Total	989,026.00	19,170,022		
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Total	4,169.00	13,685		
21	Cost of Sales/Transfers:				
22	DE RECs Retired	640,793.00	17,602,082		
23	MD RECs Retired	333,728.00	1,400,677		
24					
25					
26					
27					
28	Total	974,521.00	19,002,759		
29	Balance-End of Year	228,037.00	8,103,320		
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						217,701.00	7,949,742	1
								2
								3
								4
								5
								6
								7
								8
						657,098.00	17,780,596	9
								10
						125.00	1,562	11
						331,803.00	1,387,864	12
								13
								14
						989,026.00	19,170,022	15
								16
								17
								18
								19
						4,169.00	13,685	20
								21
						640,793.00	17,602,082	22
						333,728.00	1,400,677	23
								24
								25
								26
								27
						974,521.00	19,002,759	28
						228,037.00	8,103,320	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 9 Column: b

Represents renewable energy credits acquired and received to meet the Renewable Energy Portfolio Standards (RPS) for the state of DE.

Schedule Page: 228 Line No.: 9 Column: c

Represents the dollar value of renewable energy credits acquired to meet the Renewable Energy Portfolio Standards (RPS) for the state of DE.

Schedule Page: 228 Line No.: 11 Column: b

Represents renewable energy credits acquired and received to meet the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 11 Column: c

Represents the dollar value of renewable energy credits acquired to meet the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 12 Column: b

Represents renewable energy credits transferred to DPL under the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 12 Column: c

Represents the dollar value of renewable energy credits transferred under the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 20 Column: b

Represents renewable energy credit reclassification of 4,079 prior year MD REC's from DPL to Pepco due to 2018 analysis as well as an adjustment of 90 to the beginning of year DE RPS REC quantity based on 2018 inventory tie-down.

Schedule Page: 228 Line No.: 20 Column: c

Represents the dollar value of renewable energy credit reclassification of prior year MD REC's from DPL to Pepco based on 2018 analysis. Note, there was no dollar value associated with the adjustment to the beginning of year DE RPS REC quantity based on 2018 inventory tie-down.

Schedule Page: 228 Line No.: 28 Column: b

Represents renewable energy credits retired under the Renewable Energy Portfolio Standards (RPS) for the states of DE and MD.

Schedule Page: 228 Line No.: 28 Column: c

Represents the dollar value of renewable energy credits retired under the Renewable Energy Portfolio Standards (RPS) for the states of DE and MD.

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		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

- 6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
- 7. Report on Lines 8-14 the names of vendors/transferees 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.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
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								39
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								41
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								46

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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21	Generation Studies				
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OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Wilmington Coal Gas-Site Clean Up	463,269		407.3	318,905	144,364
2	Deferred Fuel Costs	4,963,937		various	4,963,937	
3	Other Vacation Accrual	8,185,596	836,268	various	1,477,927	7,543,937
4	Asset Retirement Obligation	653,579	769,334	108.0	392,190	1,030,723
5	Transmission Service Revenue	7,549,595	13,125,989	456.1	7,038,383	13,637,201
6	DE Integrated Resource Planning (IRP)	822,116		407.3	358,741	463,375
7	DE Bluewater Wind Request for Proposal Costs	998,108		407.3	435,537	562,571
8	DE Bloom Energy Project	9,782	2,118,406	407.3	2,128,188	
9	DE Renewable Energy Portfolio Standards	495,687	18,030,030	407.3	18,525,717	
10	DE Electric Costs to Achieve (CTA) Deferral	3,862,181	3,033,901	407.3	1,410,008	5,486,074
11	FAS 133 DE Gas Derivatives	1,069,751	215,945	807.5	1,256,581	29,115
12	MD Bill Stabilization Adjustment Deferral	3,135,900	16,334,750	various	19,470,650	
13	MD Third Party Supplier Recovery	2,355,126	1,100,525	various	1,372,492	2,083,159
14	MD Costs to Achieve (CTA) Deferral	4,702,495	277,696	various	1,090,148	3,890,043
15	DE Third Party Supplier		1,404			1,404
16	Billing System-MD Recovery	1,326,784		903.0	321,644	1,005,140
17	MD Rate Case Costs	149,467	113,117	928.0	142,758	119,826
18	Smart Grid:					
19	DE DSM - Energy Efficiency	45,152				45,152
20	AMI / Smart Grid - DE	40,593,398	159,473	various	3,979,666	36,773,205
21	Recoverable DE DLC Costs	19,780,724	61,560	407.3	2,086,755	17,755,529
22	DE Gas IMU	8,038,534	21,208	various	699,511	7,360,231
23	DE Gas Costs to Achieve (CTA) Deferral	1,841,909	169,601	407.3	316,857	1,694,653
24	DE Gas IMU Battery Project Costs	2,833,189	619,524			3,452,713
25	DSM - Energy Efficiency Products MD	52,664,318	25,929,769	various	32,305,603	46,288,484
26	DSM - Direct Load Control Program MD	8,922,462	1,828,229	407.3	2,289,199	8,461,492
27	AMI / Smart Grid - MD	15,451,402	3,818,463	407.3	5,525,750	13,744,115
28	MD Dynamic Pricing-Critical Pk Rebate Credits		166,270	407.3	166,270	
29	AMI Loss on Retirement of Meters	13,123,094		407.3	1,342,904	11,780,190
30	Delaware SOS:					
31	DE SOS - Transmission	1,043,278	3,687,315	407.3	537,645	4,192,948
32	DE SOS - Administrative Costs	559,451	3,330,263	407.3	3,889,714	
33	Maryland SOS:					
34	MD SOS - Transmission	8,413,846	327,019	407.3	6,196,284	2,544,581
35	MD SOS - Administrative Costs	353,649	343,158	407.3	314,582	382,225
36	Storm Costs:					
37	MD Incremental Storm Costs	4,854,674	1,191,183	various	1,733,816	4,312,041
38	Tax Cuts and Jobs Act		1,761,387			1,761,387
39	MD RM54 Recovery		108,376			108,376
40						
41						
42						
43						
44	TOTAL	219,262,453	99,480,163		122,088,362	196,654,254

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

The following are the individual components of "Various"-

\$	4,934,591	recorded to account 407.3
	29,346	recorded to account 923.0
\$	4,963,937	Total

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

The following are the individual components of "Various"-

\$	25,981	recorded to account 184 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	25,616	recorded to account 236 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	392,277	recorded to account 242 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	1,034,053	recorded to account 923.0
\$	1,477,927	Total

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

The following is the individual component of "108":

\$	392,190	recorded to account 108 - change in estimate of cost of removal incurred related to Asset Retirement Obligations
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Schedule Page: 232 Line No.: 12 Column: d

The following are the individual components of "Various"-

\$	3,163,276	recorded to account 142 - Relief of Regulatory Asset through Billed Bill Stabilization Adjustment (BSA)
	8,115,205	recorded to account 254 - Reclass consistent with regulatory recovery position
	8,192,169	recorded to account 456.0
\$	19,470,650	Total

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

The following are the individual components of "Various"-

\$	633,681	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	562,804	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
	176,007	recorded to account 450.0
\$	1,372,492	Total

Schedule Page: 232 Line No.: 14 Column: d

The following are the individual components of "Various"-

\$	1,031,319	recorded to account 407.3
	57,937	recorded to account 182.3 - moved balances for more appropriate presentation within line "MD Rate Case costs"
	892	recorded to account 182.3 - moved balances for more appropriate presentation within line "AMI/Smart Grid - MD"
\$	1,090,148	Total

Schedule Page: 232 Line No.: 20 Column: b

The following lines from 2017 FERC Form 1, column (f) are individual components of 2018 beginning balance in column (b):

\$	(1,125,289)	Line 24	DE AMI Return in Rates
	31,500,201	Line 28	Recoverable DE Electric AMI Costs
	10,481,273	Line 29	Recoverable DE Dynamic Pricing Costs
	(248,009)	Line 27	DE AMI/DYP/DLC Return Reserve
	(14,778)	Line 18	MD Grid Resiliency Charge

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

\$ 40,593,398

Schedule Page: 232 Line No.: 20 Column: d

The following are the individual components of "Various"-
 \$ 3,909,855 recorded to account 407.3
 69,811 recorded to account 923.0
 \$ 3,979,666 Total

Schedule Page: 232 Line No.: 21 Column: b

The following lines from 2017 FERC Form 1, column (f) are individual components of 2018 beginning balance in column (b):
 \$ 871,249 Line 22 DE DSM - DLC Program
 (437,611) Line 27 DE AMI/DYP/DLC Return Reserve
 19,347,086 Line 30 Recoverable DE DLC Costs
 \$ 19,780,724

Schedule Page: 232 Line No.: 22 Column: b

The following lines from 2017 FERC Form 1, column (f) are individual components of 2018 beginning balance in column (b):
 \$ 458,580 Line 31 Return on DE Gas Smart Grid
 7,690,058 Line 32 DE Gas IMU Recovery
 (110,104) Line 33 DE Gas IMU Return Reserve
 \$ 8,038,534

Schedule Page: 232 Line No.: 22 Column: d

The following are the individual components of "Various"-
 \$ 629,009 recorded to account 407.3
 70,502 recorded to account 923.0
 \$ 699,511 Total

Schedule Page: 232 Line No.: 25 Column: b

The following lines from 2017 FERC Form 1, column (f) are individual components of 2018 beginning balance in column (b):
 \$ 56,498,501 Line 36 DSM - Energy Efficiency MD
 (3,834,183) Line 37 DSM - Energy Efficiency MD - CIF merger commitment
 \$ 52,664,318

Schedule Page: 232 Line No.: 25 Column: d

The following are the individual components of "Various"-
 27,021,807 recorded to account 407.3
 5,283,796 recorded to account 426.5
 \$ 32,305,603 Total

Schedule Page: 232 Line No.: 27 Column: b

The following lines from 2017 FERC Form 1, column (f) are individual components of 2018 beginning balance in column (b):
 \$ 1,551,232 Line 40, page 232 Smart Grid-MD
 16,180,194 Line 41, page 232 Recoverable MD AMI Costs
 1,028,507 Line 42, page 232 Recoverable MD Dynamic Pricing Costs
 454,446 Line 1, page 232.1 MD AMI Meters - Incremental Depreciation
 (3,762,977) Line 2, page 232.1 MD Electric AMI Savings
 \$ 15,451,402

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 37 Column: b

The following lines from 2017 FERC Form 1, column (f) are individual components of 2018 beginning balance in column (b):

\$	2,233,372	Line 14, page 232.1	MD Stella Incremental Storm Costs
	252,844	Line 15, page 232.1	MD Hurricane Irene Incremental Storm Costs
	167,468	Line 16, page 232.1	MD Derecho Incremental Storm Costs
	679,766	Line 17, page 232.1	MD Hurricane Sandy Incremental Costs
	665,457	Line 18, page 232.1	MD June 2015 Incremental Storm Costs
	855,767	Line 19, page 232.1	MD January 2016 Incremental Storm Costs
\$	4,854,674		

Schedule Page: 232 Line No.: 37 Column: d

The following are the individual components of "Various"-

\$	118,985	recorded to account 407.3
	24,299	recorded to account 408.1
	61,706	recorded to account 588.0
	1,380,177	recorded to account 593.0
	141,408	recorded to account 903.0
	7,241	recorded to account 908.0
\$	1,733,816	Total

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Prepaid Pension Costs	193,467,135	1,373,514	various	9,260,802	185,579,847
2	LT Customer Payment Receivables	409,535	652,864	143.0	940,510	121,889
3	LT Receivable from PJM		3,114,512	143.0	688,759	2,425,753
4	Other A/R Worker Compensation	1,721,598	588,615	various	1,902,438	407,775
5	Other		8,314			8,314
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	195,598,268				188,543,578

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 1 Column: a

The beginning of the year balances were changed to reflect the current year financial statement presentation.

Schedule Page: 233 Line No.: 1 Column: d

Prepaid pension is offset in accounts 926, 107 and 108.

Schedule Page: 233 Line No.: 4 Column: d

Worker's compensation is offset in accounts 925, 107 and 108.

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	87,830,061	69,421,057
3	Electric FAS109	119,415,229	128,741,286
4			
5			
6			
7	Other	557,534	557,534
8	TOTAL Electric (Enter Total of lines 2 thru 7)	207,802,824	198,719,877
9	Gas		
10	Gas	12,900,174	10,946,229
11	Gas FAS109	12,340,638	13,468,552
12			
13			
14			
15	Other	90,761	90,761
16	TOTAL Gas (Enter Total of lines 10 thru 15)	25,331,573	24,505,542
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	233,134,397	223,225,419

Notes

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Account 190 Fed Inc. Activity:
410 Debits      22,207,627
411 Credits      4,956,573
Net Debits      17,251,054

Account 190 State Inc. Activity:
410 Debits      6,366,273
411 Credits      1,089,930
Net Debits      5,276,343

Account 190 Activity B/S Only:
410 Debits      12,986,010
411 Credits      367,591
Net Debits      (12,618,419)

Net Change      (9,908,978)
    
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 18 Column: b

190	Electric	Gas	Total
Allowance for Doubtful Accounts	3,555,279	589,831	4,145,110
Charitable Contributions	557,534	90,762	648,296
Claims Reserve	475,914	77,474	553,388
Deferred ITC	654,230	106,502	760,732
Environmental Expense	460,282	50,704	510,986
Interest on Contingent Taxes	—	—	—
Merrill Creek	2,157,639	—	2,157,639
OPEB	3,249,306	528,956	3,778,262
Other (190)	1,512,853	1,699	1,514,552
Other Labor Related Accruals	4,803,497	781,965	5,585,462
Reg Asset - DSM	212,394	—	212,394
Reg Liab - FERC Formula Adj.	—	—	—
Reg Liab - Other	(1,207,257)	1,861,693	654,436
Renewable Energy Credits	2,850,827	—	2,850,827
FAS 109 Deferred Taxes - 190	250,839	40,835	291,674
FAS 109 Deferred Taxes - Property Gross Up	111,776,859	12,419,651	124,196,510
FAS 109 Deferred Taxes - Tax Cuts and Jobs Act Gross Up	15,120,113	1,962,333	17,082,446
Federal and State NOL	61,372,515	6,819,168	68,191,683
Total	207,802,824	25,331,573	233,134,397

Schedule Page: 234 Line No.: 18 Column: c

190	Electric	Gas	Total
Allowance for Doubtful Accounts	3,027,509	492,850	3,520,359
Charitable Contributions	557,534	90,761	648,295
Claims Reserve	479,514	78,060	557,574
Deferred ITC	560,263	91,206	651,469
Environmental Expense	290,911	47,358	338,269
Interest on Contingent Taxes	—	—	—
Merrill Creek	236,609	—	236,609
OPEB	4,366,702	710,859	5,077,561
Other (190)	5,444,769	886,358	6,331,127
Other Labor Related Accruals	5,141,753	837,030	5,978,783
Reg Asset - DSM	25,710	—	25,710
Reg Liab - FERC Formula Adj.	—	—	—
Reg Liab - Other	6,172,081	1,448,156	7,620,237
Renewable Energy Credits	554,953	455,942	1,010,895
FAS 109 Deferred Taxes - 190	214,812	34,969	249,781
FAS 109 Deferred Taxes - Property Gross Up	110,068,691	12,229,855	122,298,546
FAS 109 Deferred Taxes - Tax Cuts and Jobs Act Gross Up	16,676,563	2,113,082	18,789,645

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Federal and State NOL	44,901,503	4,989,056	49,890,559
Total	<u>198,719,877</u>	<u>24,505,542</u>	<u>223,225,419</u>

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 (Account 201)	1,000	2.25	
2	TOTAL	1,000		
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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)	
1,000	2,250					1
1,000	2,250					2
						3
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Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 250 Line No.: 1 Column: a

Reference is made to Footnote 18 - Shareholders' Equity in the Exelon Corporation Form 10-K, page 412, filed with the Securities and Exchange Commission for the year ended December 31, 2018.

