



May 28, 2024

Mr. Andrew S. Johnston  
Executive Secretary  
Public Service Commission of Maryland  
William Donald Schaefer Tower  
6 St. Paul Street, 16<sup>th</sup> Floor  
Baltimore, Maryland 21202

Dear Mr. Johnston

Submitted herewith is Delmarva Power & Light Company's ("DPL") Annual Report to the Public Service Commission of Maryland for the year ended December 31, 2023 as compiled on FERC Form No. 1 pursuant to the Commission's instructions.

We respectfully submit the following reports:

1. One (1) copy of the 2023 DPL Form 1, Annual Report which is the same report as filed with Federal Energy Regulatory Commission (FERC).
2. One (1) copy of the Addendum to 2023 Annual Report/Maryland Jurisdictional Electric Sales Statistics.
3. One (1) copy of the report of Energy Taxes and Property Taxes paid in 2023 to each municipal, county and state agency in Maryland.
4. One (1) copy of the Exelon First Quarter 2024 Form 10-Q (the most current corporate shareholder report).
5. Affidavit on cost allocations and transfer pricing of assets.

If you have any questions, please feel free to contact me at (779) 231-0975.

Sincerely,

Isaac Haertsch, CPA  
Manager, External Financial Reporting, Exelon  
Isaac.Haertsch@exeloncorp.com

Enclosures

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



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

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

<b>Exact Legal Name of Respondent (Company)</b> Delmarva Power & Light Company	<b>Year/Period of Report</b> End of: 2023/ Q4
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FERC FORM NO. 1 (REV. 02-04)

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

**GENERAL INFORMATION**

**Purpose**

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

**Who Must Submit**

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

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

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

## What and Where to Submit

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

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

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:  
Secretary  
Federal Energy Regulatory Commission 888 First Street, NE  
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

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

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

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

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.

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

## When to Submit

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

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

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

## Where to Send Comments on Public Reporting Burden.

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

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

## GENERAL INSTRUCTIONS

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

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## DEFINITIONS

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

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

## EXCERPTS FROM THE LAW

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

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

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

'Person' means an individual or a corporation;

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

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

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

\*Sec. 4. The Commission is hereby authorized and empowered

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

\*Sec. 304.

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

\*Sec. 309.

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

## GENERAL PENALTIES

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

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

FERC FORM NO. 1 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: 2023/ Q4	
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 500 North Wakefield Drive, Newark, Delaware 19702		
05 Name of Contact Person Julie E. Giese	06 Title of Contact Person Director of Accounting	
07 Address of Contact Person (Street, City, State, Zip Code) 500 North Wakefield Drive, Newark, Delaware 19702		
08 Telephone of Contact Person, Including Area Code (302) 429-3225	09 This Report is An Original / A Resubmission (1) An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2023
<b>Annual Corporate Officer Certification</b>		
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 (Mo, Da, Yr) 04/04/2024
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.		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**LIST OF SCHEDULES (Electric Utility)**

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	N/A
16	Electric Plant in Service	204	
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	N/A
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	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	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	

36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	N/A
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
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 (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
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	
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	N/A
64	Hydroelectric Generating Plant Statistics	406	N/A
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	N/A
66.1	Energy Storage Operations (Large Plants)	414	N/A
66.2	Energy Storage Operations (Small Plants)	419	N/A
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	<b>Stockholders' Reports (check appropriate box)</b>		
	Stockholders' Reports Check appropriate box:  Two copies will be submitted No annual report to stockholders is prepared		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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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
500 North Wakefield Drive, Newark, Delaware 19702

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: DE
Date of Incorporation: 1909-04-22
Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.
(a) Name of Receiver or Trustee Holding Property of the Respondent:
(b) Date Receiver took Possession of Respondent Property:
(c) Authority by which the Receivership or Trusteeship was created:
(d) Date when possession by receiver or trustee ceased:

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

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
(2) No

Table with 4 columns: Name of Respondent, This report is, Date of Report, Year/Period of Report. Name of Respondent: Delmarva Power & Light Company. This report is: (1) An Original, (2) A Resubmission. Date of Report: 12/31/2023. Year/Period of Report: End of: 2023/ Q4.

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, 2023, Delmarva Power & Light Company (DPL) is controlled by Pepco Holdings LLC (PHI). PHI 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 (Exelon). For additional information, see the Exelon Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2023.

Table with 4 columns: Name of Respondent, This report is, Date of Report, Year/Period of Report. Name of Respondent: Delmarva Power & Light Company. This report is: (1) An Original, (2) A Resubmission. Date of Report: 12/31/2023. Year/Period of Report: End of: 2023/ Q4.

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.




Table with 5 columns: Line No., Name of Company Controlled (a), Kind of Business (b), Percent Voting Stock Owned (c), Footnote Ref. (d). Rows 1 and 2 are empty.

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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OFFICERS

- 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.
- 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)	Date Started in Period (d)	Date Ended in Period (e)
1	President and Chief Executive Officer	Anthony, J. Tyler	575,000		
2	Sr. Vice President and Chief Operating Officer	Olivier, Tamla A.	417,614		
3	Sr. Vice President, Chief Financial Officer and Treasurer	Barnett, Phillip S.	437,130		
4	Sr. Vice President, Governmental, Regulatory and External Affairs	Oddoye, Rodney	400,608		
5	Vice President and General Counsel	Bancroft, Anne	337,229		
6	Sr. Vice President, Customer Operations	 Bell-Izzard, Morlon	351,220		2023-09-05
7	Corporate Secretary	 Smith, Katherine	282,111		2023-12-31
8	Corporate Secretary	 Gayle Littleton	676,000	2024-02-01	

Name of Respondent:	This report is: (1) An Original	Date of Report:	Year/Period of Report
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**(a) Concept: OfficerName**  
 Effective September 5, 2023, Morion Bell-Izzard resigned from her role as Sr. Vice President, Customer Operations.

**(b) Concept: OfficerName**  
 Effective December 31, 2023, Katherine Smith resigned from her role as Corporate Secretary.

**(c) Concept: OfficerName**  
 Effective February 1, 2024, Gayle Littleton assumed the role of Corporate Secretary.

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**DIRECTORS**

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	J. Tyler Anthony (President & CEO)	701 Ninth Street, N.W., Washington, D.C. 20068	false	false
2	Calvin G. Butler, Jr.	10 S. Dearborn Street, 54th Floor, Chicago, Illinois 60603	false	false

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**INFORMATION ON FORMULA RATES**

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

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	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
7	Attachment H-3D of PJM OATT	ER19-6, FAS 109
8	Attachment H-3D of PJM OATT	ER20-2198, Transmission Formula Rate modification
9	Attachment H-3D of PJM OATT	ER20-1188, Material and Supplies (M&S)
10	Attachment H-3D of PJM OATT	ER21-2965, Transmission Wages and Salary (W&S) Allocator
11	Attachment H-3D of PJM OATT	ER22-2201, Transmission Depreciation Rates

FERC FORM No. 1 (NEW. 12-08)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding**

	Yes
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Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?		No			
If yes, provide a listing of such filings as contained on the Commission's eLibrary website.					
Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20230512-5142	05/12/2023	ER09-1158	Informational Filing of Annual Formula	

FERC FORM NO. 1 (NEW. 12-08)

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Name of Respondent: Delmarva Power & Light Company		This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
<b>INFORMATION ON FORMULA RATES - Formula Rate Variances</b>				
<p>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.</p> <p>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.</p> <p>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.</p> <p>4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.</p>				
Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1		Not Applicable		

FERC FORM No. 1 (NEW. 12-08)

Page 106b

Name of Respondent: Delmarva Power & Light Company		This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
<b>IMPORTANT CHANGES DURING THE QUARTER/YEAR</b>				
<p>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.</p> <ol style="list-style-type: none"> <li>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.</li> <li>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.</li> <li>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.</li> <li>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.</li> <li>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.</li> <li>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.</li> <li>Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.</li> <li>State the estimated annual effect and nature of any important wage scale changes during the year.</li> <li>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.</li> <li>Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.</li> <li>(Reserved.)</li> <li>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.</li> <li>Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.</li> <li>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.</li> </ol>				
1. None				
2. None				
3. None				
4. None				
5. None				
<p>6. Refer to Note 10, "Debt and Credit Agreements" of the accompanying "Notes to the Financial Statements" and back schedule pages 256 - 257 for a discussion of DPL's debt. The authorizations for the issuances of long-term debt are Delaware Public Service Commission (DEPSC) order number 10143 and Maryland Public Service Commission (MDPSC) order number 90447. DPL has authorization from FERC to issue short-term debt securities in an amount not to exceed \$500 million outstanding at any one time in docket ES24-2-000.</p> <p>As of December 31, 2023, DPL had an effective shelf registration statement unlimited in amount, filed with the SEC, that was set to expire on August 3, 2025. As of February 20, 2024, Exelon Corporation filed with the SEC a post-effective amendment to its shelf registration statement to remove and withdraw registration of all DPL's registered securities. DPL is listed as a co-registrant on the post-effective amendment and additionally filed the amendment to deregister all securities that remained unsold. DPL periodically issues securities through the private placement markets. DPL's ability to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, DPL's current financial condition, its securities ratings and market conditions.</p>				
7. None				
8. None				
9. Refer to Note 12, "Commitments and Contingencies" of the accompanying "Notes to Financial Statements" for a discussion of DPL's legal proceedings.				

10. None

13. See Officers page (Page 104) and Directors page (Page 105) for details concerning changes in the respondent's officers during 2023.

14. DPL participates in a cash management program. As of December 31, 2023, DPL's proprietary capital ratio is greater than 30 percent.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)**

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	<b>UTILITY PLANT</b>			
2	Utility Plant (101-106, 114)	200	6,787,512,529	6,370,400,367
3	Construction Work in Progress (107)	200	347,229,662	264,332,443
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,134,742,191	6,634,732,810
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,953,139,902	1,802,012,656
6	Net Utility Plant (Enter Total of line 4 less 5)		5,181,602,289	4,832,720,154
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,181,602,289	4,832,720,154
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	<b>OTHER PROPERTY AND INVESTMENTS</b>			
18	Nonutility Property (121)		16,086,943	14,070,447
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,632,691	4,598,736
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		95,665	198,186
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		11,549,917	9,669,897
33	<b>CURRENT AND ACCRUED ASSETS</b>			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		15,601,254	30,983,618
36	Special Deposits (132-134)		276,547	120,757,660
37	Working Fund (135)			

38	Temporary Cash Investments (136)		459,425	112,661
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		119,408,873	129,643,784
41	Other Accounts Receivable (143)		50,822,325	52,895,932
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		26,163,316	27,834,321
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		644,936	266,917
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	71,822,527	57,821,838
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	8,204,386	8,360,767
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		7,842,295	17,130,555
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,012,622	1,231,075
57	Prepayments (165)		26,543,340	23,697,652
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		3,577	1,742
60	Rents Receivable (172)		1,117,010	984,583
61	Accrued Utility Revenues (173)		63,939,750	74,475,104
62	Miscellaneous Current and Accrued Assets (174)		1,563,816	1,521,538
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		343,099,367	492,051,105
68	<b>DEFERRED DEBITS</b>			
69	Unamortized Debt Expenses (181)		16,360,028	12,380,165
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	161,267,909	180,806,450
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	138,352,496	154,740,210
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		3,173,835	3,791,624
82	Accumulated Deferred Income Taxes (190)	234	131,295,525	139,573,705

83	Unrecovered Purchased Gas Costs (191)		
84	Total Deferred Debits (lines 69 through 83)		450,449,793
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,986,701,366
			491,292,154
			5,825,733,310

FERC FORM No. 1 (REV. 12-03)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	<b>PROPRIETARY CAPITAL</b>			
2	Common Stock Issued (201)	250	2,250	2,250
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		537,612,396	537,612,396
7	Other Paid-In Capital (208-211)	253	926,561,747	828,253,405
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	9,924,450	9,924,450
11	Retained Earnings (215, 215.1, 216)	118	632,552,822	589,200,458
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,177,779)	(2,177,779)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		2,084,626,986	1,942,966,280
17	<b>LONG-TERM DEBT</b>			
18	Bonds (221)	256	2,057,230,000	1,907,230,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	10,000,000	10,000,000
22	Unamortized Premium on Long-Term Debt (225)		658,328	1,126,004
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,176,211	1,230,116
24	Total Long-Term Debt (lines 18 through 23)		2,066,712,117	1,917,125,888
25	<b>OTHER NONCURRENT LIABILITIES</b>			
26	Obligations Under Capital Leases - Noncurrent (227)		23,625,175	26,700,373
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		5,891,459	9,242,849
29	Accumulated Provision for Pensions and Benefits (228.3)		7,804,449	10,457,165
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		12,464,471	12,963,876
35	Total Other Noncurrent Liabilities (lines 26 through 34)		49,785,554	59,364,263
36	<b>CURRENT AND ACCRUED LIABILITIES</b>			

37	Notes Payable (231)			62,968,099	114,909,268
38	Accounts Payable (232)			123,108,151	150,758,341
39	Notes Payable to Associated Companies (233)				
40	Accounts Payable to Associated Companies (234)			25,370,348	22,392,233
41	Customer Deposits (235)			30,640,077	28,903,784
42	Taxes Accrued (236)	262		30,549,303	7,692,042
43	Interest Accrued (237)			13,322,596	9,301,308
44	Dividends Declared (238)				
45	Matured Long-Term Debt (239)				
46	Matured Interest (240)				
47	Tax Collections Payable (241)			554,751	688,137
48	Miscellaneous Current and Accrued Liabilities (242)			69,000,999	171,075,991
49	Obligations Under Capital Leases-Current (243)			5,771,061	5,148,349
50	Derivative Instrument Liabilities (244)				
51	(Less) Long-Term Portion of Derivative Instrument Liabilities				
52	Derivative Instrument Liabilities - Hedges (245)				
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges				
54	Total Current and Accrued Liabilities (lines 37 through 53)			361,285,385	510,869,453
55	<b>DEFERRED CREDITS</b>				
56	Customer Advances for Construction (252)			31,911,415	15,540,959
57	Accumulated Deferred Investment Tax Credits (255)	266		833,420	1,084,374
58	Deferred Gains from Disposition of Utility Plant (256)				
59	Other Deferred Credits (253)	269		28,842,636	26,415,927
60	Other Regulatory Liabilities (254)	278		328,455,425	343,951,133
61	Unamortized Gain on Reacquired Debt (257)				
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272			
63	Accum. Deferred Income Taxes-Other Property (282)			947,474,500	907,921,311
64	Accum. Deferred Income Taxes-Other (283)			86,773,928	100,493,722
65	Total Deferred Credits (lines 56 through 64)			1,424,291,324	1,395,407,426
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)			5,986,701,366	5,825,733,310

FERC FORM No. 1 (REV. 12-03)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**STATEMENT OF INCOME**

Quarterly

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

Annual or Quarterly if applicable

Do not report fourth quarter data in columns (e) and (f)  
Report amounts for accounts 412 and 413. Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.  
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.  
Use page 122 for important notes regarding the statement of income for any account thereof.  
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year 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.  
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.  
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.  
Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of





75	Net Extraordinary Items (Total of line 73 less line 74)												
76	Income Taxes-Federal and Other (409.3)	262											
77	Extraordinary Items After Taxes (line 75 less line 76)												
78	Net Income (Total of line 71 and 77)		176,752,364	168,172,158									

FERC FORM No. 1 (REV. 02-04)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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STATEMENT OF RETAINED EARNINGS

- Do not report Lines 49-53 on the quarterly report.
- Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
- 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).
- State the purpose and amount for each reservation or appropriation of retained earnings.
- 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.
- Show dividends for each class and series of capital stock.
- Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
- 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.
- If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		589,200,458	563,758,300
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		176,752,364	168,172,158
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Common Stock (Dividends paid to Parent)		(133,400,000)	(142,730,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(133,400,000)	(142,730,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		632,552,822	589,200,458
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		632,552,822	589,200,458
	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	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		(2,177,779)	(2,177,779)

FERC FORM No. 1 (REV. 02-04)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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STATEMENT OF CASH FLOWS

- 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.
- 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.
- 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.
- Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	176,752,364	168,172,158
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	191,230,055	171,189,769
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of regulatory debits/credits and limited plant	52,316,289	55,036,370
5.2	Amortized Plant Acquisition Adjustment		926,727
5.3	Unamortized Discount (Premium) on Long-Term Debt	1,205,784	1,498,314
8	Deferred Income Taxes (Net)	2,741,816	16,817,435
9	Investment Tax Credit Adjustment (Net)	(250,954)	(294,568)
10	Net (Increase) Decrease in Receivables	20,660,586	(46,530,824)
11	Net (Increase) Decrease in Inventory	(4,493,976)	(11,187,960)
12	Net (Increase) Decrease in Allowances Inventory	156,381	(554,550)
13	Net Increase (Decrease) in Payables and Accrued Expenses	(5,206,072)	5,204,471
14	Net (Increase) Decrease in Other Regulatory Assets	(8,057,441)	(37,989,080)
15	Net Increase (Decrease) in Other Regulatory Liabilities	14,151,973	17,483,075
16	(Less) Allowance for Other Funds Used During Construction	10,338,511	7,224,373
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Pension	17,359,536	4,894,810
18.2	Other Operating Activities	17,590,980	(299,259)
18.3	Net Increase (Decrease) in Interest and Taxes Accrued	27,588,806	1,191,376
18.4	(Gain) Loss on Sales of Assets	(720,026)	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	492,687,590	338,333,891
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(572,549,219)	(436,892,260)
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	(10,338,511)	(7,224,373)
31	Other (provide details in footnote):		