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 210	
2		
3	Preferred Adjustable Rate	1,947,893
4	Common Stock - \$2.25 Par Value	318
5	Loss on Redemption of Preferred Stock	-609,815
6	Subtotal	1,338,396
7		
8		
9	ACCOUNT 211	
10		
11	General Corporate	-294,423,184
12	Allocation of non-acquisition debt from Holding Co. to Subsidiary	6,348,503
13	Capital Contribution from Parent	672,633,225
14	Subtotal	384,558,544
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40	TOTAL	385,896,940

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	9,924,450
2		
3		
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14		
15		
16		
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21		
22	TOTAL	9,924,450

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	Bonds (Account 221)		
2	Variable Rate Demand Exempt Facilities Bonds - 1993	15,500,000	275,796
3	Variable Rate Demand Exempt Facilities Bonds - 1994	30,000,000	440,787
4	Variable Rate Demand Exempt Facilities Bonds - 1999	22,330,000	334,028
5	Variable Rate Demand Exempt Facilities Bonds - 1999	11,000,000	
6	4% FMB due 6/1/2042	250,000,000	2,187,500
7			512,500 D
8	4.15% FMB due 5/15/2045	200,000,000	2,313,720
9			172,000 D
10	5.40% Medium Term Notes	78,400,000	1,406,618
11	3.50% FMB due 11/15/2023	300,000,000	2,572,640
12			126,000 D
13	3.50% FMB due 11/15/2023	200,000,000	1,861,600
14			4,264,000 D
15	4.15% FMB due 5/15/2045	175,000,000	1,531,250
16			-775,250 P
17	4.27% FMB due 6/15/2048	200,000,000	1,774,124
18	SUBTOTAL - Account 221	1,482,230,000	18,997,313
19			
20			
21			
22			
23	Account 224 - Other LTD		
24	Medium Term Notes 6.81% Series C	4,000,000	757
25			22,009 D
26	Medium Term Notes 7.61% Series C	12,000,000	6,209
27			189,913 D
28	Medium Term Notes 7.72% Series C	10,000,000	
29	SUBTOTAL - Account 224	26,000,000	218,888
30			
31			
32			
33	TOTAL	1,508,230,000	19,216,201

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
10/14/1993	10/1/2028	10/14/1993	10/1/2028	15,500,000	235,456	2
10/10/1994	10/1/2029	10/10/1994	10/1/2029	30,000,000	463,924	3
7/1/1999	7/1/2024	7/1/1999	7/1/2024	22,330,000	335,816	4
7/1/1999	7/1/2024	7/1/1999	7/1/2024	11,000,000	171,282	5
6/26/2012	6/1/2042	6/26/2012	6/1/2042	250,000,000	10,000,000	6
						7
5/11/2015	5/15/2045	5/11/2015	5/15/2045	200,000,000	8,300,000	8
						9
4/1/2010	2/1/2031	4/1/2010	2/1/2031	78,400,000	4,233,600	10
11/15/2013	11/15/2023	11/15/2013	11/15/2023	300,000,000	10,500,000	11
						12
6/9/2014	11/15/2023	6/9/2014	11/15/2023	200,000,000	7,000,000	13
						14
12/12/2016	5/15/2045	12/12/2016	5/15/2045	175,000,000	7,262,500	15
						16
6/21/2018	6/15/2048	6/21/2018	6/15/2048	200,000,000	4,507,222	17
				1,482,230,000	53,009,800	18
						19
						20
						21
						22
						23
1/9/1998	1/9/2018	1/9/1998	1/9/2018		6,053	24
						25
2/12/1997	12/2/2019	2/12/1997	12/2/2019	12,000,000	913,200	26
						27
2/7/1997	2/1/2027	2/7/1997	2/1/2027	10,000,000	772,000	28
				22,000,000	1,691,253	29
						30
						31
						32
				1,504,230,000	54,701,053	33

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 17 Column: d

\$200 million of First Mortgage Bonds were issued on June 21, 2018.

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

\$4 million of secured medium term notes matured on January 9, 2018.

Schedule Page: 256 Line No.: 32 Column: i

The difference between the total interest reported in column (i) and the balances in accounts 427 and 430 is \$17,976, which represents Service Company related interest from money pool transactions and credit facility commitment fees each of which are reported in account 430.

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	120,170,527
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal & State Income Tax	21,829,578
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See attached Footnote Data	-100,448,916
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	41,551,189
28	Show Computation of Tax:	
29	Federal Income Tax at 21%	8,725,750
30	Net Operating Loss Utilized	-13,868,928
31	2017 Return to Accrual	2,655,996
32	2017 Tax Reserve	
33		
34	TOTAL	-2,487,182
35		
36	Federal Income Tax Acct 409.10	-1,337,605
37	Federal Income Tax Acct 409.20	1,149,577
38	Total	-2,487,182
39		
40		
41		
42		
43		
44		

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 1 Column: b

Net Income for the Year (Page 117)	120,170,527
Federal Income Tax	3,167,126
State Income Tax	18,662,452
Pre-tax Book Income	142,000,105
 Increase (Decrease) in Taxable Income Resulting From:	
Removal Costs	(28,379,763)
Mixed Service Costs	(66,015,130)
Repair Allowance - Unit of Property	(53,591,350)
Bonus Depreciation	-
Depreciation	(16,074,855)
CIAC	7,645,905
AFUDC Equity	(2,439,758)
AFUDC Debt	(2,378,381)
Capitalized Interest	4,560,323
Gain/Loss on Disposition of Property	195,647
Other (Property)	307,824
Regulatory Assets & Liabilities	42,933,443
Pension/OPEB/SERP	7,384,277
Accrued Liabilities	1,645,422
Merger Commitment Deferrals	(1,094,716)
State Income Taxes Deductible	(206,260)
Other (Net)	5,058,456
Total Schedule M's	(100,448,916)
 Federal Taxable Income	 41,551,189
 Computation of Federal Income Tax:	
Federal Income Tax on Current Year Income (21%)	8,725,750
Net Operating Loss Utilized	(13,868,928)
2017 Return to Accrual	2,655,996
2017 Tax Reserve	-
Federal Income Tax	(2,487,182)
 Federal Income Tax Account 409.10	 (1,337,605)
Federal Income Tax Account 409.20	(1,149,577)
Total	(2,487,182)

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal Income Tax	47,495		-2,487,184	6,170,498	8,610,187
2	Federal RAR Adjustments					
3	State Income Tax			-87,016	-2,385	84,630
4	State RAR Adjustments					
5	Maryland Use Tax	866,760		-6,000	83,330	
6	Maryland Property Taxes		7,486,573	14,994,444	16,359,015	1,134,381
7	Other Maryland Taxes	120,582		8,699,174	8,790,122	
8	Delaware Property Taxes		8,349,875	16,817,419	18,402,087	795,117
9	Local Delaware Taxes	892,671		903,992	888,718	
10	Other Delaware Taxes	1,029,994		9,909,903	9,933,849	
11	Virginia Use Tax	1,067		2,535	4,669	
12	Virginia Property Taxes	60		189,496	190,022	466
13	West Virginia Property Taxes	13,194		-8,245	4,950	1
14	Mississippi Property Taxes	2,700		4,074		
15	New Jersey Property Taxes			652,440	652,440	
16	Pennsylvania Franchise					
17	Federal Excise Tax			31,398	31,398	
18	Payroll Taxes	1,140,186		4,003,854	3,895,850	
19						
20						
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22						
23						
24						
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39						
40						
41	TOTAL	4,114,709	15,836,448	53,620,284	65,404,563	10,624,782

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Report in columns (i) through (l) how the taxes were distributed. Report in column (i) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		-3,270,683			783,499	1
						2
		-78,314			-8,702	3
						4
777,430		-6,000				5
	7,716,763	14,994,444				6
29,634		8,699,174				7
	9,139,426	10,601,482			6,215,937	8
907,945		903,992				9
1,006,047		7,229,642			2,680,261	10
	1,066	2,535				11
		189,496				12
					-8,245	13
6,774					4,074	14
					652,440	15
						16
		27,197			4,201	17
1,248,190		3,426,011			577,843	18
						19
						20
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						40
3,976,020	16,857,255	42,718,976			10,901,308	41

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%				0		
3	4%	13,837			411.4	1,967	
4	7%	678,753			411.4	96,486	
5	10%	1,778,977			411.4	252,884	
6							
7							
8	TOTAL	2,471,567				351,337	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	10% Gas Utility	273,269				42,899	
11	Total Other	273,269	0		0	42,899	
12	Account 255	2,744,836				394,236	
13							
14							
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48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
11,870			3
582,267			4
1,526,093			5
			6
			7
2,120,230			8
			9
230,370			10
230,370			11
2,350,600			12
			13
			14
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			46
			47
			48

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Special Billing	2,720,140	143.0	1,243,454	824,764	2,301,450
2	DE Charitable Contributions	6,914,606	426.1	1,080,784		5,833,822
3	MD Charitable Contributions	1,313,274	426.1	182,120		1,131,154
4	MD MFN Credits	3,196,442	426.5	63,824	921,000	4,053,618
5	Supplier Deposits	609,186	131.0	635,364	696,471	670,293
6	Merrill Creek Lease	7,785,086	418.0	3,938,887	3,501,219	7,347,418
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46						
47	TOTAL	22,538,734		7,144,433	5,943,454	21,337,755

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 1 Column: a
The beginning of year balances were changed to reflect the current year financial statement presentation

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

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

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

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
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							10
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							12
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NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	936,312,275	58,259,732	36,090,939
3	Gas	104,034,698	6,473,303	4,010,104
4	Non Operations			
5	TOTAL (Enter Total of lines 2 thru 4)	1,040,346,973	64,733,035	40,101,043
6	FASB 109	-323,923,095		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	716,423,878	64,733,035	40,101,043
10	Classification of TOTAL			
11	Federal Income Tax	546,632,480	46,023,440	32,896,877
12	State Income Tax	169,791,398	18,709,595	7,204,166
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
	51,711	VARIOUS	16,337,470	VARIOUS	11,427,577	953,519,464	2
	5,746	VARIOUS	545,544			105,946,607	3
							4
	57,457		16,883,014		11,427,577	1,059,466,071	5
				254	4,949,603	-318,973,492	6
							7
							8
	57,457		16,883,014		16,377,180	740,492,579	9
							10
	40,358	VARIOUS	16,883,014	254	3,431,594	546,267,265	11
	17,099	VARIOUS		254	12,945,586	194,225,314	12
							13

NOTES (Continued)

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 9 Column: b

<u>282</u>	<u>Electric</u>	<u>Gas</u>	<u>Total</u>
Plant Related - APB 11 Deferred Taxes	961,715,870	106,857,319	1,068,573,189
Plant Related - FAS 109 Deferred Taxes	(306,038,999)	(34,004,333)	(340,043,332)
CIAC - Non Rate Base	(26,229,492)	(2,914,388)	(29,143,880)
Leased Vehicles - Non Rate Base	7,524,896	836,100	8,360,996
FAS 109 AFUDC Equity Deferred Taxes	6,935,923	770,658	7,706,581
FAS 109 1/1/2005 Deferred Tax Balance	873,292	97,032	970,324
Reg Liability - Other	-	-	-
Subtotal - p274	644,781,490	71,642,388	716,423,878
FASB 109	291,530,785	32,392,310	323,923,095
Adjusted Total	936,312,275	104,034,698	1,040,346,973

Schedule Page: 274 Line No.: 9 Column: k

<u>282</u>	<u>Electric</u>	<u>Gas</u>	<u>Total</u>
Plant Related - APB 11 Deferred Taxes	972,397,755	108,044,195	1,080,441,950
Plant Related - FAS 109 Deferred Taxes	(292,855,500)	(32,539,500)	(325,395,000)
CIAC - Non Rate Base	(26,643,462)	(2,960,385)	(29,603,847)
Leased Vehicles - Non Rate Base	7,765,171	862,797	8,627,968
FAS 109 AFUDC Equity Deferred Taxes	5,779,357	642,151	6,421,508
FAS 109 1/1/2005 Deferred Tax Balance	-	-	-
Reg Liability - Other	-	-	-
Subtotal - p275	666,443,321	74,049,258	740,492,579
FASB 109	287,076,143	31,897,349	318,973,492
Adjusted Total	953,519,464	105,946,607	1,059,466,071

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric Operations	154,401,625	8,220,468	27,587,259
4	Electric Non Operations	-3,002,599		
5	Other			
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	151,399,026	8,220,468	27,587,259
10	Gas			
11	Gas Operations	20,925,926	1,063,559	4,304,087
12	Gas Non Operations	-488,796		
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	20,437,130	1,063,559	4,304,087
18	FAS 109	-55,129,072		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	116,707,084	9,284,027	31,891,346
20	Classification of TOTAL			
21	Federal Income Tax	112,271,685	6,436,679	24,337,420
22	State Income Tax	4,435,399	2,847,348	7,553,926
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		VARIOUS	29,130,931	VARIOUS	36,684,448	142,588,351	3
466,292	205,367			VARIOUS	-466,288	-3,207,962	4
							5
							6
							7
							8
466,292	205,367		29,130,931		36,218,160	139,380,389	9
							10
				VARIOUS	607,839	18,293,237	11
75,908	33,432			VARIOUS	-75,906	-522,226	12
							13
							14
							15
							16
75,908	33,432				531,933	17,771,011	17
				254	6,343,174	-48,785,898	18
542,200	238,799		29,130,931		43,093,267	108,365,502	19
							20
375,911	165,561	VARIOUS	29,130,931	VARIOUS	9,680,184	75,130,547	21
166,289	73,238	VARIOUS		VARIOUS	33,413,083	33,234,955	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

<u>283</u>	<u>Electric</u>	<u>Gas</u>	<u>Total</u>
Blueprint for the Future	\$ 429,353	\$ 127,096	\$ 556,449
Deferred Fuel	—	1,367,624	1,367,624
Deferred Fuel Interest	—	8,133	8,133
Interest on Contingent Taxes	—	—	—
Materials Reserve	(110,340)	(17,962)	(128,302)
Merger Commitment Fees	(3,002,599)	(488,795)	(3,491,394)
Pension	46,930,188	7,639,798	54,569,986
Property Taxes	5,469,247	890,343	6,359,590
Reacquired Debt	1,829,115	297,763	2,126,878
Reg Asset - DSM	15,658,580	—	15,658,580
Reg Asset - FERC Formula Rate Adj.	2,092,373	—	2,092,373
Reg Asset - Other	36,760,272	3,867,857	40,628,129
Reg Asset- COPCO Acquisition Adjustment	1,407,823	—	1,407,823
Reg Liab - Other	(3,918,197)	(530,588)	(4,448,785)
Subtotal p276	103,545,815	13,161,269	116,707,084
FASB 109 Above if not separately removed	47,853,208	7,275,864	55,129,072
Total	\$ 151,399,023	\$ 20,437,133	\$ 171,836,156