31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(562,210,708)	(429,667,887)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Proceeds from sale of assets		
53.2	Change in PHI Intercompany Pool		
53.3	Other Investing Activities	(3,498,026)	(474,127)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(565,708,734)	(430,142,014)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	650,000,000	125,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contribution from Parent	98,308,342	147,771,356
70	Cash Provided by Outside Sources (Total 61 thru 69)	748,308,342	272,771,356
72	Payments for Retirement of:		
73	Long-term Debt (b)	(500,000,000)	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Cost of Issuances	(4,981,629)	(1,530,244)
78	Net Decrease in Short-Term Debt (c)	(51,941,169)	(33,647,090)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(133,400,000)	(142,730,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	57,985,544	94,864,022
85	Net Increase (Decrease) in Cash and Cash Equivalents		

86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(15,035,600)	3,055,899
88	Cash and Cash Equivalents at Beginning of Period	31,096,279	28,040,380
90	Cash and Cash Equivalents at End of Period	16,060,679	31,096,279

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

<b>(a) Concept: Other Adjustments To Cash Flows From Operating Activities Description</b>			
Other Operating Activities:			
	<b>2023</b>		<b>2022</b>
Net increases in Prepayments	\$ (2,845,688)	\$	(2,257,374)
Net (increase) decrease in Miscellaneous long term assets and deferred debits	(1,014,181)		449,609
Net increase (decrease) in Other deferred credits	2,426,709		(3,092,209)
Principal Portion of Capital Lease Payments	(6,099,963)		(5,328,834)
Net decrease (increase) in Special Deposits	120,481,113		(77,754,945)
Net increase in Short-term Contract Liabilities	384,243		—
Net (decrease) increase in Collateral received, net	(120,481,239)		77,755,307
Net increases in Customer Advances for Construction	16,370,456		3,400,396
Other	8,369,530		6,528,791
Total Other Operating Activities	\$ 17,590,980	\$	(299,259)
Net decrease in Short-term Contract Liabilities of \$202,669 was disclosed in Line 13 as "Net Increase (Decrease) in Payables and Accrued Expenses" in the 2022 Form 1. The current period Net increase in Short-term Contract Liabilities amount \$384,243 is included within Line 19 as "Other Operating Activities" within the 2023 Form 1.			
<b>(b) Concept: Other Adjustments To Cash Flows From Investment Activities Description</b>			
Other Investing Activities:			
	<b>2023</b>		<b>2022</b>
Re-capitalized Facilities Depreciation	\$ —	\$	1,874,827
Other	(3,498,026)		(2,348,954)
Total Other Investing Activities	\$ (3,498,026)	\$	(474,127)
Re-capitalized facilities depreciation was disclosed in Line 54 as "Other Investing Activities" in the 2022 Form 1. The current period Re-capitalized facilities depreciation amount of \$1,943,456 is included within Line 26 as "Gross Additions to Utility Plant (less nuclear fuel)" within the 2023 Form 1.			

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Page 120-121

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**NOTES TO FINANCIAL STATEMENTS**

- 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.
- 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.
- 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.
- 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.
- Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
- 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.
- 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.
- 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.
- 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.

The notes presented herein were derived from the notes disclosed within the Annual Report of Exelon Corporation (Exelon) Form 10-K for the fiscal year ended December 31, 2023. The notes presented herein were modified to include information relevant to Delmarva Power & Light Company (DPL). All amounts presented within the footnotes are rounded in millions unless otherwise noted.

**1. Significant Accounting Policies**

**Description of Business**

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 portions of New Castle County in Delaware.

**Basis of Presentation**

DPL is an indirect, wholly owned, subsidiary of Exelon.

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the DEPSC, MDPS, and FERC. 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 of America (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 net amount, the exclusion of FIN 48 liabilities related to temporary income tax differences, the derecognition of operating leases from the balance sheet, the classification of cloud computing costs, and the classification of certain other assets and liabilities as current instead of noncurrent.

**COVID-19**

DPL has taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19). DPL provides a critical service to its customers and has taken measures to keep employees who operate the business safe and minimize unnecessary risk of exposure to the virus, including extra precautions for employees who work in the field. DPL has implemented work from home policies where appropriate.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. As of December 31, 2023 and 2022, and through the date of this report, management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, accumulated provision for uncollectible accounts and the carrying value of goodwill and other long-lived assets, in context with the information reasonably available and the unknown

future impacts of COVID-19. DPL's future assessment of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to their consolidated financial statements in future reporting periods.

#### Use of Estimates

The preparation of financial statements in conformity with USOA 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 pension and other postretirement employee benefits (OPEB), unbilled energy revenues, accumulated provision for uncollectible accounts, inventory reserves, asset impairment assessments, derivative instruments, fixed asset depreciation, environmental costs and other loss contingencies, asset retirement obligations (AROs), and taxes. Actual results could differ from those estimates.

#### Regulatory Accounting

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 MDPSC and the DEPSC, 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 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 power and utility revenues from alternative revenue programs (ARP). 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 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. DPL recognizes all ARP revenues that will be collected within 24 months of the end of the annual period in which they are recorded. See Note 2 - Regulatory Matters 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 electricity and gas. 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 14 - Supplemental Financial Information for DPL's taxes that are presented on a gross basis.

#### Income Taxes

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, net or Other, net (interest income) and recognize penalties related to unrecognized tax benefits in Other, net in its Statement of Income.

#### 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. Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2023 and 2022, DPL's restricted cash and cash equivalents primarily represented funds restricted for the collateral held from energy suppliers.

#### Accumulated Provision for Uncollectible Accounts on Accounts Receivables

The accumulated provisions for uncollectible accounts reflects DPL's best estimates of losses on the customers' accounts receivable balances based on historical experience, current information, and reasonable and supportable forecasts.

The accumulated provisions for uncollectible accounts for DPL's customers is developed by applying DPL's loss rates, based on historical loss experience, current conditions, and forward-looking risks factors to the outstanding receivable balance by customer risk segment. DPL's customer accounts are written off consistent with approved regulatory requirements. Adjustments to the accumulated provisions for uncollectible accounts are primarily recorded to Operating and maintenance expense on DPL's Statement of Income or Regulatory assets and liabilities on DPL's Balance Sheet. See Note 2 - Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts on customer accounts receivable at DPL.

DPL has certain non-customer receivables in Other deferred debits and other assets which primarily are with governmental agencies and other high-quality counterparties with no history of default. As such, the allowance for uncollectible accounts related to these receivables is not material. DPL monitors these balances and will record an allowance if there are indicators of a decline in credit quality. See Note 4 - Accounts Receivable for additional information.

#### Inventories

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Fossil fuel and materials and supplies are generally included in inventory when purchased. Fossil fuel is expensed to Purchased power and fuel expense when used or sold. Materials and supplies generally includes transmission and distribution 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 and 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 and minor replacements of property is 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.

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.** 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. Similar costs incurred for cloud-based solutions treated as service arrangements 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.

**Allowance for Funds Used During Construction (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 5 - Property, Plant, and Equipment for additional information.

#### 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 or composite 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 and historical retirements.

See Note 5 - 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. Except for the regulatory assets and liabilities discussed above, amortization is generally recorded to Depreciation and amortization in DPL's Statement of Income when the recovery period is more than one year.

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

#### Asset Retirement Obligations

DPL estimates and recognizes a liability for its legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. DPL updates their AROs either annually or on a rotational basis at least once every three years, based on a risk profile, unless circumstances warrant more frequent updates. The updates factor in new cost estimates, credit-adjusted, risk-free rates (CARFR) and escalation rates and the timing of cash flows. AROs are accrued throughout each year to reflect the time value of money for these present value obligations through an increase to regulatory assets. See Note 6 - Asset Retirement Obligations for additional information.

#### Guarantees

If necessary, DPL recognizes a liability at the time of issuance of a guarantee for the fair value of the obligations they have undertaken by issuing the guarantee. The liability is reduced or eliminated 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 12 - Commitments and Contingencies for additional information.

#### Asset Impairments

**Long-Lived Assets.** DPL evaluates the carrying value of long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include specific regulatory disallowance, abandonment, or plans to dispose of a long-lived asset significantly before the end of its useful life. When the estimated undiscounted future cash flows attributable to the long-lived asset may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its fair value.

#### Derivative Financial Instruments

Derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales (NPNS) exception. For derivatives that qualify and are designated as cash flow hedges, changes in fair value each period are initially recorded in Accumulated other comprehensive income (AOCI) and recognized in earnings when the underlying hedged transaction affects earnings. Amounts recognized in earnings are recorded in Interest expense, net on DPL's Statement of Income based on the activity the transaction is economically hedging. Cash inflows and outflows related to derivative instruments designated as cash flow hedges 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.

For derivatives intended to serve as economic hedges, which are not designated for hedge accounting, changes in fair value each period are recognized in earnings or as a regulatory asset or liability each period. Amounts recognized in earnings are recorded in Electric operating revenues, Purchased power and fuel, or Interest expense in the Statement of Income based on the activity the transaction is economically hedging. Changes in fair value are also recorded as a regulatory asset or liability when there is an ability to recover or return the associated costs or benefits in accordance with regulatory requirements. 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 the hedged item. See Note 2 - Regulatory Matters and Note 9 - Derivative Financial Instruments for additional information.

#### Retirement Benefits

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

The plan obligations and costs of providing benefits under these plans are measured as of December 31. The measurement involves various factors, assumptions, and accounting elections. The impact of assumption changes or experience different from that assumed on pension and OPEB 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 market

related value (MRV) of plan assets are amortized over the expected average remaining service period of plan participants. See Note 8 - Retirement Benefits for additional information.

#### New Accounting Pronouncements

##### New Accounting Standards Issued and Not Yet Adopted as of December 31, 2023

The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by DPL in their financial statements as of December 31, 2023. Unless otherwise indicated, DPL is currently assessing the impacts such guidance may have (which could be material) in their 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.

**Improvement to Income Tax Disclosures (Issued December 2023).** Provides additional disclosure requirements related to the effective tax rate reconciliation and income taxes paid. Under the revised guidance for the effective tax reconciliations, entities would be required to disclose: (1) eight specific categories in the effective tax rate reconciliation in both percentages and reporting currency amount, (2) additional information for reconciling items over a certain threshold, (3) explanation of individual reconciling items disclosed, and (4) provide a qualitative description of the state and local jurisdictions that contribute to the majority of the state income tax expense. For each annual period presented, the new standard requires disclosure of the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign. It also requires additional disaggregated information on income taxes paid (net of refunds received) to an individual jurisdiction equal to or greater than 5% of total income taxes paid (net of refunds received). The standard is effective January 1, 2025, with early adoption permitted.

#### 2. Regulatory Matters

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

**Distribution Base Rate Case Proceedings**

The following tables show the completed and pending distribution base rate case proceedings in 2023.

**Completed Distribution Base Rate Case Proceedings**

Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
Maryland <sup>(a)</sup>	May 19, 2022	Electric	\$ 38	\$ 29	9.60%	December 14, 2022	January 1, 2023

(a) Reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025. The MDPSJC awarded DPL electric incremental revenue requirement increases of \$17 million, \$6 million, and \$6 million for 2023, 2024, and 2025, respectively.

**Pending Distribution Base Rate Case Proceedings**

Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Delaware <sup>(a)</sup>	December 15, 2022 (amended September 29, 2023)	Electric	\$ 39	10.50%	Second quarter of 2024

(a) The rates went into effect on July 15, 2023, subject to refund.

**Transmission Formula Rates**

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 update is based on prior year actual costs and current year projected capital additions, accumulated depreciation, Depreciation and amortization expense, and accumulated deferred income taxes. The update also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2023, the following total increases/(decreases) were included in DPL's electric transmission formula rate update:

Filing Date <sup>(a)</sup>	Initial Revenue Requirement Increase	Annual Reconciliation Decrease	Total Revenue Requirement Increase	Allowed Return on Rate Base <sup>(b)</sup>	Allowed ROE <sup>(c)</sup>
May 12, 2023	\$ 32	\$ (3)	\$ 29	7.08 %	10.50 %

(a) Rate is effective June 1, 2023 - May 31, 2024, subject to review by interested parties pursuant to review protocols of DPL's tariff.

(b) Represents the weighted average debt and equity return on transmission rate bases.

(c) The rate of return on common equity for DPL includes a 50-basis-point incentive adder for being a member of a Regional Transmission Organization (RTO).

**Other State Regulatory Matters**

**Maryland Regulatory Matters**

**Maryland Revenue Decoupling.** In 2007, the MDPSJC approved BSAs for DPL, which are decoupling mechanisms. As a result of the decoupling mechanisms, certain operating revenues from electric distribution are not impacted by abnormal weather or usage per customer. The decoupling mechanism eliminates the impacts of abnormal weather or customer usage by recognizing revenues based on an authorized distribution amount per customer by customer class. Operating revenues from electric distribution are, however, impacted by changes in the number of customers.

**Maryland Order Directing the Distribution of Energy Assistance Funds.** On June 15, 2021, the MDPSJC issued an order authorizing the disbursement of funds to utilities in accordance with Maryland COVID-19 relief legislation. Under this order, DPL received funds of \$8 million in July 2021. The funds have been used to reduce or eliminate certain qualifying past-due residential customer receivables.

**EmpOWER Maryland Cost Recovery.** On December 29, 2023, the MDPSJC issued an order authorizing the next three-year program cycle for EmpOWER Maryland and approved various proposals by the program administrators to implement new energy efficiency programs for the 2024-2026 program cycle, as well as continue operating core programs. Historically, DPL deferred most of its energy efficiency program costs to a regulatory asset or capitalized them. Beginning in 2024, DPL will begin deferring less energy efficiency and demand response program costs to a regulatory asset. Additionally, as part of the order, the MDPSJC directed DPL to extend the amortization of unamortized costs as of December 31, 2023 from 5 to 7 years to mitigate customer bill impacts.

**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 at December 31, 2023 and 2022:

Regulatory Assets (Account 182.3)	December 31, 2023	December 31, 2022
Advanced Metering Infrastructure (AMI) programs - deployment costs	\$ 17	\$ 22
AMI programs - legacy meters	14	17
Asset retirement obligations	3	3
COVID-19	6	6
Deferred storm costs	1	2
Electric energy and natural gas costs	4	27
Energy efficiency and demand response programs	75	77
Transmission formula rate annual reconciliations	22	5
Other	19	22
<b>Total regulatory assets</b>	<b>\$ 161</b>	<b>\$ 181</b>
Regulatory Liabilities (Account 254)	December 31, 2023	December 31, 2022
COVID-19	\$ 3	\$ 3
Deferred income taxes	273	305
Electric energy and natural gas costs	16	8
Multi-year plan reconciliations	7	—
Transmission formula rate annual reconciliations	—	1
Over-recovered revenue decoupling	2	6
Other	27	21
<b>Total regulatory liabilities</b>	<b>\$ 328</b>	<b>\$ 344</b>

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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
AMI programs - deployment costs	Represents installation and ongoing incremental costs of new smart meters, including implementation costs of dynamic pricing for energy usage resulting from smart meters.	2030	Yes
AMI programs - legacy meters	Represents early retirement costs of legacy meters.	2030	Delaware - Yes
Asset retirement obligations	Represents future legally required removal costs associated with existing AROs.	Over the life of the related assets.	Maryland - No Yes, once the removal activities have been performed
COVID-19	Represents incremental credit losses and direct costs related to COVID-19 incurred primarily in 2020, partially offset by a decrease in travel costs. Direct costs consisted primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees.	Maryland - \$1 million - 2027 Delaware - \$2 million to be determined in pending distribution rate case filed with DEPSJC.	Maryland - Yes Delaware - No
Deferred income taxes	Represents 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.	Amounts are recoverable 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
Deferred storm costs	Amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland jurisdiction.	2027	Yes
Electric energy and natural gas costs	Represents under (over)-recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	Delaware - Yes Maryland - No
Energy efficiency and demand response programs	Includes under 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 2030 customers.	Maryland - See above regarding EmpOWER Maryland Cost Recovery for additional information	Delaware - No
Multi-year plan reconciliations	Represents (over)-recoveries related to electric distribution multi-year plans.	Maryland - \$7 million to be determined in next multi-year plan filed with MDPSJC.	Maryland - Yes
Transmission formula rate annual reconciliations	Represents 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.	2025	Yes
Under (over) -recovered revenue decoupling	Represents electric and / or gas distribution costs recoverable from or refundable to customers under decoupling mechanisms.	2024	No

**Capitalized Ratemaking Amounts Not Recognized**

As of December 31, 2023 and 2022, DPL had \$1 million and \$2 million 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 Sheet. The earnings on energy efficiency are on DPL Delaware programs only. These amounts will be recognized as revenues in the Statement of Income in the periods they are billable to customers.