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

<u>283</u>	<u>Electric</u>	<u>Gas</u>	<u>Total</u>
Blueprint for the Future	\$ —	\$ —	\$ —
Deferred Fuel	—	—	—
Deferred Fuel Interest	—	—	—
Interest on Contingent Taxes	—	—	—
Materials Reserve	(112,593)	(18,329)	(130,922)
Merger Commitment Fees	(3,207,962)	(522,226)	(3,730,188)
Pension	44,256,129	7,204,486	51,460,615
Property Taxes	4,017,656	654,037	4,671,693
Reacquired Debt	1,550,741	252,446	1,803,187
Reg Asset - DSM	14,011,050	—	14,011,050
Reg Asset - FERC Formula Rate Adj.	3,779,550	—	3,779,550
Reg Asset - Other	32,018,681	3,688,793	35,707,474
Reg Asset- COPCO Acquisition Adjustment	793,043	—	793,043
Reg Liab - Other	—	—	—
Subtotal p277	97,106,295	11,259,207	108,365,502
FAS109	42,274,094	6,511,804	48,785,898
Total	\$ 139,380,389	\$ 17,771,011	\$ 157,151,400

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	SFAS 109 Regulatory Liability:					
2	SFAS Electric	455,428,455	411.1	15,343,357	18,007,088	458,092,186
3	SFAS Gas	55,379,579	various	5,115,304	1,613,430	51,877,705
4	Maryland SOS:					
5	MD Energy	3,422,000	407.3	1,660,820	1,630,398	3,391,578
6	Delaware SOS:					
7	DE Energy	7,354,607	407.3	11,794,587	11,312,629	6,872,649
8	DE Administrative Costs		407.3	3,104,912	6,351,683	3,246,771
9	DE SOS Interest	140,894	431.0	225,646	370,110	285,358
10	DE Qualified Fuel Cell Facility	6,818,422	407.3	37,875,117	38,850,407	7,793,712
11	DE Renewable Energy Portfolio Standards		407.3	19,706,891	22,918,949	3,212,058
12	DE Deferred Fuel Costs-Gas	8,440,144	various	12,629,132	8,034,757	3,845,769
13	DE SFAS 133 Gas Derivatives		807.5	216,346	216,346	
14	DE Distribution Rate Reserve		various	5,143,489	6,781,545	1,638,056
15	DE Gas Rate Reserve				4,439,719	4,439,719
16	MD Grid Resiliency Charge	230,640			55,206	285,846
17	MD Dynamic Pricing - Critical Peak Rebate Credits	766,347	407.3	1,065,991	392,411	92,767
18	Tax Cuts and Jobs Act	(1,127,189)	142.0	6,218,442	13,317,280	5,971,649
19	DSM Direct Load Control Program-MD		407.3	855,084	1,579,633	724,549
20	DSM-Energy Efficiency Products-MD				4,248,468	4,248,468
21	MD RM54 Recovery		various	205,912	234,819	28,907
22	DE Electric Costs to Achieve (CTA) Deferral		142.0	3,057,772	3,057,772	
23	MD Bill Stabilization Adjustment Deferral		182.3	8,285,992	12,422,089	4,136,097
24	SOS Deferral for FERC 494 Settlement		407.3	3,510,375	10,748,493	7,238,118
25	DE PSC Refund				650,391	650,391
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	536,853,899		136,015,169	167,233,623	568,072,353

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 3 Column: d

The following are the individual components of "Various"-

\$	3,246,783	recorded to account 254.0; moved balance for more appropriate presentation within line 2 "SFAS Electric"
	32,192	recorded to account 283.0 - Reversal of SFAS 109 Regulatory liability deferred taxes
	1,836,329	recorded to account 411.1
\$	5,115,304	Total

Schedule Page: 278 Line No.: 12 Column: d

The following are the individual components of "Various"-

\$	91,666	recorded to account 431
	12,537,466	recorded to account 805.1
\$	12,629,132	Total

Schedule Page: 278 Line No.: 14 Column: d

The following are the individual components of "Various"-

\$	3,217,560	recorded to account 440
	1,774,248	recorded to account 442
	151,681	recorded to account 444
\$	5,143,489	Total

Schedule Page: 278 Line No.: 18 Column: d

The following is the individual component of "142":

\$	6,218,442	recorded to account 142 - Relief of Regulatory Liability through billing of one-time TCJA credits
----	-----------	---

Schedule Page: 278 Line No.: 21 Column: d

The following are the individual components of "Various"-

\$	48,542	recorded to account 903
	157,370	recorded to account 182.3 - due to change in cost recovery mechanism ordered by the Maryland Public Service Commission
\$	205,912	Total

Schedule Page: 278 Line No.: 22 Column: d

The following is the individual component of "142":

\$	3,057,772	recorded to account 142 - Relief of Regulatory Liability through billing of one-time merger synergy savings
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Schedule Page: 278 Line No.: 23 Column: d

The following is the individual component of "182.3":

\$	8,285,992	recorded to account 182.3 - Reclass consistent with regulatory recovery position
----	-----------	--

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	669,075,153	651,573,264
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	263,426,317	261,592,769
5	Large (or Ind.) (See Instr. 4)	22,263,583	24,037,515
6	(444) Public Street and Highway Lighting	13,826,714	13,996,161
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	968,591,767	951,199,709
11	(447) Sales for Resale	12,583,500	9,885,548
12	TOTAL Sales of Electricity	981,175,267	961,085,257
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	981,175,267	961,085,257
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,863,959	3,580,922
17	(451) Miscellaneous Service Revenues	752,442	1,883,135
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,720,266	5,434,250
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	20,561,275	21,272,192
22	(456.1) Revenues from Transmission of Electricity of Others	154,442,663	145,881,370
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	184,340,605	178,051,869
27	TOTAL Electric Operating Revenues	1,165,515,872	1,139,137,126

ELECTRIC OPERATING REVENUES (Account 400)

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

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

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

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,423,442	5,009,763	462,182	458,170	2
				3
5,193,114	5,049,689	62,186	61,466	4
1,836,734	1,772,705	364	385	5
44,969	44,149	623	636	6
				7
				8
				9
12,498,259	11,876,306	525,355	520,657	10
339,094	346,230			11
12,837,353	12,222,536	525,355	520,657	12
				13
12,837,353	12,222,536	525,355	520,657	14

Line 12, column (b) includes \$ -8,511,981 of unbilled revenues.
 Line 12, column (d) includes -61,169 MWH relating to unbilled revenues

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 17 Column: b

Items greater than \$250,000.00
Connect Charges \$ 660,861

Schedule Page: 300 Line No.: 17 Column: c

Items greater than \$250,000.00
Connect Charges \$ 1,522,410

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

Amounts over \$250,000
MD Bill Stabilization Adjustment \$ (4,333,343)
MD Calendar Revenue Normalization 2,522,773
Intercompany Revenue Previously Recorded to
Contra-expense 5,925,278
Intercompany Power Sales 672,818
Consolidated Billing and Account Management Fees 388,364
RPM Auction 14,408,750

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

Amounts over \$250,000
MD Bill Stabilization Adjustment \$ 14,295,037
Net Metering 775,685
Other Electric Revenue 607,801
Intercompany Power Sales 613,884
MD Bill Stabilization Adjustment Unbilled (5,349,322)

NOTE: \$9,913,739 of RPM auction revenue has also been reclassified from Line 11, Column c to Line 21, Column c to conform to the current period presentation.

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales					
2	R - Residential Sales	5,463,341	674,777,648	456,481	11,968	0.1235
3	PL - Private Area Lighting	5,725	1,757,988	4,419	1,296	0.3071
4	Unbilled Revenue	-45,624	-7,460,483			0.1635
5	Total	5,423,442	669,075,153	460,900	11,767	0.1234
6						
7						
8	442- Commerical & Industrial Sale					
9	GS - General Services Comm.	5,196,035	259,853,216	58,335	89,072	0.0500
10	GS - General Services Industrial	1,834,780	22,390,262	319	5,751,661	0.0122
11	PL - Private Area Lighting Comm.	14,295	4,401,800	3,626	3,942	0.3079
12	PL - Private Area Lighting Ind.	328	72,485	51	6,431	0.2210
13	Unbilled Revenue Comm.	-17,216	-785,440			0.0456
14	Unbilled Revenue Ind.	1,626	-242,423			-0.1491
15	Total	7,029,848	285,689,900	62,331	112,783	0.0406
16						
17	444- Public Street & Highway Ligh					
18	SL - Street Lighting	44,924	13,850,349	625	71,878	0.3083
19	Unbilled Revenue	45	-23,635			-0.5252
20	Total	44,969	13,826,714	625	71,950	0.3075
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,559,428	977,103,748	523,856	23,975	0.0778
42	Total Unbilled Rev.(See Instr. 6)	-61,169	-8,511,981	0	0	0.1392
43	TOTAL	12,498,259	968,591,767	523,856	23,858	0.0775

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PECO Energy	RQ	2	0	0	0
2	PJM Interconnection	OS	PJM	0	0	0
3	0		0	0	0	0
4	0		0	0	0	0
5	0		0	0	0	0
6	0		0	0	0	0
7	0		0	0	0	0
8	0		0	0	0	0
9	0		0	0	0	0
10	0		0	0	0	0
11	0		0	0	0	0
12	0		0	0	0	0
13	0		0	0	0	0
14	0		0	0	0	0
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
848		41,546		41,546	1
338,246		12,541,954		12,541,954	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
848	0	41,546	0	41,546	
338,246	0	12,541,954	0	12,541,954	
339,094	0	12,583,500	0	12,583,500	

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	479,405,666	468,486,743
77	(556) System Control and Load Dispatching	1,187,926	1,766,026
78	(557) Other Expenses	-2,744,582	11,189,734
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	477,849,010	481,442,503
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	477,849,010	481,442,503
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,689,713	4,679,022
84			
85	(561.1) Load Dispatch-Reliability	229,430	243,282
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	635,336	714,077
87	(561.3) Load Dispatch-Transmission Service and Scheduling	117,128	145,336
88	(561.4) Scheduling, System Control and Dispatch Services	14,154	8,776
89	(561.5) Reliability, Planning and Standards Development	164,385	410,172
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	4,144	2,586
93	(562) Station Expenses		
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	11,044,373	3,962,673
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	15,898,663	10,165,924
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	88,219	158,515
102	(569) Maintenance of Structures	32,028	244,783
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	30,450	647,075
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,083,783	3,525,997
108	(571) Maintenance of Overhead Lines	7,693,142	8,931,958
109	(572) Maintenance of Underground Lines		3,727
110	(573) Maintenance of Miscellaneous Transmission Plant	701,481	755,943
111	TOTAL Maintenance (Total of lines 101 thru 110)	12,629,103	14,267,998
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	28,527,766	24,433,922

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	11,585	9,243
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	11,585	9,243
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Exps (Total 123 and 130)	11,585	9,243
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	9,731,665	12,081,785
135	(581) Load Dispatching	4,213,145	4,679,947
136	(582) Station Expenses	13,539	544,823
137	(583) Overhead Line Expenses	1,519,204	2,111,429
138	(584) Underground Line Expenses	1,806,042	1,756,531
139	(585) Street Lighting and Signal System Expenses	-6,656	155,456
140	(586) Meter Expenses	3,202,839	3,438,283
141	(587) Customer Installations Expenses	314,266	358,714
142	(588) Miscellaneous Expenses	8,939,693	10,996,644
143	(589) Rents	1,707,365	1,477,845
144	TOTAL Operation (Enter Total of lines 134 thru 143)	31,441,102	37,601,457
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,985,998	1,379,704
147	(591) Maintenance of Structures	7,726	188,829
148	(592) Maintenance of Station Equipment	6,280,452	4,554,964
149	(593) Maintenance of Overhead Lines	28,981,613	32,449,025
150	(594) Maintenance of Underground Lines	5,092,534	4,039,450
151	(595) Maintenance of Line Transformers	1,563,145	38,980
152	(596) Maintenance of Street Lighting and Signal Systems	2,687,149	1,503,634
153	(597) Maintenance of Meters	1,101,968	422,553
154	(598) Maintenance of Miscellaneous Distribution Plant	1,595,195	2,586,614
155	TOTAL Maintenance (Total of lines 146 thru 154)	49,295,780	47,163,753
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	80,736,882	84,765,210
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	1,380,382	1,922,310
161	(903) Customer Records and Collection Expenses	46,768,268	50,023,058
162	(904) Uncollectible Accounts	4,672,431	2,673,630
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	52,821,081	54,618,998

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		283
168	(908) Customer Assistance Expenses	7,190,369	7,015,283
169	(909) Informational and Instructional Expenses	861,722	925,489
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	8,052,091	7,941,055
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		606,449
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		606,449
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	3,563,640	3,898,025
182	(921) Office Supplies and Expenses	5,964,905	256,287
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	74,855,427	62,170,591
185	(924) Property Insurance	491,763	532,303
186	(925) Injuries and Damages	1,262,692	400,516
187	(926) Employee Pensions and Benefits	7,999,345	14,544,073
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	4,418,266	5,255,798
190	(929) (Less) Duplicate Charges-Cr.		11,521,894
191	(930.1) General Advertising Expenses	383,314	212,864
192	(930.2) Miscellaneous General Expenses	7,980,151	7,520,959
193	(931) Rents		12,767
194	TOTAL Operation (Enter Total of lines 181 thru 193)	106,919,503	83,282,289
195	Maintenance		
196	(935) Maintenance of General Plant	19,478	5,317,803
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	106,938,981	88,600,092
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	754,937,396	742,417,472

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Direct Energy Business Marketing, LLC	OS				
2	DTE Energy Trading, Inc.	OS				
3	Engelhart CTP (US) LLC	OS				
4	Exelon Generation Company, LLC	OS				
5	Next Era Energy Power Marketing, LLC	OS				
6	PECO Energy Company	OS				
7	PJM Interconnection LLC	EX	PJM Tariff			
8	Shell Energy North America US, LP	OS				
9	TransCanada Power Marketing LTD	OS				
10	Vitol Inc.	OS				
11	Peak Energy Savings Credit	OS				
12	AES Armenia Mountain Wind, LLC	LU				
13	Chestnut Flats Wind, LLC	LU				
14	Roth Rock Wind Farm, LLC	LU				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Other RECs	OS				
2	Other RECs: AES, Roth Rock, Chestnut F	OS				
3	Washington Gas	OS				
4	Ecogy Pennsylvania Systems, LLC	OS				
5	SREC Trade, Inc	OS				
6	Duke Energy	OS				
7	Aspre Energy	OS				
8	Delaware Sustainable Energy Utility	OS				
9	Altre, LLC	OS				
10	Carbon Solutions Group	OS				
11	White Oaks Solar Energy LLC	OS				
12	EDF Trading	OS				
13	Avangrid Renewables, LLC	OS				
14	American Municipal Power, Inc.	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	ICAP Energy LLC	OS				
2	Karbone Inc.	OS				
3	SREC Trade Inc.	OS				
4	TFS Energy Futures LLC	OS				
5	0		0	0	0	0
6	0		0	0	0	0
7	0		0	0	0	0
8	0		0	0	0	0
9	0		0	0	0	0
10	0		0	0	0	0
11	0		0	0	0	0
12	0		0	0	0	0
13	0		0	0	0	0
14	0		0	0	0	0
	Total					

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
121,094				6,694,819		6,694,819	1
965,551				55,422,008		55,422,008	2
178,862				10,608,181		10,608,181	3
2,038,789				120,201,428		120,201,428	4
1,436,683				83,380,510		83,380,510	5
189				9,278		9,278	6
82,128			1,039,481	4,473,862	56,737,163	62,250,506	7
171,302				9,067,236		9,067,236	8
1,498,999				82,118,600		82,118,600	9
121,094				6,693,695		6,693,695	10
			2,582,421			2,582,421	11
131,804				12,142,691		12,142,691	12
97,346				8,167,898		8,167,898	13
109,095				9,061,141		9,061,141	14
6,952,936			3,621,902	419,001,317	56,782,447	479,405,666	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				14,037		14,037	1
				1,447,889		1,447,889	2
				158,656		158,656	3
				43,704		43,704	4
				75,504		75,504	5
				34,300		34,300	6
				40,500		40,500	7
				5,138,079		5,138,079	8
				552,195		552,195	9
				319,000		319,000	10
				2,568,979		2,568,979	11
				287,127		287,127	12
				140,000		140,000	13
				140,000		140,000	14
6,952,936			3,621,902	419,001,317	56,782,447	479,405,666	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					29,200	29,200	1
					4,200	4,200	2
					4,427	4,427	3
					7,457	7,457	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
6,952,936			3,621,902	419,001,317	56,782,447	479,405,666	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 2 Column: b

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 3 Column: b

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

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

Exelon Generation Company, LLC and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of December 31, 2018.