**3. Revenue from Contracts with Customers**

DPL recognizes revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that it expects to be entitled to in exchange for those goods or services. DPL's primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services. The performance obligations, revenue recognition and payment terms associated with these sources of revenue are further discussed in the table below. There are no significant financing components for these sources of revenue and no variable consideration.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, DPL has the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, DPL generally recognizes revenue in the amount for which it has the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Revenue Source	Description	Performance Obligation	Timing of Revenue Recognition	Payment Terms
Regulated Electric and Gas Tariff Sales	Sales of electricity and electricity distribution services and natural gas and gas distribution services to residential, commercial, industrial and governmental customers through regulated tariff rates approved by state regulatory commissions.	Delivery of electricity and/or natural gas.	Over time (each day) as the electricity and/or natural gas is delivered to customers. Tariff sales are generally considered daily contracts as customers can discontinue service at any time. <sup>(a)</sup>	Within the month following delivery of the electricity or natural gas to the customer.
Regulated Transmission Services	DPL provides open access to its transmission facilities to PJM Interconnection, LLC ("PJM"), which directs and controls the operation of these transmission facilities and accordingly compensates DPL pursuant to filed tariffs at cost-based rates approved by FERC.	Various including (i) Network Integration Transmission Services (NITS); (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid.	Over time utilizing output methods to measure progress towards completion. <sup>(b)</sup>	Paid weekly by PJM.

- (a) Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While DPL is required under state legislation to bill its customers for the supply and distribution of electricity and/or natural gas, DPL recognizes revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.
- (b) Passage of time is used for NITS and access to the wholesale grid and MWhs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services.

DPL does not incur any material costs to obtain or fulfill contracts with customers.

#### Contract Liabilities

DPL records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. DPL records contract liabilities within Miscellaneous Current and Accrued Liabilities (Account 242) and Other Deferred Credits (Account 253) within DPL's Balance Sheet.

On July 1, 2020, DPL entered into a collaborative arrangement ("Agreement") with an unrelated owner and manager of communication infrastructure (the "Buyer"). Under this arrangement, DPL sold a 60% undivided interest in its portfolio of transmission tower attachment agreements with telecommunications companies to the Buyer, in addition to transitioning management of the day-to-day operations of the jointly-owned agreements to the Buyer for 35 years, while retaining the safe and reliable operation of its utility assets. In return, DPL will provide the Buyer limited access on the portion of the towers where the equipment resides for the purposes of managing the agreements for the benefit of DPL and the Buyer. Pursuant to the Agreement, DPL has the option ("Payment Option"), but not obligation, to sell two additional 10% undivided interests in the

lower attachment agreements to the Buyer for specified consideration. In addition, for an initial period of three years and two, two-year extensions that are subject to certain conditions, the Buyer has the exclusive right to enter into new agreements with telecommunications companies and to receive a specified undivided percentage interest in those new agreements as set forth in the Agreement. DPL received cash and recorded contract liabilities as of July 1, 2020. The revenue attributable to this arrangement will be recognized as Electric operating revenues over the 35 years under the Agreement.

During the fourth quarter of 2023, DPL entered into an amendment to the Agreement ("Amendment") to modify the terms of the Payment Option and the conditions to exercise the exclusive right extensions. Concurrently DPL exercised both Payment Options which also triggered the extension of the exclusive right period until 2027. The Amendment and executed Payment Options represent a contract modification that is accounted for prospectively in accordance with authoritative guidance. DPL received cash and recorded an increase to the contract liabilities as of December 31, 2023 as shown in the table below. The revenue will be recognized as Electric operating revenues over the remaining term of the Agreement (approximately 31 years).

The following table provides a rollforward of the contract liabilities reflected in DPL's Balance Sheet as of December 31, 2023 and 2022.

Balance at December 31, 2021	\$	11
Revenues recognized <sup>(a)</sup>		(1)
Balance at December 31, 2022		10
Consideration received		4
Revenues recognized <sup>(a)</sup>		(1)
Balance at December 31, 2023	\$	13

- (a) Revenue recognized in the years ended December 31, 2023 and 2022, were included in the contract liabilities at December 31, 2022 and 2021, respectively.

#### Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2023. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

This disclosure excludes the Utility Registrants' gas and electric tariff sales contracts and transmission revenue contracts as they generally have an original expected duration of one year or less and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure.

	2024	2025	2026	2027	2028 and thereafter	Total
\$	1	\$	—	\$	—	\$
					12	13

#### 4. Account Receivable

##### Accumulated Provision for Uncollectible Accounts

The following tables present the rollforward of Accumulated Provision for Uncollectible Accounts on Customer Accounts Receivable (Account 144).

		For the Year Ended December 31, 2023
Balance at December 31, 2022	\$	21
Plus: Current period provision for uncollectible accounts <sup>(a)</sup>		9
Less: Write-offs, net <sup>(b)</sup> of recoveries <sup>(c)</sup>		11
Balance at December 31, 2023	\$	19

		For the Year Ended December 31, 2022
Balance at December 31, 2021	\$	18
Plus: Current period provision for uncollectible accounts		12
Less: Write-offs, net of recoveries		9
Balance at December 31, 2022	\$	21

- (a) The change in current period provision for uncollectible accounts is primarily a result of decreased receivable balances.
- (b) The change in write-offs is primarily a result of unfavorable customer payment behavior.
- (c) Recoveries were not material to DPL.

The following tables present the rollforward of Accumulated Provision for Uncollectible Accounts on Other Accounts Receivable (Account 144).

		For the Year Ended December 31, 2023
Balance at December 31, 2022	\$	7
Plus: Current period provision for uncollectible accounts		1
Less: Write-offs, net of recoveries <sup>(a)</sup>		—
Balance at December 31, 2023	\$	8

		For the Year Ended December 31, 2022
Balance at December 31, 2021	\$	8
Plus: Current period provision for uncollectible accounts		(1)
Less: Write-offs, net of recoveries		—
Balance at December 31, 2022	\$	7

- (a) Recoveries were not material to DPL.

#### Accrued Utility Revenues

DPL accrued \$64 million and \$74 million of unbilled revenues as of December 31, 2023 and December 31, 2022, respectively, in Accrued Utility Revenues (Account 173).

#### Purchase of Customer and Other Accounts Receivable

DPL is required under legislation and regulations in Maryland and Delaware, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in its consolidated billing. The following table presents the total receivables DPL purchased:

	For the Years Ended December 31,	
	2023	2022
Total receivables purchased	\$	205
	228	\$

#### 5. Property, Plant, and Equipment

The following table presents the average service life for each asset category in number of years:

Asset Category	Average Service Life (years)
Electric - transmission and distribution	3-75
Gas - transportation and distribution	3-75
Common - electric and gas	5-75
Other property, plant and equipment	10-43

The following table presents the annual depreciation rates for each asset category:

Annual Depreciation Rates	December 31,	
	2023	2022
Electric - transmission and distribution	3.32 %	3.10 %
Gas - transportation and distribution	1.44 %	1.45 %
Common - electric and gas	8.79 %	10.03 %

The credits to AFUDC debt and equity were \$16 million and \$10 million for the years ended December 31, 2023 and 2022, respectively.

DPL's undivided ownership interests in jointly owned transmission facilities with non-affiliated utilities as of December 31, 2023 and 2022 were as follows:

Operator	PSEG/DPL	
	NJDE <sup>(a)</sup>	
<b>DPL's share at December 31, 2023</b>		
Plant in service	\$	3
Accumulated depreciation		2
<b>DPL's share at December 31, 2022</b>		
Plant in service	\$	3
Accumulated depreciation		2

(a) 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.

Certain facilities are fully owned by Exelon through its 100% ownership in DPL and other wholly owned subsidiaries. These facilities are operated by Exelon wholly owned subsidiaries. DPL's material undivided ownership interests in Exelon owned facilities as of December 31, 2023 and 2022 were as follows:

Ownership interest		27 %
<b>DPL's share at December 31, 2023</b>		
Plant in service	\$	4
Accumulated depreciation		—
Construction work in progress		36
<b>DPL's share at December 31, 2022</b>		
Plant in service	\$	4
Accumulated depreciation		—
Construction work in progress		22

DPL's undivided ownership interests in jointly owned plants presented in the tables above, are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. DPL's share of direct expenses is included in operating and maintenance expenses on DPL's Statements of Income.