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

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 5 Column: b

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 6 Column: a

PECO Energy Company and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of December 31, 2018.

Schedule Page: 326 Line No.: 6 Column: b

Megawatt Hours which PECO customers consumed on PHI territory which was read by PHI but billed by PECO.

Schedule Page: 326 Line No.: 7 Column: l

Balancing Operating Reserve	213,247
Balancing Operating Reserve for Load Response	1,768
Day-ahead Scheduling Reserve	23,615
Load Reconciliation for Balancing Operating Reserve	226
Load Reconciliation for Day-ahead Scheduling Reserve	36
Load Reconciliation for Non- Synchronized Reserve	83
Load Reconciliation for Reactive Services	74
Load Reconciliation for Regulation & Frequency Response Service	874
Load Reconciliation for Synchronized Reserve	279
Network Integration Transmission Service	56,360,773
Non- Synchronized Reserve	2,787
Reactive Services	2,533
Reactive Supply & Voltage Control from Generation	43,210

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Delmarva Power & Light Company		04/02/2019	2018/Q4
FOOTNOTE DATA			

Regulation & Frequency Response Service	18,793
Synchronized Reserve	8,138
Synchronous Condensing	7
PJM Customer Payment Default	60,720
	56,737,163

Schedule Page: 326 Line No.: 8 Column: b

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 9 Column: b

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 10 Column: b

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

Schedule Page: 326 Line No.: 11 Column: b

Peak energy savings credit program designed to reduce energy usage during times of peak energy demand.

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

Megawatt Hours purchased from Armenia Mountain Wind, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 12/19/2024

Schedule Page: 326 Line No.: 13 Column: b

Megawatt Hours purchased from Chestnut Flats Wind, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 12/29/2031

Schedule Page: 326 Line No.: 14 Column: b

Megawatt Hours purchased from Roth Rock Wind Farm, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 08/03/2031

Schedule Page: 326.1 Line No.: 1 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Maryland.

Schedule Page: 326.1 Line No.: 2 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 3 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 4 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 5 Column: b

Represents retirement of renewable energy credits purchased on the open-market for

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Delaware.

Schedule Page: 326.1 Line No.: 6 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 7 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 8 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 9 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 10 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 11 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 12 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 13 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 14 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.2 Line No.: 1 Column: b

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 1 Column: I

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 2 Column: b

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 2 Column: I

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 3 Column: b

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 3 Column: I

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 4 Column: b

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 4 Column: 1

Represents broker fees on purchases of renewable energy credits.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PJM Point to Point Trans Revenue	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	PJM Trans Owner Sched. Sys Control			
3	PJM Network Integration Transmission Svc			
4	Other Transmission Agreements			
5	PJM Transmission Enhancement Credits			
6	AES NewEnergy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	Agera Energy, LLC - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Agera Energy, LLC - MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Ambit Energy (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Ambit Energy (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	American Power & Gas of MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	APN Starfirst, LP	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Atlantic Energy MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	BGE Home Products & Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	BlueStar Energy Services, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	BOC Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	Champion Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	Clearview Electric (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Clearview Electric (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	Commerce Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	Constellation NewEnergy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	Delmarva Power (DEN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	Delmarva Power (MDN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	Direct Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25	Discount Energy Group LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
26	East Coast Power & Gas of New Jersey LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
27	EDF Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
28	ELIGO	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
29	Energy Me - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
30	Energy Me - MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
31	Energy Plus Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
32	Ethical Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
33	First Point Power, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
34	First Point Power, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Freepoint Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	GDF Suez Retail Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
3	GEXA Energy Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
4	GEXA Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
5	Great American Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
6	Green Mountain Energy Company (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	Hess Energy Marketing, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Horizon Power & Light LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Hudson Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	IDT Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	Inspire Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	Kuehne Chemical Co	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Liberty Power Corp	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	Liberty Power Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	LifeEnergy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	Major Energy Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	Maryland Gas & Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	MidAmerican Energy Services, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	NextEra Energy Services Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	NextEra Energy Services Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	Palmco Power LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	Palmco Power LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	PBF Power Marketing, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	Perigee Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25	Plymouth Rock Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
26	PP&L EnergyPlus Co , LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
27	PP&L EnergyPlus Co , LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
28	Public Power of MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
29	Reliant Energy Northeast LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
30	ResCom Energy LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
31	Residents Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
32	Sempra Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
33	SFE Energy Maryland, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
34	SmartEnergy Holdings, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	SmartEnergy Holdings, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	Source Power & Gas LLC - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
3	Sperian Energy Corporation	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
4	Star Energy Partners, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
5	Starion Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
6	Stategic Energy LTD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	Stream Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Stream Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Tenaska Power Services Co	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Texas Retail Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	UGI Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	Viridian Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Washington Gas Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	XOOM Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	XOOM Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
OATT						1
						2
						3
						4
						5
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		832,745		6
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		136,238		7
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		73,992		8
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		9,392		9
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,752		10
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,998		11
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,692		12
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,196		13
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		8		14
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		20,277		15
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		224,259		16
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		93,753		17
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		13,764		18
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		9,077		19
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		71,263		20
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		892,314		21
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		-11,363		22
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		-10,418		23
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		927,299		24
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		879		25
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		98,472		26
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		16,126		27
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		121		28
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,063		29
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		19,952		30
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		6,045		31
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		11,935		32
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3,856		33
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,109		34
			0	6,555,634		0

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,360		1
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		247,586		2
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		43,419		3
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		40,370		4
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		538		5
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,899		6
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		12,760		7
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		9,068		8
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		549		9
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,959		10
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		6,300		11
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		73,214		12
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		15,180		13
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		48,171		14
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		57,933		15
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,822		16
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		19,142		17
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		166,497		18
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,965		19
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		388		20
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,978		21
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,364		22
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		323,721		23
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		27		24
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,419		25
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		628,146		26
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		60,063		27
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		34,251		28
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		66,306		29
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		834		30
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,648		31
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		280,602		32
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		20,941		33
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		14,354		34
			0	6,555,634		0

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		8,995		1
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		30,882		2
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3,693		3
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3,284		4
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		6,054		5
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		157,651		6
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,214		7
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,763		8
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		19,486		9
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		35,463		10
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		34,176		11
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		9,523		12
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		529,221		13
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		14,315		14
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		34,344		15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	6,555,634		0

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
		974,462	974,462	1
		1,494,139	1,494,139	2
		145,909,565	145,909,565	3
		4,415,331	4,415,331	4
		1,649,166	1,649,166	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	154,442,663	154,442,663	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	154,442,663	154,442,663	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
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				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	154,442,663	154,442,663	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: m

DPL share of PJM pool Point-to-Point transmission revenue from the administration of the PJM Interconnection, LLC Open Access Transmission Tariff (OATT).

Schedule Page: 328 Line No.: 2 Column: m

Revenue from PJM Interconnection, LLC for Transmission Owner Scheduling, System Control and Dispatch Service with the DPL Zone Control Center.

Schedule Page: 328 Line No.: 3 Column: m

Revenue from the PJM Interconnection, LLC for Network Integration Transmission Service and Other Supporting Facilities, specifically, ODEC and DEMEC with DPL.

Schedule Page: 328 Line No.: 4 Column: m

Revenue from Other Transmission Agreements, specifically, PSEG for LDV (Lower Delaware Valley) and PECO Energy for EHV/TEF (Extra High Voltage/Transmission Enhancement Facilities) agreements.

Schedule Page: 328 Line No.: 5 Column: m

Revenue from Transmission Enhancements.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	244,970
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Trustee Fees	9,757
7	Board of Director Expenses	81,600
8	Research, Development,	
9	and Demonstration, including Memberships	306,272
10	DE Environmental & Low Income and MD Universal Fund	7,126,730
11	Credit Card Accruals	197,821
12	Miscellaneous	13,001
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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41		
42		
43		
44		
45		
46	TOTAL	7,980,151

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			511,847		511,847
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	39,977,089				39,977,089
8	Distribution Plant	66,955,696				66,955,696
9	Regional Transmission and Market Operation					
10	General Plant	8,156,970				8,156,970
11	Common Plant-Electric	4,080,116				4,080,116
12	TOTAL	119,169,871		511,847		119,681,718

B. Basis for Amortization Charges

Consistent with the preceding year, Electric Intangible Plant Computer Software is amortized for a five year period using a straight line basis.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Transmission						
13	350.2	33,067	65.00		1.54	R3	
14	352	47,694	55.00	-20.00	2.00	S5	
15	353	578,919	50.00	-10.00	2.10	R2	
16	354	73,978	55.00	-25.00	2.27	R3	
17	355	503,465	38.00	-45.00	3.68	S0.5	
18	356	301,853	50.00	-50.00	2.60	S1	
19	357	5,419	40.00		2.50	R4	
20	358	19,767	40.00		2.50	R3	
21	359	731	50.00		2.00	R3	
22	SUBTOTAL	1,564,893					
23	Distribution						
24	360.2 DE	3,584	70.00		1.05	R4	
25	360.2 MD	4,086	60.00		1.31	R2	
26	361 DE	21,644	65.00	-10.00	1.27	R4	
27	361 MD	17,704	60.00	-15.00	1.79	R2	
28	362 DE	237,904	45.00	-20.00	2.08	R2	
29	362 MD	157,458	52.00	-25.00	2.02	R2.5	
30	364 DE	99,880	55.00	-100.00	2.25	R2	
31	364 MD	107,752	55.00	-125.00	2.99	R2	
32	365 DE	160,520	55.00	-100.00	1.53	R1.5	
33	365 MD	187,745	58.00	-100.00	2.30	R0.5	
34	366 DE	22,653	70.00	-5.00	0.84	S3	
35	366 MD	840	50.00		1.65	R3	
36	367 DE	202,897	52.00	-40.00	1.82	R3	
37	367 MD	167,471	40.00	-20.00	2.83	R3	
38	368 DE	284,908	45.00	-50.00	1.77	R2	
39	368 MD	244,785	35.00	-50.00	3.57	R1	
40	369.1 DE	17,800	65.00	-120.00	0.81	R4	
41	369.1 MD	8,536	65.00	-75.00	2.17	R4	
42	369.2 DE	93,373	55.00	-60.00	1.36	S3	
43	369.2 MD	81,846	45.00	-25.00	2.21	S6	
44	370 DE	12,879	25.00	-3.00	2.77	L0.5	
45	370 MD	5,358	30.00		4.72	S3	
46	370.1 DE	66,979	15.00	-3.00	8.13	S2	
47	370.1 MD	42,778	15.00		11.18	S3	
48	371.1 DE	31,092	18.00	-40.00	8.20	R2	
49	371.1 MD	11,038	42.00	-50.00	2.83	S1.5	
50	373 DE	54,458	38.00	-30.00	0.95	R2	

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	373 MD	10,740	33.00	-30.00	3.81	SC	
13	SUBTOTAL	2,358,708					
14	GENERAL						
15	390 DE	5,587	50.00	-10.00	1.01	R3	
16	390 MD	25,728	35.00	-10.00	3.48	R1.5	
17	391.1 DE	447	19.00	5.00	5.38	L2	
18	391.2 DE	2,306	20.00		5.65	SQ	
19	391.1 MD	520	15.00		6.68	SQ	
20	391.3 MD	242	5.00		10.00	SQ	
21	391.3 DE	4,214	5.00		21.49	SQ	
22	393 DE	505	25.00		19.74	SQ	
23	394 DE	9,858	25.00		6.32	SQ	
24	394.1 DE	-1	36.00		2.78	L1	
25	394 MD	11,486	15.00		6.67	SQ	
26	395 DE	185	20.00		15.46	SQ	
27	397 MD	12,788	35.00	-10.00	3.09	S3	
28	397 DE	60,513	25.00		4.13	L3	
29	397.1 MD	19,728	15.00		6.90	S3	
30	397.1 DE	14,057	15.00		6.98	S2	
31	397.3 MD	26,619	15.00		6.67	SQ	
32	397.3 DE	6,526	15.00		6.89	SQ	
33	398 DE	1,029	20.00		5.74	SQ	
34	398 MD	1,924	15.00		6.67	SQ	
35	SUBTOTAL	204,261					
36	COMMON						
37	390.3	43,160	75.00	-5.00	0.80	S1.5	
38	390.3a	7,151	75.00	-5.00	0.73	S1.5	
39	390.3b	781	40.00	-20.00	-0.09	R2	
40	391.1	5,735	20.00		5.38	SQ	
41	391.3	2,956	5.00		36.45	SQ	
42	393	196	25.00		6.27	SQ	
43	394	6,424	25.00		6.56	SQ	
44	397.1	149	20.00	5.00	4.75	L2	
45	397.1a	19,377	15.00		6.63	S2	
46	397.3	4,408	15.00		0.09	SQ	
47	398	7,982	20.00		5.22	SQ	
48	398.1a	-45	20.00		5.74	SQ	
49	SUBTOTAL	98,274					
50							

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Delaware				
2	2016 DE Base Rate Case 16-0649		1,763	1,763	
3	2017 DE Base Rate Case 17 0977		671,809	671,809	
4	DE Rate Case No 13-115		385	385	
5	General Regulation Legal		356,399	356,399	
6	Regulatory Commission Expense		70,974	70,974	
7	DPSC Reliability Docket 50		1,464	1,464	
8	0				
9	Maryland				
10	2016 MD Base Rate Case 9424		70,337	70,337	
11	2017 MD Base Rate Case 9455		75,428	75,428	
12	2018 DPL MD Base Rate Case		5,979	5,979	
13	Regulatory Commission Expense		3,835	3,835	
14	MD Grid Future Proceeding		40,455	40,455	
15	General Regulation Legal		156,664	156,664	
16	0				
17	Transmission:				
18	ER05-515 Annual Rate Updates FERC Transmission		268,629	268,629	
19	ER18-903 FAS 109 Tax Filing- FERC Transmission		19,340	19,340	
20	DEMEC Formal Challenge - FERC Transmission		17,834	17,834	
21	EL15-79 (TranSource) - FERC Transmission		67,696	67,696	
22	0				
23	Regulatory Tax Assessment	2,589,275		2,589,275	
24	0				
25	0				
26	0				
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	2,589,275	1,828,991	4,418,266	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
0	0			0			1
Electric	928	1,763		0			2
Electric	928	671,809		0			3
Electric	928	385		0			4
Electric	928	356,399		0			5
Electric	928	70,974		0			6
Electric	928	1,464		0			7
0	0			0			8
0	0			0			9
Electric	0			928	70,337		10
Electric	928	58,185		928	17,243		11
Electric	928	5,979		0			12
Electric	928	3,835		0			13
Electric	928	40,455		0			14
Electric	928	156,664		0			15
0	0			0			16
0	0			0			17
Electric	928	268,629		0			18
Electric	928	19,340		0			19
Electric	928	17,834		0			20
Electric	928	67,696		0			21
0	0			0			22
Electric	928	2,589,275					23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
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							40
							41
							42
							43
							44
							45
		4,330,686			87,580		46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	A. Electric R, D and D Perform Internally:	
2	(2) Transmission and (3) Distribution	Other - 5 Projects (less than \$50K)
3		
4		
5	B. Electric R, D and D Perform Externally:	
6	(1) Research Support to Electric Power	Membership - EPRI
7	Research Institute	
8		
9		
10	(4) Research Support to Others	Membership - National Electric
11		Energy, Testing, Research, and
12		Application Center
13		(Georgia Tech Research Corp)
14		
15		
16		Membership - Power Systems Engineering Research Center
17		(Arizona State University)
18		
19		Membership - Centre for Energy Advancement through Technical
20		Innovation (CEATI)
21		Membership - Northeast Gas Association
22		
23		Membership - Utility Health Sciences Group
24		
25		
26		
27		
28		
29	Total	
30		
31		
32		
33		
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35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
- (3) Research Support to Nuclear Power Groups
- (4) Research Support to Others (Classify)
- (5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
50,567		930.2	50,567		2
					3
					4
					5
	219,062	930.2	219,062		6
					7
					8
					9
					10
					11
					12
	11,116	930.2	11,116		13
					14
					15
					16
	3,474	930.2	3,474		17
					18
	13,304	930.2	13,304		19
					20
	3,675	930.2	3,675		21
					22
	5,074	930.2	5,074		23
					24
					25
					26
					27
					28
50,567	255,705		306,272		29
					30
					31
					32
					33
					34
					35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	1,422,976		
49	Administrative and General	2,013		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	1,787,717		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	430,663		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	536,126		
56	Transmission (Lines 35 and 47)	1,013,257		
57	Distribution (Lines 36 and 48)	6,397,284		
58	Customer Accounts (Line 37)	454,586		
59	Customer Service and Informational (Line 38)	9,315		
60	Sales (Line 39)	118,831		
61	Administrative and General (Lines 40 and 49)	658,903		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	9,618,965	2,106,226	11,725,191
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	41,688,682	9,222,030	50,910,712
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	34,747,686	9,069,092	43,816,778
69	Gas Plant	4,833,879	1,081,787	5,915,666
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	39,581,565	10,150,879	49,732,444
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,848,421	912,540	4,760,961
74	Gas Plant	241,154	54,806	295,960
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,089,575	967,346	5,056,921
77	Other Accounts (Specify, provide details in footnote):			
78	Expenses from Merchandising, Jobbing, & Contract Work - 416	2,421,242	305,379	2,726,621
79	Expenses of Non-Utility Operations - 417.1	11,449	2,672	14,121
80	Donations - 426.1	22,275	6,196	28,471
81	Exp. For Certain Civic, Political & Related Activities - 426.	6,369	1,284	7,653
82	Other Deductions - 426.5	18,847	4,251	23,098
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,480,182	319,782	2,799,964
96	TOTAL SALARIES AND WAGES	87,840,004	20,660,037	108,500,041

Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report End of <u>2018/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant in Service

Acct	Beginning Bal	Additions	Retirements	Transfers/Adj	Ending Balances
301	736,500	-	-	-	736,500
303	18,156,995	16,654,469	-	7,290	34,818,754
389.1	1,621,110	-	-	-	1,621,110
390.3	49,903,106	2,151,788	(79,431)	-	51,975,463
391.1	5,820,978	162,137	(334,898)	-	5,648,217
391.3	3,003,963	(17,886)	-	(7,290)	2,978,787
393	147,566	48,789	-	-	196,355
394	6,424,143	(384)	-	-	6,423,759
397	23,818,249	299,768	(33,604)	-	24,084,413
398	7,820,318	179,763	(11,189)	-	7,988,892
	117,452,928	19,478,444	(459,122)	-	136,472,250

Acct	Electric	Gas	Total Common Utility Plant	E = 81.83% G = 18.17%
301	602,678	133,822	736,500	
303	28,492,186	6,326,568	34,818,754	
389.1	1,326,554	294,556	1,621,110	
390.3	42,531,521	9,443,942	51,975,463	
391.1	4,621,936	1,026,281	5,648,217	
391.3	2,437,541	541,246	2,978,787	
393	160,677	35,678	196,355	
394	5,256,562	1,167,197	6,423,759	
397	19,708,275	4,376,138	24,084,413	
398	6,537,310	1,451,582	7,988,892	
	111,675,240	24,797,010	136,472,250	

Accumulated Provision for Depreciation of Common Utility Plant

DPL

12/31/2018

	Total Common	Electric	Gas
Balance at Beginning of Year	65,621,846	53,712,576	11,909,270

Depreciation Provision for the
Year Charged to:

403 Depreciation Expense	3,910,507	3,199,968	710,539
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Net Charges for Plant Retired:

Book Charges for Plant Retired

Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report End of <u>2018/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Cost of Removal, Net of Salvage	(821,802)	(672,481)	(149,321)
Other Debit or Credit Items:			
Transfers / Adjustments	(290)	(237)	(53)
Gain from Sale	-	-	-
Electric & Gas Allocator Adjustment		(14,219)	14,219
Balance at End of Year	68,710,261	56,225,607	12,484,654

Accumulated Provision for Amortization of Common Utility Plant
DPL
12/31/2018

	Total Common	Electric	Gas
Balance at Beginning of Year	17,523,048	14,396,936	3,126,112
Depreciation Provision for the Year Charged to:			
404 Amortization Expense	1,075,581	880,148	195,433
Net Charges for Plant Retired:			
Book Charges for Plant Retired			
Cost of Removal, Net of Salvage	-	-	-
Other Debit or Credit Items			
Transfers / Adjustments	290	237	53
Electric & Gas Allocator Adjustment	-	(57,826)	57,826
Balance at End of Year	18,598,919	15,219,495	3,379,424

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	2,613,383	3,886,903	4,225,878	4,680,385
3	Net Sales (Account 447)	(5,329,020)	(7,718,716)	(9,152,657)	(12,541,954)
4	Transmission Rights	11,966,917	25,095,241	40,631,175	56,360,773
5	Ancillary Services	152,847	218,381	342,636	318,507
6	Other Items (list separately)				
7	Demand	487,440	862,669	956,386	1,039,481
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	9,891,567	22,344,478	37,003,418	49,857,192

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	6,952,936	MWH	47,540	13,508,570	MWH	1,494,139
2	Reactive Supply and Voltage		MWH	43,210			
3	Regulation and Frequency Response		MWH	19,668			
4	Energy Imbalance						
5	Operating Reserve - Spinning		MWH	8,417			
6	Operating Reserve - Supplement						
7	Other		MWH	244,376			
8	Total (Lines 1 thru 7)	6,952,936		363,211	13,508,570		1,494,139

Name of Respondent Delmarva Power & Light Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
FOOTNOTE DATA			

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

The number of units reported on Line #2, Column (b) is 6,952,936 MWH.

Schedule Page: 398 Line No.: 3 Column: b

The number of units reported on Line #3, Column (b) is 6,952,936 MWH.

Schedule Page: 398 Line No.: 5 Column: b

The number of units reported on Line #5, Column (b) is 6,952,936 MWH.

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

The number of units reported on Line #7, Column (b) is 6,952,936 MWH.

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

Other Ancillary Services Purchased are as follow:

Balancing Operating Reserve	\$ 215,242
Day-ahead Scheduling Reserve	23,650
Non-Synchronized Reserve	2,870
Reactive Services	2,607
Synchronous Condensing	7
	\$ 244,376

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.

(2) Report on Column (b) by month the transmission system's peak load.

(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).

(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	3,794	5	1900	2,800	994				
2	February	3,101	2	1900	2,188	912				
3	March	2,787	21	2000	1,984	802				
4	Total for Quarter 1				6,972	2,708				
5	April	2,415	11	700	1,579	837				
6	May	3,134	26	1700	2,157	977				
7	June	3,563	30	1800	2,546	1,017				
8	Total for Quarter 2				6,282	2,831				
9	July	3,945	2	1800	2,936	1,009				
10	August	3,900	29	1800	2,765	1,135				
11	September	3,765	6	1700	2,644	1,121				
12	Total for Quarter 3				8,345	3,265				
13	October	2,886	4	1700	1,910	977				
14	November	2,751	28	1900	1,921	829				
15	December	2,900	11	800	1,996	904				
16	Total for Quarter 4				5,827	2,710				
17	Total Year to Date/Year				27,426	11,514				

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
- (2) Report on Column (b) by month the transmission system's peak load.
- (3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
- (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	12,498,259
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	848
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	338,246
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	27,093
7	Other		27	Total Energy Losses	644,124
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	13,508,570
9	Net Generation (Enter Total of lines 3 through 8)				
10	Purchases	6,952,936			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	6,555,634			
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	6,555,634			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	13,508,570			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,363,201	41,203	3,794	5	1900
30	February	1,017,978	34,401	3,101	2	1900
31	March	1,145,011	37,234	2,787	21	2000
32	April	947,028	32,406	2,415	11	700
33	May	1,009,947	22,129	3,134	26	1700
34	June	1,100,085	19,042	3,563	30	1800
35	July	1,295,940	14,502	3,945	2	1800
36	August	1,346,332	15,713	3,900	29	1800
37	September	1,115,360	18,609	3,765	6	1700
38	October	992,932	34,434	2,886	4	1700
39	November	1,032,204	34,257	2,751	28	1900
40	December	1,142,552	35,164	2,900	11	800
41	TOTAL	13,508,570	339,094			

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		
6	Net Peak Demand on Plant - MW (60 minutes)		
7	Plant Hours Connected to Load		
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water		
10	When Limited by Condenser Water		
11	Average Number of Employees		
12	Net Generation, Exclusive of Plant Use - KWh		
13	Cost of Plant: Land and Land Rights		
14	Structures and Improvements		
15	Equipment Costs		
16	Asset Retirement Costs		
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr		
20	Fuel		
21	Coolants and Water (Nuclear Plants Only)		
22	Steam Expenses		
23	Steam From Other Sources		
24	Steam Transferred (Cr)		
25	Electric Expenses		
26	Misc Steam (or Nuclear) Power Expenses		
27	Rents		
28	Allowances		
29	Maintenance Supervision and Engineering		
30	Maintenance of Structures		
31	Maintenance of Boiler (or reactor) Plant		
32	Maintenance of Electric Plant		
33	Maintenance of Misc Steam (or Nuclear) Plant		
34	Total Production Expenses		
35	Expenses per Net KWh		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned		
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		
41	Average Cost of Fuel per Unit Burned		
42	Average Cost of Fuel Burned per Million BTU		
43	Average Cost of Fuel Burned per KWh Net Gen		
44	Average BTU per KWh Net Generation		

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
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			5
			6
			7
			8
			9
			10
			11
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			14
			15
			16
0	0	0	17
0	0	0	18
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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

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

Name of Respondent
Delmarva Power & Light Company

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

Date of Report
(Mo, Da, Yr)
04/02/2019

Year/Period of Report
End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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			3
			4
			5
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			9
			10
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			12
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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
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11						
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14						
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16						
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46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
						3
						4
						5
						6
						7
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						14
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	500 KV Line (wholly owned)		500.00	500.00	sc steel	15.55		3
2								
3	230 KV Lines		230.00	230.00	various	387.32	83.64	25
4								
5	138 KV Lines		138.00	138.00	various	503.95	82.53	80
6								
7	69 KV Lines		69.00	69.00	various	556.19	13.02	73
8								
9	Underground Lines	5.46 mi. / 138, 2.21 mi/69				7.68		12
10	SEE DETAIL ON	FOLLOWING PAGES						
11	JOINT VENTURES							
12								
13	EHV System		500.00	500.00	steel tower	127.00		1
14	LDV System		500.00	500.00	stl/alm tower	154.00		6
15	SE System		500.00	500.00	steel tower			
16	(15)-(17) Above							
17	Non-Specific Line charges							
18	(All KV Inclusive)							
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35	Line Expenses							
36					TOTAL	2,658.51	345.36	310

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Red Lion	Hope Creek	500.00	500.00	steel towers	3.79		1
2	Keeney	Rock Springs	500.00	500.00	steel towers	3.79		1
3	Keeney	Red Lion	500.00	500.00	steel towers	7.98		1
4	Keeney	Steele	230.00	230.00	steel towers		57.20	1
5	Indian River	Piney Grove	230.00	230.00	wood H frame	25.83		1
6	Red Lion	Cedar Creek	230.00	230.00	steel poles	20.95		1
7	Cedar Creek	Milford	230.00	230.00	steel poles	42.84		1
8	Red Lion	Cartanza	230.00	230.00	steel poles	33.24	4.31	1
9	Cartanza	Milford	230.00	230.00	steel poles	26.50		1
10	Milford	Indian River	230.00	230.00	steel poles	26.37		1
11	Milford	Cool Spring	230.00	230.00	wood H frame	14.95		1
12	Indian River	Cool Spring	230.00	230.00	wood H frame	11.54		1
13	Milford	Steele	230.00	230.00	wood H frame	23.39		1
14	Colora	Nottingham	230.00	230.00	steel towers	1.76		1
15	Colora	Crest	230.00	230.00	steel poles	7.57		1
16	Claymont Sub	Linwood	230.00	230.00	steel poles	0.99		1
17	Edgemoor	Linwood	230.00	230.00	steel poles		8.10	1
18	Colora	Conowingo	230.00	230.00	steel poles	1.92		1
19	Crest	Cecil	230.00	230.00	steel poles	8.45		1
20	Keeney	Steele	230.00	230.00	steel towers	57.07		1
21	Keeney	Harmony	230.00	230.00	steel poles	6.14		1
22	Keeney	Red Lion	230.00	230.00	steel towers	8.05		1
23	Harmony	Edge Moor	230.00	230.00	steel poles	11.87		1
24	Keeney	Harmony	230.00	230.00	steel poles	9.30	0.20	1
25	Edge Moor	Claymont	230.00	230.00	steel poles	7.07		1
26	Hay Road	Red Lion	230.00	230.00	steel poles	10.72	13.83	1
27	Cartanza	Garrison	230.00	230.00	steel poles	2.63		1
28	Steele	Vienna	230.00	230.00	wood H frame	28.17		
29	Church	Steele	138.00	138.00	steel poles	25.69		1
30	Milford	Milford City	138.00	138.00	wood poles	0.24		1
31	Nelson	Indian River	138.00	138.00	wood H frame	21.41		1
32	Cheswold	Felton	138.00	138.00	wood poles	14.38		1
33	Indian River	Robinsonville	138.00	138.00	wood poles	11.74		1
34	Robinsonville	Rehoboth	138.00	138.00	steel poles	6.90		1
35	Vienna	Nelson	138.00	138.00	wood H frame	13.68		1
36					TOTAL	2,658.51	345.36	310