Refer to Note 1 - Significant Accounting Policies for additional information regarding property, plant and equipment policies and Note 10 - Debt and Credit Agreements for additional information regarding DPL's property, plant, and equipment subject to mortgage liens.

#### 6. Asset Retirement Obligations

DPL has AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and Polychlorinated Biphenyl. See Note 1 - Significant Accounting Policies for additional information on DPL's accounting policy for AROs.

The following table provides a rollforward of the AROs reflected on DPL's Comparative Balance Sheet from December 31, 2021 to December 31, 2023:

ARO at December 31, 2021 (Account 230)	\$	16
Revisions in estimates of cash flows		(3)
ARO at December 31, 2022 (Account 230)		13
Revisions in estimates of cash flows		(1)
Accretion expense <sup>(a)</sup>		1
ARO at December 31, 2023 (Account 230)	\$	13

(a) The majority of the accretion expense is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

#### 7. Income Taxes

##### Components of Income Tax Expense or Benefit

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

Included in operations:	For the Years Ended December 31,	
	2023	2022
Federal		
Current	\$ 25	\$ (2)
Deferred	(6)	2
State		
Current	6	—
Deferred	10	14
Total (Accounts 409.1, 409.2, 410.1, 411.1, 411.4)	\$ 35	\$ 14

##### Rate Reconciliation

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

U.S. Federal statutory rate	For the Years Ended December 31,	
	2023 <sup>(a)</sup>	2022 <sup>(a)(b)</sup>
Increase (decrease) due to:	21.0 %	21.0 %
State income taxes, net of Federal income tax benefit	6.1	6.5
Plant Basis differences	(0.7)	(0.7)
Excess deferred tax amortization	(9.4)	(18.4)
Amortization of investment tax credit, including deferred taxes on basis differences	(0.1)	(0.2)
Tax credits	(0.4)	(0.6)
Other	—	0.1
Effective income tax rate	16.5 %	7.7 %

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.

(b) The lower effective tax rate is primarily related to the acceleration of certain income tax benefits due to distribution and transmission rate case settlements.

##### 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, 2023 and 2022 are presented below:

	At December 31,	
	2023	2022
Plant basis differences	\$ (947)	\$ (906)
Deferred pension and postretirement obligation	(35)	(39)
Deferred debt refinancing costs	(2)	(2)
Regulatory assets and liabilities	45	43
Tax loss carryforward, net of valuation allowances	18	20
Corporate Alternative Minimum Tax	2	—
Other, net	16	15
Deferred income tax liabilities, net (Accounts 190, 282, 283)	(903)	(869)
Unamortized investment tax credits (Account 255)	(1)	(1)
Total deferred income tax liabilities (net) and unamortized investment tax credits	\$ (904)	\$ (870)

The following table provides DPL's federal and state carryforwards, which are presented on a post-apportioned basis and corresponding valuation allowances as of December 31, 2023.

Corporate Alternative Minimum Tax credit carryforward <sup>(a)</sup>	\$	2
State net operating losses and other carryforwards		743
Deferred taxes on state tax attributes (net of federal taxes)		50
Valuation allowance on state tax attributes (net of federal taxes) <sup>(b)</sup>		32
Year in which net operating loss or credit carryforwards will begin to expire <sup>(c)</sup>		2035

- (a) The Corporate Alternative Minimum Tax credit carryforward has an indefinite carryforward period.  
 (b) A full valuation allowance has been recorded against Delaware net operating losses carryforwards due to a change in Delaware tax law that restricts the ability for corporate taxpayers to monetize net operating losses.  
 (c) A portion of the Maryland state net operating loss carryforward have an indefinite carryforward period.

**Tabular Reconciliation of Unrecognized Tax Benefits**

The following table presents changes in unrecognized tax benefits for DPL:

Balance at January 1, 2021	\$	2
Change to positions that only affect timing		1
Balance at December 31, 2021		3
Change to positions that only affect timing		1
Balance at December 31, 2022		4
Change to positions that only affect timing		(2)
Balance at December 31, 2023		2

**Recognition of unrecognized tax benefits**

The following table represents DPL's unrecognized tax benefits that, if recognized, would decrease the effective tax rate.

December 31, 2023	\$	1
December 31, 2022		—
December 31, 2021		—

**Unrecognized tax benefits for which significant increases or decreases are possible within 12 months after the reporting date.**

At December 31, 2023, DPL has \$0 million of unrecognized tax benefits that could significantly decrease within 12 months after the reporting date based on the outcome of pending court cases involving other taxpayers.

**Total amounts of interest and penalties recognized**

DPL's net interest and penalties receivable (payable) related to tax positions are not material as of December 31, 2023 and 2022.

DPL's interest and penalty expense related to tax positions are not material at both December 31, 2023 and 2022.

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

	Open Years
Federal consolidated income tax returns <sup>(a)</sup>	2010-2022
Delaware separate corporate income tax returns	Same as federal
Maryland separate company corporate net income tax returns	Same as federal

(a) DPL is only open to assessment for tax years since joining the Exelon federal consolidated group, beginning in 2016.

**Other Tax Matters**

**Corporate Alternative Minimum Tax**

On August 16, 2022, the IRA was signed into law and implemented a new corporate alternative minimum tax (CAMT) that imposes a 15% tax on modified GAAP net income. Corporations are entitled to a tax credit (minimum tax credit) to the extent the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT.

Based on the existing statute, DPL will be subject to and will report the CAMT on a separate Registrant basis. The deferred tax asset related to the minimum tax credit carryforward will be realized to the extent DPL's deferred tax liabilities exceed the minimum tax credit carryforward. DPL's deferred tax liabilities are expected to exceed the minimum tax credit carryforward to the foreseeable future and thus no valuation allowance is required. DPL is continuing to assess the financial statement impacts of the IRA and will update estimates based on future guidance issued by the U.S. Treasury.

**Long-Term Marginal State Income Tax Rate**

Quarterly, Exelon reviews and updates its marginal state income tax rates for material changes in state tax laws and state apportionment. DPL remeasures its existing deferred income tax balances to reflect the changes in marginal rates, which results in either an increase or a decrease to their net deferred income tax liability balances. DPL records 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. There were no adjustments to DPL's deferred income tax liability balances for the years ended December 31, 2023 and 2022.

**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 federal and state benefits attributable to Exelon is reallocated to DPL and the other Registrants. During 2023, DPL did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of tax net operating loss. DPL's federal tax benefit allocation from Exelon under the Tax Sharing Agreement was \$3 million as of December 31, 2022.

**8. Retirement Benefits**

**Defined Benefit Pension and Other Postretirement Employee Benefits**

Effective February 1, 2022, in connection with the separation, Exelon restructured certain of its qualified pension plans. However, the qualified pension plans DPL participates in were not affected by the restructuring.

The table below shows the pension and OPEB plans in which Pepco employees participated as of December 31, 2023:

Name of Plan <sup>(a)</sup> :
<b>Qualified Pension Plans:</b>
• Exelon Corporation Retirement Program
• Exelon Pension Plan
• Pepco Holdings LLC Retirement Plan
<b>Non-Qualified Pension Plans:</b>
• Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan
• Connectiv Supplemental Executive Retirement Plan
<b>OPEB Plans:</b>
• PECCO Energy Company Retiree Medical Plan
• Exelon Corporation Health Care Program
• BGE Retiree Medical Plan
• Pepco Holdings LLC Welfare Plan for Retirees

(a) Employees generally remain in their legacy benefit plans when transferring between operating companies.

**Cost Allocation to DPL**

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

The amounts below represent DPL's allocated portion of the pension and OPEB plan costs, which were included in Operating Expenses within DPL's Statements of Income and Plant Utility within DPL's Balance Sheet for the years ended December 31, 2023 and 2022.

	2023		2022
Pension and OPEB	\$	18	\$ 3

**Contributions**

The following table provide DPL's contributions to the pension and OPEB plans for the years ended December 31, 2023 and 2022:

	2023		2022
Pension	\$	2	\$ 1
OPEB		2	—

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under the Employee Retirement Income Security Act (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 projected contributions reflect a funding strategy to make annual contributions with the objective of achieving 100% funded status on an accumulated benefit obligation basis over time. Unlike the qualified pension plans, non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery).

DPL's planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2024 are immaterial.