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Felton	South Harrington	138.00	138.00	wood poles	8.49		1
2	Vienna	Vienna (AT20)	138.00	138.00	wood poles	0.17		1
3	Easton	Steele	138.00	138.00	steel poles	23.62		1
4	Loretto	Kings Creek	138.00	138.00	wood H frame	7.18		1
5	Kings Creek	Pocomoke	138.00	138.00	wood H frame	9.14		1
6	Indian River	Bishop	138.00	138.00	steel poles	12.33		1
7	Indian River	Bishop	138.00	138.00	steel poles	7.24	5.18	1
8	Oak Hall	Eastern Shore Solar	138.00	138.00	steel poles	0.07		1
9	Church	Carville	138.00	138.00	steel poles	0.13	17.58	1
10	Kings Creek	Great Bay	138.00	138.00	steel poles	0.10		1
11	Ocean Bay	138th Street	138.00	138.00	wood poles	2.97		1
12	138th Street	Bethany	138.00	138.00	steel poles	6.13		1
13	Roxana	Bethany	138.00	138.00	wood H frame	3.65		1
14	Indian River	Roxana	138.00	138.00	wood H frame	8.54		1
15	Indian River AT20	Indian River 138	138.00	138.00	steel poles	0.26		1
16	Indian River AT22	Indian River 138	138.00	138.00	steel poles	0.29		1
17	Steele	Hillsboro	138.00	138.00	wood H frame	7.24		1
18	New Church	Oak Hall	138.00	138.00	wood poles	3.68		1
19	Piney Grove	New Church	138.00	138.00	wood H frame	21.80		1
20	New Church	Oak Hall	138.00	138.00	wood H frame	3.56		1
21	Indian River	Conaway	138.00	138.00	wood H frame	8.50		1
22	Conaway	N. Seaford	138.00	138.00	wood H frame	16.94		1
23	Clayton	Cheswold	138.00	138.00	wood poles	6.63		1
24	N. Seaford	S. Harrington	138.00	138.00	wood poles	16.22		1
25	Clayton	DEMEC	138.00	138.00	steel poles	0.69		1
26	Farmview	Milford	138.00	138.00	wood poles	2.44		1
27	Farmview	S. Harrington	138.00	138.00	wood poles	7.73		1
28	Piney Grove	Loretto	138.00	138.00	wood H frame	9.49		1
29	Bishop	Worcester	138.00	138.00	wood H frame	5.33		1
30	Loretto	Vienna	138.00	138.00	wood H frame	19.44		1
31	Bishop	Ocean Bay	138.00	138.00	wood H frame	9.97		1
32	Pocomoke	Oak Hall	138.00	138.00	wood H frame	8.57		1
33	Hillsboro	Wye Mills	138.00	138.00	wood H frame	8.59		1
34	Wattsville	Oak Hall	138.00	138.00	steel poles	3.91		1
35	Glasgow	Mt Pleasant	138.00	138.00	steel poles	10.99		1
36					TOTAL	2,658.51	345.36	310

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Red Lion West	Reybold	138.00	138.00	steel poles	1.11		1
2	New Castle	Town of New Castle	138.00	138.00	steel poles	0.40		1
3	Edge Moor	Brandywine	138.00	138.00	steel poles	2.52		1
4	Edge Moor	Christiana	138.00	138.00	steel towers	2.56	0.15	1
5	Keeney	Churchmans	138.00	138.00	steel poles	6.05		1
6	Churchmans	Basin Road	138.00	138.00	steel poles	0.93	2.50	1
7	Mt Pleasant	Townsend	138.00	138.00	steel poles	11.27		1
8	Keeney	Glasgow	138.00	138.00	steel poles	3.33		1
9	New Castle	Hares Corner	138.00	138.00	steel poles	3.68		1
10	Hares corner	Red Lion	138.00	138.00	wood poles	4.48	0.68	1
11	Christiana	New Castle	138.00	138.00	steel towers	0.75	3.46	1
12	Basin Road	Bear	138.00	138.00	wood poles	4.69		1
13	Keeney	Sunset Lake	138.00	138.00	wood poles	2.27		1
14	Red Lion	Reybold	138.00	138.00	steel poles	0.14	1.11	1
15	Glasgow	Cecil	138.00	138.00	steel poles	5.24		1
16	Basin Road	Kiamensi	138.00	138.00	steel towers	3.20		1
17	Basin Road	New Castle	138.00	138.00	steel towers	0.11	2.94	1
18	Keeney	Chapel Street	138.00	138.00	steel poles	1.27	2.82	1
19	Harmony	Chapel Street	138.00	138.00	steel poles	3.32		1
20	Keeney EHV	Keeney 138	138.00	138.00	steel poles	0.25		1
21	Carrcroft	Talleyville	138.00	138.00	wood poles	3.56		1
22	Edgemoor	Carrcroft	138.00	138.00	steel towers	0.84	2.81	1
23	Motiva	Reybold	138.00	138.00	wood poles	0.08		1
24	Carrcroft	West Wilmington	138.00	138.00	steel towers	4.33		1
25	West Wilmington	Silverbrook	138.00	138.00	steel poles	1.97		1
26	Harmony	Kiamensi	138.00	138.00	steel poles	4.23		1
27	Kiamensi	Silverbrook	138.00	138.00	steel towers	2.70	1.00	1
28	Brandywine	Carrcroft	138.00	138.00	steel towers	1.36	2.87	1
29	Red Lion	Bloom Energy	138.00	138.00	steel poles	0.44		1
30	Cedar Creek	Clayton	138.00	138.00	wood poles	9.23		1
31	Townsend	Church	138.00	138.00	steel poles	12.32		1
32	Kiamensi	Milltown	138.00	138.00	wood poles	1.40	1.31	1
33	Milltown	Valley Road	138.00	138.00	wood poles	4.60		1
34	Valley Road	Hockessin	138.00	138.00	wood poles	1.78		1
35	Kiamensi	Hockessin	138.00	138.00	wood poles	6.26		1
36					TOTAL	2,658.51	345.36	310

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Reybold	Lums Pond	138.00	138.00	wood poles	8.22		1
2	Lums pond	Mt Pleasant	138.00	138.00	wood poles	9.74		1
3	Bear	Sunset Lake	138.00	138.00	wood poles	5.31		1
4	Glasgow	Mt Pleasant	138.00	138.00	steel poles	11.10		1
5	Carville	Wye Mills	138.00	138.00	steel poles	0.12	7.93	1
6	Piney Grove	Wattsville	138.00	138.00	steel poles	0.71	30.19	1
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
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27								
28								
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35								
36					TOTAL	2,658.51	345.36	310

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	842,230	23,316,490	24,158,720					1
								2
	15,382,105	212,933,957	228,316,062					3
								4
	11,248,373	394,040,986	405,289,359					5
								6
	7,548,675	249,061,925	256,610,600					7
								8
	9,713	23,920,198	23,929,911					9
								10
								11
								12
	184,167	1,752,004	1,936,171					13
	181,238	952,788	1,134,026					14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
					7,497,935	202,221	7,700,156	35
	35,396,501	905,978,348	941,374,849		7,497,935	202,221	7,700,156	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2505 AACSR								1
2493 ACAR								2
2493 ACAR								3
1590 ACSR								4
1590 ACSR								5
1590 ACSR								6
1590 ACSR								7
1590 ACSR								8
1590 ACSR								9
1590 ACSR								10
1590 ACSR								11
1590 ACSR								12
1590 ACSR								13
795 ACSR								14
1590 ACSR								15
1590 ACSR								16
1590 ACSR								17
795 ACSR								18
1590 ACSR								19
1590 ACSR								20
1590 ACSR								21
1590 ACSR								22
1590 ACSR								23
1590 ACSR								24
1590 ACSR								25
1590 ACSR bundled								26
1590 ACSR								27
1590 ACSR								28
1590 ACSR								29
336.4 ACSR								30
477 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
954 ACSR								35
	35,396,501	905,978,348	941,374,849		7,497,935	202,221	7,700,156	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR								1
1590 ACSR								2
996.2 ACSR								3
954 ACSR								4
954 ACSR								5
1590 ACSR								6
1590 ACSR								7
954 ACSR								8
1590 ACSR								9
954 ACSR								10
966.2 ACSR								11
954 ACSR								12
954 ACSR								13
954 ACSS								14
1590 ACSR								15
2000 KCMIL CU								16
954 ACSR								17
954 ACSR								18
477 ACSR								19
556.5 ACSS								20
954 ACSR								21
954 ACSR								22
954 ACSR								23
954 ACSR								24
954 ACSR								25
954 ACSR								26
954 ACSR								27
477 ACSR								28
954 ACSR								29
1590 ACSR								30
954 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
1590 ACSR								35
	35,396,501	905,978,348	941,374,849		7,497,935	202,221	7,700,156	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR								1
954 ACSR								2
954 ACSR								3
954 ACSR								4
1590 ACSR								5
636 ACSR								6
1590 ACSR								7
636 ACSR								8
954 Phoenix								9
954 Phoenix								10
636 ACSR								11
954 ACSR								12
954 ACSR								13
954 ACSR								14
1590 ACSR								15
954 ACSR								16
954 ACSR								17
954 ACSR								18
477 ACSS/TW								19
1590 ACSR								20
477 AA								21
954 ACSR								22
954 ACSR								23
954 ACSR								24
954 ACSR								25
1590 ACSR								26
954 ACSR								27
954 ACSR								28
954 ACSR								29
954 ACSR								30
636 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
954 ACSR								35
	35,396,501	905,978,348	941,374,849		7,497,935	202,221	7,700,156	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR								1
954 ACSR								2
954 ACSR								3
1590 ACSR								4
1590 ACSR								5
954 ACSR								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
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								27
								28
								29
								30
								31
								32
								33
								34
								35
	35,396,501	905,978,348	941,374,849		7,497,935	202,221	7,700,156	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 35 Column: o

TRANSMISSION LINE AGREEMENTS:

Cost of lines and related operating expenses as shown are respondent's share only and are to the appropriate regulatory accounts as prescribed by the Uniform System of Accounts.

1. Owners in common of the "Salem-New Freedom (South)", "Hope Creek-Red Lion Line (NJ Section)", "Deans-Branchburg", the section of "Salem-Deans" north of "New Freedom", and "Hope Creek-Salem" LDV Transmission Lines are as follows:

	Percentage
Public Service Electric & Gas	42.55
Atlantic City Electric	13.90
Delmarva Power & Light	1.00
PECO Energy Co	42.55
Total	100.00

2. Owners in common of the reconstructed river crossing portion of the Hope Creek-Red Lion line are as follows:

	Percentage
Public Service Electric & Gas	42.55
Atlantic City Electric	7.45
Delmarva Power & Light	7.45
PECO Energy Co	42.55
Total	100.00

LDV (500KV) Summary:

Delmarva holds a 7.45% share in the Lower DE Valley (LDV) Transmission Project. (Its over investment results in net rental income.)

Schedule Page: 422.1 Line No.: 33 Column: f

Includes 3.15 miles of steel poles as well.

Schedule Page: 422.2 Line No.: 14 Column: i

Includes 954 ACSR as well.

Schedule Page: 422.2 Line No.: 16 Column: f

Includes 0.14 miles of UG as well.

Schedule Page: 422.2 Line No.: 16 Column: i

Includes 1949 ACSS as well.

Schedule Page: 422.2 Line No.: 31 Column: f

Includes 2.81 miles of UG as well.

Schedule Page: 422.2 Line No.: 31 Column: i

Includes KCMIL AL as well.

Schedule Page: 422.3 Line No.: 15 Column: i

Includes 768.2 ACSS as well.

Schedule Page: 422.3 Line No.: 28 Column: f

Includes 1.24 miles of UG as well.

Schedule Page: 422.3 Line No.: 28 Column: i

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Delmarva Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/02/2019	2018/Q4
FOOTNOTE DATA			

Includes KCMIL AL as well.

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Piney Groove	Wattsville	31.00	Steel Poles	11.00	2	2
2							
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38							
39							
40							
41							
42							
43							
44	TOTAL		31.00		11.00	2	2

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
 3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
954 ACSR			230		9,724,135	3,854,386		13,578,521	1
									2
									3
									4
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									43
					9,724,135	3,854,386		13,578,521	44

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Andora-Cecil, MD	Distribution-Unattd	34.00	4.00	
2	Appleton-Cecil, MD	Distribution-Unattd	34.00	4.00	
3	Basin Road Sub - New Castle, DE	Transmission-Unattd	138.00	69.00	
4	Basin Road - New Castle, DE	Distribution-Unattd	138.00	12.00	
5	Basin Road - New Castle, DE	Distribution-Unattd	69.00	12.00	
6	Bear Sub - New Castle, DE	Distribution-Unattd	138.00	12.00	
7	Bear Sub - New Castle, DE	Distribution-Unattd	138.00	34.50	
8	Bethany Sub - Bethany, DE	Distribution-Unattd	138.00	12.00	
9	Bethany Sub-Bethany, DE	Transmission-Unattd	138.00	69.00	
10	Bethany Sub-Bethany, DE	Distribution-Unattd	69.00	12.50	
11	Bishop - Bishopville, MD	Distribution-Unattd	138.00	24.94	
12	Blue Ball Rd Sub - Elkton, MD	Distribution-Unattd	34.00	4.00	
13	Bohemia-Cecil, MD	Distribution-Unattd	34.00	4.00	
14	Bozman-Bozman, MD	Distribution-Unattd	69.00	25.00	
15	Brandywine Sub-Wilm, DE	Distribution-Unattd	138.00	12.00	
16	Bridgeville Sub-Bridgeville, DE	Distribution-Unattd	69.00	12.50	
17	Brookside Sub-Pencader, DE	Distribution-Unattd	34.50	12.00	
18	Calvert-Cecil, MD	Distribution-Unattd	34.00	4.00	
19	Cambridge, MD	Distribution-Unattd	69.00	12.50	
20	Carrcroft Sub-Brandywine Hd, DE	Transmission-Unattd	138.00	69.00	
21	Carrcroft Sub-Brandywine Hd, DE	Distribution-Unattd	138.00	34.50	
22	Cathers-Cecil, MD	Distribution-Unattd	34.00	4.00	
23	Cayots-Cecil, MD	Distribution-Unattd	34.00	4.00	
24	Cecil-Cecil, MD	Distribution-Unattd	138.00	34.00	
25	Cecil-Cecil, MD	Distribution-Unattd	230.00	34.00	
26	Cecil-Cecil, MD	Transmission-Unattd	230.00	138.00	
27	Cecil Unit-Cecil, MD	Distribution-Unattd	34.00	4.00	
28	Cedar Creek Sub-New Castle, DE	Transmission-Unattd	230.00	138.00	
29	Cedar Creek Sub-New Castle, DE	Distribution-Unattd	138.00	25.00	
30	Cedar Neck, DE	Distribution-Unattd	69.00	12.00	
31	Centreville, MD	Distribution-Unattd	69.00	12.50	
32	Chapel St, Newark, DE	Distribution-Unattd	138.00	34.50	
33	Chapel St Sub-Newark, DE	Distribution-Unattd	34.50	12.00	
34	Charles-Cecil, MD	Distribution-Unattd	34.00	4.00	
35	Chesapeake City-Cecil, MD	Distribution-Unattd	34.00	4.00	
36	Chestertown, MD	Distribution-Unattd	69.00	25.00	
37	Chestnut Run Sub-Christiana Hd, DE	Distribution-Unattd	34.50	12.00	
38	Cheswold Sub-Cheswold, DE	Distribution-Unattd	138.00	25.00	
39	Cheswold Sub-Cheswold, DE	Transmission-Unattd	138.00	69.00	
40	Christiana Sub-Wilm DE	Distribution-Unattd	138.00	12.00	

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Church-Millington, MD	Transmission-Unattd	138.00	69.00	
2	Church-Millington, MD	Distribution-Unattd	69.00	25.00	
3	Churchmans - New Castle, DE	Distribution-Unattd	138.00	12.00	
4	Claymont Sub-Brandywine Hd, DE	Transmission-Unattd	230.00	69.00	
5	Clayton Sub-Clayton, DE	Distribution-Unattd	25.00	4.20	
6	Clayton Sub-Clayton, DE	Distribution-Unattd	138.00	25.00	
7	Colora-Cecil, MD	Distribution-Unattd	230.00	34.00	
8	Cool Spring Sub - Milton, DE	Transmission-Unattd	230.00	69.00	
9	Cowlane-Cecil, MD	Distribution-Unattd	34.00	4.00	
10	Crisfield-Crisfield, MD	Distribution-Unattd	69.00	25.00	
11	Crisfield-Crisfield, MD	Distribution-Unattd	69.00	12.50	
12	Crisfield-Crisfield, MD	Distribution-Unattd	25.00	4.20	
13	Culver-Ocean City, MD	Distribution-Unattd	69.00	25.00	
14	Darley Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	12.00	
15	Darley Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	34.50	
16	Darlington-Harford, MD	Distribution-Unattd	34.00	4.00	
17	Dublin-Harford, MD	Distribution-Unattd	34.00	4.00	
18	East New Market, MD	Distribution-Unattd	69.00	12.50	
19	Easton-Easton, MD	Distribution-Unattd	69.00		
20	Easton-Easton, MD	Transmission-Unattd	138.00	69.00	
21	Easton-Easton, MD	Distribution-Unattd			
22	Edge Moor - Brandywine , DE	Distribution-Unattd	138.00	12.00	
23	Edge Moor - Brandywine, DE	Transmission-Unattd	138.00	69.00	
24	Edge Moor - Brandywine, DE	Transmission-Unattd	230.00	138.00	
25	Edge Moor - Brandywine, DE	Distribution-Unattd	69.00	12.00	
26	Elkneck-Cecil, MD	Distribution-Unattd	34.00	4.00	
27	Elkton-Cecil, MD	Distribution-Unattd	34.00	4.00	
28	Faulk Rd Sub-Brandywine Hd, DE	Distribution-Unattd	34.50	12.00	
29	Five Points, DE	Distribution-Unattd	69.00	12.50	
30	Felton	Distribution-Unattd	138.00	25.00	
31	Foundry-Cecil, MD	Distribution-Unattd	34.00	4.00	
32	Frankford, DE	Distribution-Unattd	138.00	25.00	
33	Fruitland, MD	Distribution-Unattd	69.00	25.00	
34	Gallion-Harford, MD	Distribution-Unattd	34.00	4.00	
35	Gilpin-Cecil, MD	Distribution-Unattd	34.00	4.00	
36	Glasgow - New Castle, DE	Distribution-Unattd	34.00	12.00	
37	Glasgow - New Castle, DE	Distribution-Unattd	138.00	12.00	
38	Glasgow Sub-Pencader Hd, DE	Distribution-Unattd	138.00	34.50	
39	Glen-Cecil, MD	Distribution-Unattd	34.00	4.00	
40	Gloria St-St. Michaels, MD	Distribution-Unattd	12.50	4.20	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Grace Street-St. Michaels, MD	Distribution-Unattd	69.00	12.50	
2	Grasonville, MD	Distribution-Unattd	69.00	25.00	
3	Greenbank, Cecil, MD	Distribution-Unattd	34.00	4.00	
4	Hances-Cecil, MD	Distribution-Unattd	34.00	4.00	
5	Harbeson Sub-Harbeson, DE	Distribution-Unattd	69.00	25.00	
6	Hares Corner - New Castle, DE	Distribution-Unattd	138.00	12.00	
7	Harford-Harford, MD	Distribution-Unattd	34.00	4.00	
8	Harmony Sub-White Clay, DE	Transmission-Unattd	230.00	138.00	
9	Harmony Sub-White Clay, DE	Distribution-Unattd	138.00	34.50	
10	Harmony Sub-White Clay, DE	Distribution-Unattd	138.00	12.00	
11	Harrington Sub-Harrington, DE	Distribution-Unattd	69.00	25.00	
12	Harris-Cecil, MD	Distribution-Unattd	34.00	4.00	
13	Hebron-Hebron, MD	Distribution-Unattd	69.00	24.94	
14	Hillsboro-Hillsboro, MD	Distribution-Unattd	138.00	25.00	
15	Hockessin Sub-Mill Cr Hd, DE	Distribution-Unattd	138.00	12.00	
16	Indian River Sub-Millsboro, DE	Transmission-Unattd	230.00	138.00	
17	Indian River Sub-Millsboro, DE	Transmission-Unattd	138.00	69.00	
18	Irishtown-Cecil, MD	Distribution-Unattd	34.00	4.00	
19	Jacktown-Cambridge, MD	Distribution-Unattd	69.00	12.50	
20	Keeney EHV-Pencader Hd, DE	Transmission-Unattd	500.00	230.00	
21	Keeney EHV, DE	Transmission-Unattd	230.00	138.00	
22	Keeney EHV, DE	Distribution-Unattd	230.00	34.50	
23	Keeney 138kV, DE	Distribution-Unattd	138.00	12.00	
24	Kenney-Snow Hill, MD	Distribution-Unattd	69.00	25.00	
25	Kent Sub-Dover, DE	Distribution-Unattd	69.00	25.00	
26	Kiamensi Sub-Christiana Rd, DE	Transmission-Unattd	138.00	69.00	
27	Kiamensi Sub-Christiana Rd, DE	Distribution-Unattd	138.00	34.50	
28	Kilby-Cecil, MD	Distribution-Unattd	34.00	4.00	
29	Kings Creek-Princess Anne, MD	Transmission-Unattd	138.00	69.00	
30	Kings Creek-Princess Anne, MD	Distribution-Unattd	138.00	25.00	
31	Laurel Sub-Laurel Sub, DE	Distribution-Unattd	69.00	12.50	
32	Leslie-Cecil, MD	Distribution-Unattd	34.00	4.00	
33	Liberty Grove-Cecil, MD	Distribution-Unattd	34.00	4.00	
34	Little Falls, DE	Distribution-Unattd	34.00	12.00	
35	Loretto-Princess Anne, MD	Transmission-Unattd	138.00	69.00	
36	Lums Pond-New Castle Hd, DE	Distribution-Unattd	138.00	25.00	
37	Lynch-Lynch, MD	Distribution-Unattd	69.00	25.00	
38	Macton-Harford, MD	Distribution-Unattd	34.00	4.00	
39	Maridel-Ocean City, MD	Distribution-Unattd	69.00	12.50	
40	Massey Sub-Galena, MD	Distribution-Unattd	69.00	25.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Mechanics-Cecil, MD	Distribution-Unattd	34.00	4.00	
2	Mermaid Sub-New Castle Hd, DE	Distribution-Unattd	34.50	12.00	
3	Mermaid Sub-New Castle Hd, DE	Distribution-Unattd	138.00	12.00	
4	Middle-Cecil, MD	Distribution-Unattd	34.00	4.00	
5	Midway Sub-Rehoboth, DE	Distribution-Unattd	69.00	12.50	
6	Milford Sub-Milford, DE	Distribution-Unattd	138.00	25.00	
7	Milford Sub-Milford, DE	Transmission-Unattd	230.00	138.00	
8	Milford Crossroads-Mill Cr Rd, DE	Distribution-Unattd	34.00	12.00	
9	Millsboro Sub-Millsboro, DE	Distribution-Unattd	69.00	25.00	
10	Milltown Rd Sub-MilCrRd, DE	Distribution-Unattd	34.50	12.00	
11	Milltown Rd Sub-MilCrRd, DE	Distribution-Unattd	138.00	12.00	
12	Montchanin Sub-Brandywine Hd, DE	Distribution-Unattd	34.50	12.00	
13	Mt. Hermon-Salisbury, MD	Distribution-Unattd	69.00	25.00	
14	Mt. Pleasant-New Castle Hd, DE	Distribution-Unattd	138.00	25.00	
15	Naamans Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	12.00	
16	Nelson Sub-Delmar, DE	Transmission-Unattd	138.00	69.00	
17	Nelson Sub-Delmar, DE	Distribution-Unattd	138.00	12.50	
18	Nesbitt-Cecil, MD	Distribution-Unattd	34.00	4.00	
19	New Castle Sub-New Castle Hd, DE	Distribution-Unattd	69.00	12.00	
20	Normira-Cecil, MD	Distribution-Unattd	34.00	4.00	
21	Northeast-Cecil, MD	Distribution-Unattd	34.00	4.00	
22	N Salisbury, MD	Distribution-Unattd	69.00	25.00	
23	N Seaford Sub-Seaford, DE	Transmission-Unattd	138.00	69.00	
24	N Seaford Sub-Seaford, DE	Distribution-Unattd	69.00	12.50	
25	Oak Hall-Oak Hall, VA	Transmission-Unattd	138.00	69.00	
26	Ocean Bay-Ocean City, MD	Distribution-Unattd	138.00	12.50	
27	Ocean Bay-Ocean City, MD	Transmission-Unattd	138.00	69.00	
28	Ocean City, MD	Distribution-Unattd	69.00	12.50	
29	Ocean City 138 St., MD	Distribution-Unattd	138.00	12.50	
30	Ocean City 138 St., MD	Transmission-Unattd	138.00	16.00	
31	Otsego-Cecil, MD	Distribution-Unattd	34.00	4.00	
32	Pemberton - Salisbury, MD	Distribution-Unattd	69.00	25.00	
33	Perch - Cecil, MD	Distribution-Unattd	34.00	4.00	
34	Piney Grove-Salisbury, MD	Transmission-Unattd	138.00	69.00	
35	Piney Grove-Salisbury, MD	Transmission-Unattd	230.00	138.00	
36	Pocomoke-Pocomoke, MD	Distribution-Unattd	138.00	12.50	
37	Point Breeze Sub-Brandywine Rd, DE	Distribution-Unattd	34.50	12.00	
38	Porter's Bridge-Cecil, MD	Distribution-Unattd	34.00	4.00	
39	Preston-Preston	Distribution-Unattd	69.00	12.50	
40	Price Sub - Price, MD	Distribution-Unattd	69.00	25.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Prince-Cecil, MD	Distribution-Unattd	34.00	4.00	
2	Red Lion-New Castle, DE	Transmission-Unattd	525.00	230.00	
3	Red Lion-New Castle, DE	Distribution-Unattd	138.00	25.00	
4	Red Lion Sub-Pencader Hd, DE	Transmission-Unattd	230.00	138.00	
5	Rehoboth Sub-Rehoboth, DE	Transmission-Unattd	138.00	69.00	
6	Rehoboth Sub-Rehoboth, DE	Distribution-Unattd	69.00	12.50	
7	Reybold Sub-Red Lion Hd, DE	Transmission-Unattd	138.00	69.00	
8	Reybold Sub-Red Lion Hd, DE	Distribution-Unattd	138.00	12.00	
9	Rising Sun-Cecil, MD	Distribution-Unattd	34.00	4.00	
10	Sharptown-Sharptown, MD	Distribution-Unattd	69.00	12.50	
11	Silverbrook Sub, DE	Distribution-Unattd	138.00	34.50	
12	Silverside, DE	Distribution-Unattd	12.00	4.20	
13	Silverside Rd Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	12.00	
14	Silverside Rd Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	34.50	
15	S Harrington Sub-Harrington, DE	Transmission-Unattd	138.00	69.00	
16	Steele-Denton, MD	Transmission-Unattd	230.00	138.00	
17	Steele-Denton, MD	Distribution-Unattd	138.00	25.00	
18	Stevensville, MD	Distribution-Unattd	69.00	25.00	
19	Stockton-Stockton, MD	Distribution-Unattd	69.00	4.20	
20	Sunset Lake Sub-Pencader Hd, DE	Distribution-Unattd	138.00	12.00	
21	Sussex Sub-Georgetown, DE	Distribution-Unattd	69.00	12.50	
22	Talleyville Sub-Brandywine Hd, DE	Distribution-Unattd	34.50	12.00	
23	Talleyville, DE	Distribution-Unattd	138.00	12.00	
24	Telegraph-Cecil, MD	Distribution-Unattd	34.00	25.00	
25	Theodore-Cecil, MD	Distribution-Unattd	34.00	4.00	
26	Todd-Hurlock, MD	Distribution-Unattd	69.00	25.00	
27	Todd-Hurlock, MD	Distribution-Unattd	69.00	12.00	
28	Todd-Hurlock, MD	Distribution-Unattd	69.00	25.00	
29	Townsend Sub-New Castle Hd, DE	Distribution-Unattd	138.00	25.00	
30	Trappe-Trappe, MD	Distribution-Unattd	69.00	12.50	
31	Triumph-Cecil, MD	Distribution-Unattd	34.00	4.00	
32	Vienna-Vienna, MD	Transmission-Unattd	138.00	69.00	
33	Vienna-Vienna, MD-Local	Distribution-Unattd	69.00	12.50	
34	Vienna-Vienna, MD	Transmission-Unattd	230.00	138.00	
35	Walnut-Cecil, MD	Distribution-Unattd	34.00	4.00	
36	Washington College - Chestertown, MD	Distribution-Unattd	25.00	4.20	
37	Wattsville-Wattsville, VA	Distribution-Unattd	69.00		
38	Wattsville-Wattsville, VA	Transmission-Unattd	138.00	69.00	
39	West Sub-Christiana Hd, DE	Distribution-Unattd	69.00	34.50	
40	West Sub-Christiana Hd, DE	Distribution-Unattd	69.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	West Cambridge, MD	Distribution-Unattd	69.00	12.00	
2	West Wilmington-Wilm, DE	Distribution-Unattd	138.00	12.00	
3	Whiteford-Harford, MD	Distribution-Unattd	34.00	4.00	
4	Woodlawn-Cecil, MD	Distribution-Unattd	34.00	4.00	
5	Worcester-Berlin, MD	Distribution-Unattd	69.00	25.00	
6	Worcester-Berlin, MD	Transmission-Unattd	138.00	69.00	
7	Wye Mills, Wye Mills, MD	Transmission-Unattd	138.00	69.00	
8	Wye Mills, Wye Mills, MD	Distribution-Unattd	69.00	25.00	
9					
10	Spare Transformer		34.00	12.00	
11	Spare Transformer		138.00	36.20	
12	Spare Transformer		34.50	4.40	
13	Spare Transformer		138.00	12.47	
14	Spare Transformer		138.00	12.47	
15	Spare Transformer		34.50	4.36	
16	Spare Transformer		138.00	24.94	
17	Spare Transformer		230.00	16.00	
18	Spare Transformer		230.00	34.50	
19	Spare Transformer		138.00	36.20	
20	Spare Transformer		34.00	12.00	
21	Spare Transformer		138.00	12.47	
22	Spare Transformer		138.00	16.00	
23	Spare Transformer		69.00	24.94	
24	Spare Transformer		34.40	4.36	
25	Spare Transformer		69.00	12.47	
26	Spare Transformer		138.00	24.94	
27	Spare Transformer		138.00	12.00	
28	Spare Transformer		138.00	25.00	
29	Spare Transformer		69.00	34.50	
30	Spare Transformer		138.00	69.00	
31	Spare Transformer		230.00	138.00	
32	Spare Transformer		500.00	230.00	
33	Spare Transformer		500.00	230.00	
34	Spare Transformer		230.00	138.00	
35	Spare Transformer		230.00	138.00	
36	Spare Transformer		230.00	69.00	
37	Spare Transformer		138.00	69.00	
38					
39					
40					