**Defined Contribution Savings Plan**

DPL participates in a 401(k) defined contribution savings plans that are sponsored by Exelon. The plan is qualified under applicable sections of the Internal Revenue Code and allows employees to contribute a portion of their pre-tax and/or 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 employer contributions and employer matching contributions to the savings plans during the years ended December 31, 2023 and 2022.

	2023		2022
Savings Plan Matching Contributions	\$	3	\$ 3

**9. Derivative Financial Instruments**

DPL uses derivative instruments to manage commodity price risk related to ongoing business operations. DPL does not execute derivatives for speculative or proprietary trading purposes.

Authoritative 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 immediately. 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 scope exception (NPNS), cash flow hedges, and fair value hedges. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold

or consumed.

Cash collateral held by DPL must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

#### 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, which are either determined to be non-derivative or classified as economic hedges. DPL procures electric and natural gas supply through a competitive procurement process approved by MDPS&C and DEPS&C. DPL's hedging programs are intended to reduce exposure to energy and natural gas price volatility and have no direct earnings impact as the costs are fully recovered from customers through regulatory-approved recovery mechanisms. The following table provides a summary of DPL's primary derivative hedging instruments, listed by commodity and accounting treatment.

Commodity	Accounting Treatment	Hedging Instrument
Electricity	NPNS	Fixed price contracts for all Standard Offer Service (SOS) requirements through full requirements contracts.
Gas	NPNS	Fixed and index priced contracts through full requirements contracts.
Gas	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability <sup>(a)</sup>	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.

(a) The fair value of the DPL economic hedge is not material as of December 31, 2023 and 2022.

#### Credit Risk

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 has contracts to procure electric and natural gas supply that provide suppliers with a certain amount of unsecured credit. If the exposure on the supply contract exceeds the amount of unsecured credit, the suppliers may be required to post collateral. The net credit exposure is mitigated primarily by the ability to recover procurement costs through customer rates. As of December 31, 2023 and 2022, the amount of cash collateral held with external counterparties by DPL was less than one million and \$121 million, respectively, which is recorded in Miscellaneous Current and Accrued Liabilities (Account 242) in DPL's Balance Sheet. The amount of cash collateral received from external counterparties decreased as of December 31, 2023 due to decreasing energy prices.

DPL's electric supply procurement contracts do not contain provisions that would require them to post collateral. DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty, with thresholds contingent upon DPL's credit rating. As of December 31, 2023, DPL was not required to post collateral for any of these agreements. If DPL lost its investment grade credit rating as of December 31, 2023, it could have been required to post collateral to its counterparties of \$10 million.

#### 10. Debt and Credit Agreements

##### Short-Term Borrowings

DPL meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from PHI intercompany money pool. 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 as of December 31, 2023 and 2022:

	Credit Facility Size as of December 31,		Outstanding Commercial Paper as of December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2023 <sup>(a)</sup>	2022 <sup>(b)</sup>	2023	2022	2023	2022
\$	300	\$ 300	\$ 63	\$ 115	5.60 %	4.76 %

(a) As of December 31, 2023 and December 31, 2022, excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$15 million, respectively. These facilities were entered into on October 6, 2023 and expire on October 4, 2024. These facilities are solely utilized to issue letters of credit. As of December 31, 2023 and December 31, 2022 there were no outstanding letters of credit.

(b) The standard maximum program size for revolving credit facilities is \$300 million for DPL based on the credit agreements in place. However, the facilities at Potomac Electric Power Company (Peppo), DPL, and Atlantic City Electric Company (ACE) have the ability to flex to \$500 million, \$500 million, and \$350 million, respectively. 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 each of Peppo, DPL, or ACE 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 January 2024, this ability was utilized to increase ACE's program size to \$350 million and decrease DPL's program size to \$250 million, which prevents the aggregate amount of outstanding short-term debt from exceeding the \$900 million limit.

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. DPL does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

At December 31, 2023, DPL had the following aggregate bank commitments, credit facility borrowings and available capacity under its credit facilities:

Facility Type	Aggregate Bank Commitment <sup>(a)</sup>	Facility Draws	Outstanding Letters of Credit	Available Capacity as of December 31, 2023	
				Actual	To Support Additional Commercial Paper
Syndicated Revolver <sup>(a)</sup>	\$ 300	\$ —	\$ —	\$ 300	\$ 237

(a) On February 1, 2022, DPL's syndicated revolving credit facilities were replaced with a new 5-year revolving credit facility with an aggregate bank commitment of \$300 million at a variable interest rate of SOFR plus 1.000%.

(b) Excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$15 million. These facilities expire on October 4, 2024. These facilities are solely utilized to issue letters of credit.

##### Revolving Credit Agreements

Borrowings under DPL's revolving credit agreements bear interest at a rate based upon either the prime rate or a SOFR-based rate, plus an adder based upon its credit rating. The adders for the prime based and SOFR based borrowings are 0 basis points and 100 basis points, respectively. If DPL loses its investment grade rating, the maximum adders for prime rate borrowings and SOFR-based rate borrowings would be 65 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.

##### 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. These 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, 2023 and 2022, \$79 million in VRDBs issued by DPL were outstanding and are included in Long-term debt on its Balance Sheet.

##### Long-Term Debt

The following table presents DPL's outstanding long-term debt as of December 31, 2023 and 2022:

	Rates	Maturity Date	December 31,	
			2023	2022
<b>Long-term debt</b>				
First mortgage bonds (Account 221) <sup>(a)(b)</sup>	1.05% - 5.72%	2028 - 2053	\$ 2,024	\$ 1,874
Unsecured tax-exempt bonds (Account 221)	4.15% - 4.20%	2024	33	33
Medium-terms notes (unsecured) (Account 224)	7.72%	2027	10	10
Finance leases (Accounts 227 and 243)	5.62%	2025-2031	29	32
<b>Total long-term debt</b>			<b>2,096</b>	<b>1,949</b>
Unamortized debt discount and premium, net (Accounts 225 and 226) <sup>(c)</sup>			—	—
<b>Long-term debt</b>			<b>\$ 2,096</b>	<b>\$ 1,949</b>

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

(b) On March 20, 2024, DPL entered into a purchase agreement of First Mortgage Bonds of \$100 million and \$75 million at 5.24% and 5.55% due on March 20, 2034 and March 20, 2054, respectively. The closing date of the issuances occurred on March 20, 2024.

(c) The amount in the Unamortized debt discount and premium, net category was less than \$1 million as of December 31, 2023 and 2022.

Long-term debt maturities at DPL in the periods 2024 through 2028 and thereafter are as follows:

Year	DPL
2024	\$ 84
2025	6
2026	6
2027	15
2028	3
Thereafter	1,982
<b>Total</b>	<b>\$ 2,096</b>

#### Debt Covenants

As of December 31, 2023, DPL is in compliance with debt covenants.

#### 11. Fair Value of Financial Assets and Liabilities

DPL measures and classifies fair value measurements in accordance with the hierarchy as defined by GAAP. 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 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.

##### Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of DPL's short-term liabilities and long-term debt as of December 31, 2023 and 2022. DPL has no financial liabilities measured using the Net Asset Value ("NAV") practical expedient.

	December 31, 2023				December 31, 2022					
	Carrying Amount	Level 1	Level 2	Total	Carrying Amount	Level 1	Level 2	Total		
Long-Term Debt, including amounts due within one year (Accounts 221, 224-227, 243) <sup>(a)</sup>	\$ 2,096	\$ —	\$ 694	\$ 1,134	\$ 1,828	\$ 1,949	\$ —	\$ 1,164	\$ 458	\$ 1,622

(a) The carrying amounts of DPL's short-term liabilities as presented on DPL's Balance Sheet are representative of their fair value (Level 2) because of the short-term nature of these instruments.

DPL uses the following methods and assumptions to estimate fair value of financial liabilities recorded at carrying cost:

Long-term debt, including amounts due within one year

Type	Level	Valuation
Taxable Debt Securities	2	The fair value is determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. DPL obtains credit spreads based on trades of existing DPL debt securities as well as other issuers in the utility sector with similar credit ratings. 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.
Variable Rate Financing Debt	2	Debt rates are reset on a regular basis and the carrying value approximates fair value.
Taxable Private Placement Debt Securities	3	Rates are obtained similar to the process for taxable debt securities. Due to low trading volume and qualitative factors such as market conditions, low volume of investors, and investor demand, these debt securities are Level 3.