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Mobile D1		138.00	25.00	
2	Mobile D2		69.00	25.00	
3	Mobile D3		34.00	12.00	
4	Mobile D4		138.00	25.00	
5	Mobile D5		69.00	25.00	
6	Mobile D6		138.00	25.00	
7	Mobile D7		69.00	25.00	
8	Mobile D8		69.00	12.00	
9	Mobile D9		138.00	12.00	
10	Mobile D10		138.00	25.00	
11	Mobile D11		138.00	25.00	
12					
13	New Substations - 2017				
14	Crest, Cecil Co., MD	Dist-Unattd	230.00	34.00	
15	Crothers Road, Cecil Co., MD	Dist-Unattd	34.00	4.00	
16					
17	New Substations - 2018				
18	Carville - Centreville, MD	Dist-Unattd	138.00	24.94	
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
4	1					1
6	2					2
84	1					3
22	1					4
22	1		69kV capacitor bank	1	24	5
112	2					6
84	1					7
40	1					8
224	1		138kv capacitor bank	1	29	9
20	1		69kV capacitor bank	2	34	10
38	1					11
4	1					12
8	2					13
56	2					14
168	2		12kv capacitor bank	2	14	15
37	4		69kV capacitor bank	2	30	16
43	2					17
4	1					18
68	2		69kv capacitor bank	1	12	19
100	1					20
84	1		34kv capacitor bank	1	9	21
8	2					22
7	2					23
112	1		34kv capacitor bank	2	29	24
90	1					25
336	1					26
8	2					27
336	1		230kV reactor	1	40	28
28	1					29
75	2					30
32	4					31
84	1		138kv capacitor bank	2	29	32
8	1		34kv capacitor bank	1	9	33
6	2					34
4	1					35
45	2		69kv capacitor bank	1	8	36
42	2		12kv capacitor bank	2	6	37
25	1		138kv capacitor bank	1	19	38
225	1					39
168	3		12kv capacitor bank	6	36	40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
325	2		138kv capacitor bank	2	22	1
63	2		25kv capacitor bank	1	4	2
112	2					3
312	2		69kv capacitor bank	1	13	4
4	1		25kv capacitor bank	2	10	5
50	2					6
220	2		69/34kv capacitor ba	3	28	7
336	1					8
4	1					9
28	1					10
13	1		69kV capacitor bank	2	14	11
3	1					12
22	1					13
74	2		12kv capacitor bank	1	5	14
50	1		69kV cap bank	2	31	15
4	1					16
8	2					17
6	1		69kV capacitor bank	2	17	18
			69kV capacitor bank	1	10	19
168	1					20
			69kV reactor	2	30	21
62	1					22
224	2					23
336	1					24
206	3					25
5	1					26
17	3					27
45	2		12kv capacitor bank	1	3	28
45	2					29
			138kV capacitor bank	1	34	30
4	1					31
28	1					32
67	2		25kv capacitor bank	1	5	33
8	2					34
4	1					35
8	1					36
28	1					37
84	1		34kV capacitor bank	1	9	38
8	2					39
3	6					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
32	6					1
50	2		69kv capacitor bank	2	22	2
4	1					3
4	1					4
63	2		69kv capacitor bank	1	20	5
93	2					6
8	2					7
896	2		138kv capacitor bank	1	36	8
134	2					9
112	2		12kv capacitor bank	1	5	10
50	2		69/25kv Capacitor	2	26	11
4	1					12
56	2					13
53	2					14
112	2					15
1344	3		SVC/cap 230 kv bank	2	200	16
224	1					17
4	1					18
38	1					19
2000	2					20
448	1					21
84	1					22
67	2		138kv capacitor bank	1	36	23
25	2					24
47	2					25
112	1		138kv capacitor bank	1	30	26
106	2		34kv capacitor bank	1	9	27
4	2					28
224	2		69kV capacitor bank	1	11	29
50	2					30
40	2		69kV capacitor bank	1	20	31
5	1					32
8	2					33
20	1					34
100	2		69kV capacitor bank	2	29	35
83	2					36
28	1					37
8	2					38
45	2		69kv capacitor bank	2	28	39
28	1		69kv capacitor bank	1	8	40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
3	1					1
20	1					2
56	1					3
4	1					4
60	2					5
50	1					6
336	1					7
45	2		12kv capacitor bank	1	3	8
66	2		69kv capacitor bk	2	19	9
			12 kv capacitor bank	2	5	10
112	2					11
45	2					12
84	2					13
79	2		138/25kv capacitor b	2	27	14
75	2					15
100	1		SVC	1	150	16
50	2		69kv capacitor bank	1	20	17
4	1					18
123	3		12kv capacitor bank	2	12	19
4	1					20
4	1					21
84	2		69kv capacitor bank	1	20	22
187	2		138kV capacitor bank	2	19	23
38	1		69kV capacitor bank	1	13	24
224	2		69kv capacitor bank	1	11	25
80	2					26
200	1					27
84	2					28
75	2					29
75	1		SVC	1	75	30
8	2					31
33	1					32
5	1					33
225	1		69kv capacitor bank	1	20	34
300	1					35
40	2					36
40	2					37
4	1					38
7	1					39
28	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
4	1					1
1569	6					2
28	1					3
672	2					4
224	1		69kv capacitor	2	31	5
75	2		12kv capacitor	1	3	6
112	1					7
74	2		12kv capacitor	1	3	8
7	2					9
7	1					10
184	2		34kv capacitor	1	9	11
7	3					12
67	2		12kv capacitor	3	13	13
56	1					14
112	1		69kv capacitor bank	1	13	15
892	3		138kv capacitor	2	38	16
38	1		25kv capacitor	1	5	17
70	2					18
5	3					19
103	3		12kv capacitor bk	2	11	20
75	2		69kv capacitor bank	1	10	21
45	2					22
56	1		12kv capacitor bank	2	5	23
8	1					24
4	1					25
28	1		69kv cap bank	1	13	26
11	3					27
28	1		25kv cap bank	1	5	28
56	1	1	138kv capacitor bank	1	22	29
22	1					30
4	1					31
224	2		69/138kv cap bank	2	40	32
3	1					33
448	1					34
4	1					35
2	1					36
			69kv cap bank	2	22	37
225	1					38
112	2		69kv capacitor bank	1	20	39
112	2		12kv capacitor bank	2	12	40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
22	1		69kv capacitor bank	1	11	1
168	2		12kv capacitor bank	2	6	2
4	1					3
4	1					4
66	2		69kv capacitor bank	1	20	5
224	1					6
448	2		69/138kv cap.	4	50	7
56	2		25kV cap bank	1	2	8
						9
22		1				10
84		1				11
4		1				12
56		1				13
84		1				14
4		1				15
28		1				16
150		1				17
112		1				18
84		1				19
20		1				20
56		1				21
150		1				22
56		1				23
2		1				24
56		1				25
38		1				26
38		1				27
56		1				28
56		1				29
112		1				30
336		1				31
243		1				32
333		1				33
448		1				34
336		1				35
336		1				36
225		1				37
						38
						39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
25		1				1
12		1				2
20		1				3
12		1				4
40		1				5
28		1				6
30		1				7
27		1				8
21		1				9
30		1				10
30		1				11
						12
						13
224	2					14
4	1					15
						16
						17
75	2					18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

	Voltage			Capacity in (MVA)	Numbers of Transformers in Service	Transformers Spare	Conversion Number	Apparatus Total Capacity (MVAR)
	Primary	Secondary	Tertiary					
Transmission	-	-	-	15,152	63	8	72	1,554
Distribution	-	-	-	7,540	279	20	63	247
Total	-	-	-	22,692	342	28	135	1,801

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	PHI Service Company (PHISCO)			
3	Centralized Support Services	PHISCO	Various	135,965,026
4				
5	Exelon Business Services Company (EBSC)			
6	Centralized Support Services	EBSC	Various	82,073,990
7				
8	Atlantic City Electric Co (ACE)			
9	Materials	ACE	154	3,248,690
10	Facility Services	ACE	921	3,151
11				
12	Atlantic Southern Properties (ASP)			
13	Facility Services	ASP	921	1,248
14				
15	Constellation Power Source Gen (CPSG)			
16	Mechanical and Electrical Industrial Services	CPSG	Various	15,139
17				
18	Exelon PowerLabs, LLC (EPL)			
19	Calibration and Engineering Services	EPL	921	7,051
20	Non-power Goods or Services Provided for Affiliate			
21	Atlantic City Electric Co (ACE)			
22	Materials	ACE	154	3,422,344
23	Mutual Assistance - Storm Costs	ACE	456	775,798
24	Extra-High Voltage (EHV) Transmission Agreement	ACE	456	78,288
25	Maintenance Services	ACE	415	56,570
26	Facility Services	ACE	456	17,872
27	Regulatory Services	ACE	415	1,035
28				
29	Baltimore Gas & Electric Co. (BGE)			
30	Mutual Assistance Revenue - Storm Costs	BGE	456	7,071
31	Extra-High Voltage (EHV) Transmission Agreement	BGE	456	234,864
32				
33	Commonwealth Edison Company (ComEd)			
34	Mutual Assistance - Storm Costs	ComEd	456	620,295
35				
36	Exelon Business Services Company (EBSC)			
37	Building Lease (use of building space)	EBSC	456	637,183
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2	PECO Energy Company (PECO)			

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Information Technology Services	PECO	Various	61,031
4	Extra-High Voltage (EHV) Transmission Agreement	PECO	571	36,492
5				
6	Potomac Electric Power Company (Pepco)			
7	Lease of Office Space	Pepco	184	1,837
8	Shop Department Fabrication Services	Pepco	Various	496,440
9	Field Operations Services	Pepco	921	19,439
10	Materials	Pepco	154	431,109
11				
12	Baltimore Gas & Electric Co. (BGE)			
13	Mutual Assistance - Storm Costs	BGE	874	5,489
14	Regulatory Services	BGE	921	81,067
15	Information Technology Services	BGE	Various	30,168
16	Field Operations Services	BGE	921	47,928
17	Legal Services	BGE	921	7,652
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22	Potomac Electric Power Company (PEPCO)			
23	Extra-High Voltage (EHV) Transmission Agreement	PEPCO	456	234,864
24	Materials	PEPCO	154	89,512
25	Lease of Office Space	PEPCO	456	1,594
26				
27	PECO Energy Company (PECO)			
28	Mutual Assistance -Storm Costs	PECO	456	89,236
29	Extra-High Voltage (EHV) Transmission Agreement	PECO	456	287,052
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2	Commonwealth Edison Company (ComEd)			
3	Information Technology Services	ComEd	Various	143,250
4				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				
3				
4				
5				
6				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				
3				
4				
5				
6				
7				
8				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
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32				
33				
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36				
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38				
39				
40				
41				
42				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column: a
PHI Service Company (PHISCO) Overview

Services provided by PHISCO are provided under a Service Agreement with Delmarva Power & Light Company (DPL). Charges are provided by either direct charging of costs or are based on an allocation. The Service Agreement provides specific guidelines on the allocation methods used to charge these costs to the various PHI affiliates. Information on the Service Company allocation methods are explained in detail under Schedule XXI, Methods of Allocations, in the FERC Form 60 filed for PHISCO.

PHISCO provides a variety of services which include customer services, support services, financial services, human resources, legal services, information technology, governmental affairs, communication services, regulatory services, regulated gas and electric (transmission and distribution services), executive management, and supply services.

The services provided by the regulated gas and electric area include: system operations services; meter maintenance and testing; power procurement and energy planning; and other delivery services, including delivery senior management, asset management, engineering standards, interconnection planning and arrangements, distribution and transmission planning, engineering services for distribution, substation and transmission, system protection, project and construction management, electric maintenance, administrative support, process improvement, and performance analysis.

Schedule Page: 429 Line No.: 3 Column: c

PHISCO Centralized Support
Services to DPL

FERC account	Amount
107	22,798,058
108	1,904,199
163	771,976
182.3	1,257,480
184	1,996,577
415	8,432
416	90,120
419	(48,940)
426.1	92,536
426.3	6
426.4	81,626
426.5	533,963
430	(17,976)
431	250,017
556	1,179,336
557	1,102,794
560	1,139,212
561.1	(59)
561.2	2,710
561.3	(26)
561.5	108,769
566	1,815,456
568	32,511
569	2,402
569.2	9,783
570	119,193
571	323,919
573	5,310

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

580	519,318
581	125,332
586	921,518
587	310,915
588	1,880,391
590	361,186
592	235,513
593	893,980
594	1,128
597	466,609
598	19,929
813	289,222
878	532,555
893	530,007
902	99,862
903	40,789,128
908	1,547,000
909	416,658
923	48,852,791
924	11,622
925	(88)
928	1,142,635
930.1	25,472
930.2	432,375
935	584
Total	<u>135,965,026</u>

Schedule Page: 429 Line No.: 5 Column: a

Exelon Business Services Company, LLC (EBSC)
Overview

Services provided by EBSC are provided under a General Service Agreement with DPL. Charges are provided by either direct charging of costs or are based on an allocation. The factors for allocating the costs from EBSC to Exelon affiliates are contained in the General Services Agreement. Information on the EBSC allocation methods are explained in detail under Schedule XXI, Methods of Allocations, in the FERC Form 60 filed for EBSC.

EBSC provides a variety of support services, including: financial, human resources IT, communication, legal, governmental and regulatory affairs, executive, security, supply, Exelon Utilities, BSC Operations, real estate, and other.

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

EBSC Centralized
Support Services to DPL

FERC Account	Amount
107	26,797,443
108	55,793

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

163	914,850
416	19,322
426.1	311,547
426.3	50
426.4	96,327
560	2,067,834
566	1,826,944
588	31,160
593	86,945
880	857,391
903	7,899,135
920	1,884
923	40,356,505
924	555,447
925	296
930.1	195,117
Total	<u>82,073,990</u>

Schedule Page: 429 Line No.: 16 Column: c

CPSG Mechanical and
Electrical industrial
Services provided to
DPL:

<u>FERC</u>	<u>Amount</u>
107	\$ 1,954
108	412
184	4,920
571	7,853
Total	<u>15,139</u>

Schedule Page: 429.1 Line No.: 3 Column: c

PECO Information
Technology Services
provided to DPL:

<u>FERC</u>	<u>Amount</u>
107	\$ 7,877
921	53,154
Total	<u>61,031</u>

Schedule Page: 429.1 Line No.: 8 Column: c

Pepco Shops Department
Fabrication Services to
DPL:

<u>FERC</u>	<u>Amount</u>
107	\$ 474,081
108	21,024
923	1,335
Total	<u>\$ 496,440</u>

Schedule Page: 429.1 Line No.: 15 Column: c

BGE Information
Technology Services
provided to DPL:

<u>FERC</u>	<u>Amount</u>
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/02/2019	Year/Period of Report 2018/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

107	\$	8,032
921		<u>22,136</u>
Total		30,168

Schedule Page: 429.2 Line No.: 3 Column: c

ComEd Information
Technology Services
provided to DPL:

<u>FERC</u>	<u>Amount</u>
107	\$ 83,405
921	<u>59,845</u>
Total	\$ 143,250

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