**Recurring Fair Value Measurements**

The following table presents 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, 2023 and 2022. DPL has no financial assets or liabilities measured using the NAV practical expedient:

As of December 31, 2023	Level 1	Level 2	Level 3	Total
<b>Assets</b>				
Cash equivalents (Accounts 132-134, 136) <sup>(a)</sup>	\$ 1	\$ —	\$ —	\$ 1
<b>Total assets</b>	\$ 1	\$ —	\$ —	\$ 1
<b>Total net assets</b>	\$ 1	\$ —	\$ —	\$ 1

As of December 31, 2022	Level 1	Level 2	Level 3	Total
<b>Assets</b>				
Cash equivalents (Accounts 132-134, 136) <sup>(a)</sup>	\$ 121	\$ —	\$ —	\$ 121
<b>Total assets</b>	\$ 121	\$ —	\$ —	\$ 121
<b>Total net assets</b>	\$ 121	\$ —	\$ —	\$ 121

(a) DPL excluded cash of \$15 million and \$31 million as of December 31, 2023 and December 31, 2022, respectively.

DPL had no Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2023 and 2022.

**Valuation Techniques Used to Determine Fair Value**

**Cash Equivalents.** Investments with original maturities of three months or less when purchased, including mutual and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

**12. Commitments and Contingencies**

**Commitments**

**PHI Merger Commitments**

Approval of the PHI merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments. The following amounts represent total commitment costs that have been recorded since the acquisition date and the total remaining obligations for DPL at December 31, 2023:

December 31, 2023	
<b>Liabilities</b>	
Total commitments	\$ 89
Remaining commitments <sup>(a)</sup>	\$ 3

(a) Remaining commitments extend through 2026 and include accounts receivable forgiveness programs, charitable contributions and rate credits.

**Commercial Commitments**

DPL's commercial commitments as of December 31, 2023, representing commitments potentially triggered by future events, were as follows:

Total	Expiration within					2029 and beyond
	2024	2025	2026	2027	2028	
Surety bonds <sup>(a)</sup>	\$ 7	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values <sup>(b)</sup>	11	2	3	2	2	2
<b>Total commercial commitments</b>	<b>\$ 18</b>	<b>\$ 7</b>	<b>\$ 2</b>	<b>\$ 3</b>	<b>\$ 2</b>	<b>\$ 2</b>

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds. Historically, payments under the guarantees have not been made and the likelihood of payments being required is remote.

(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 lease term associated with these assets ranges from 1 to 8 years. The maximum potential obligation at the end of the minimum lease term would be \$24 million is guaranteed by DPL. Historically, payments under the guarantees have not been made and DPL believes the likelihood of payments being required under the guarantees is remote.

**Leases**

DPL's future minimum lease payments for operating leases as of December 31, 2023 were as follows:

2024	\$ 9
2025	8
2026	5
2027	6
2028	6
Remaining years	21
<b>Total minimum future lease payments</b>	<b>\$ 55</b>

**Environmental Remediation Matters**

**General**

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 their operations 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.

**MGP Sites**

DPL has identified sites where former manufactured gas plant (MGP) or gas purification activities have or may have resulted in actual site contamination. For some of these sites, there are additional potentially responsible parties that may share responsibility for the ultimate remediation of each location. DPL has identified 1 site that is currently under study and the required cost at the site is not expected to be material.

The historical nature of the MGP and gas purification 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 rates.

As of both December 31, 2023 and 2022, DPL had accrued \$1 million in undiscounted amounts for environmental investigation and remediation liabilities in Miscellaneous Current and Accrued Liabilities (Account 242) on its Balance Sheet. 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 by the DEPSC and MDPSPC that prohibit DPL from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as calculated pursuant to the DEPSC's and MDPSPC's ratemaking precedents, or (b) DPL's corporate issuer or senior unsecured credit rating, or its equivalent, is rated by any of the three major credit rating agencies below the generally accepted definition of 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. DPL is also from time to time subject to audits and investigations by the FERC and other regulators. The assessment of whether a loss is probable or reasonably possible, 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.

**13. Shareholder's Equity**

**Common Stock (Account 201)**

The following table presents common stock authorized and outstanding as of December 31, 2023 and 2022:

	Per Value	Shares Authorized	December 31,	
			2023	2022
			Shares Outstanding	
Common stock	\$ 2.25	1,000	1,000	1,000

**Preferred and Preference Securities (Account 204)**

There were no shares of preferred or preference securities authorized as of December 31, 2023 and 2022.

**14. Supplemental Financial Information**

**Supplemental Statement of Income Information**

The following table provides additional information about material items recorded in DPL's Statement of Income for the years ended December 31, 2023 and 2022:

	For the Years Ended December 31,	
	2023	2022
Taxes other than income taxes (Accounts 408.1 and 408.2)	\$ 26	\$ 25
Utility <sup>(a)</sup>		



7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								176,752,364	176,752,364
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**

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

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	6,304,704,832	5,248,425,156	848,890,105				207,389,571
4	Property Under Capital Leases	46,977,537	46,977,537					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	362,407,375	302,190,866	56,445,421				3,771,088
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	6,714,089,744	5,597,593,559	905,335,526				211,160,659
9	Leased to Others							
10	Held for Future Use	23,376,504	23,376,504					
11	Construction Work in Progress	347,229,662	271,243,814	50,975,663				25,010,185
12	Acquisition Adjustments	50,046,281	50,046,281					
13	Total Utility Plant (8 thru 12)	7,134,742,191	5,942,260,158	956,311,189				236,170,844
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,953,139,902	1,552,858,297	264,313,225				135,968,380
15	Net Utility Plant (13 less 14)	5,181,602,289	4,389,401,861	691,997,964				100,202,464
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,791,591,208	1,444,156,685	262,717,902				84,716,621
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	111,502,413	58,655,331	1,595,323				51,251,759
22	Total in Service (18 thru 21)	1,903,093,621	1,502,812,016	264,313,225				135,968,380
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	Amortization of Plant Acquisition Adjustment	50,046,281	50,046,281				
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,953,139,902	1,552,858,297	264,313,225			135,968,380

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)**

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

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

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)**

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
- Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.



42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - 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)						
47	3. Transmission Plant						
48	(350) Land and Land Rights	54,084,159					54,084,159
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	95,996,847	5,639,955	553,244		(9,496,433)	91,587,125
50	(353) Station Equipment	684,010,541	22,714,438	3,303,435		9,496,433	712,917,977
51	(354) Towers and Fixtures	73,958,461	585				73,959,046
52	(355) Poles and Fixtures	597,440,327	54,936,587	3,131,943			649,244,971
53	(356) Overhead Conductors and Devices	326,083,524	49,916,793	1,495,079			374,505,238
54	(357) Underground Conduit	6,076,346	429,454				6,505,800
55	(358) Underground Conductors and Devices	62,696,725	404,629	24,728			63,076,626
56	(359) Roads and Trails	1,110,956					1,110,956
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,901,457,886	134,042,441	8,508,429			2,026,991,898
59	4. Distribution Plant						
60	(360) Land and Land Rights	15,385,479					15,385,479
61	(361) Structures and Improvements	57,478,971	3,379,054	74,983			60,783,042
62	(362) Station Equipment	493,576,977	25,273,845	1,763,842			517,086,980
63	(363) Energy Storage Equipment - Distribution						
64	(364) Poles, Towers, and Fixtures	262,821,650	26,993,143	460,126			289,354,667
65	(365) Overhead Conductors and Devices	475,056,538	40,247,469	2,763,731		1,077,395	513,617,671
66	(366) Underground Conduit	25,983,694	202,400				26,186,094
67	(367) Underground Conductors and Devices	455,932,528	31,508,295	1,280,442			486,160,381
68	(368) Line Transformers	648,952,128	33,931,203	3,258,191			679,625,140
69	(369) Services	227,635,707	10,975,764	348,193			238,263,278
70	(370) Meters	136,593,502	4,549,002	1,604,516			139,537,988
71	(371) Installations on Customer Premises	43,743,729	555,288				44,299,017
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	83,619,928	8,729,597	929,407			91,420,118
74	(374) Asset Retirement Costs for Distribution Plant	5,593,743	(860,340)	126,088			4,607,315
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,932,374,574	185,484,720	12,609,519		1,077,395	3,106,327,170
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	2,998,246					2,998,246
87	(390) Structures and Improvements	55,199,187	4,040,750	1,036,482			58,203,455
88	(391) Office Furniture and Equipment	14,039,372	5,570,387	1,573,262			18,036,497
89	(392) Transportation Equipment	45,313,854	3,902,396				49,216,250
90	(393) Stores Equipment	313,042		160,451			152,591
91	(394) Tools, Shop and Garage Equipment	22,849,883	2,960,476	489,461			25,320,898
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment						
94	(397) Communication Equipment	212,134,267	17,596,221	2,502,991		(1,077,395)	226,150,102
95	(398) Miscellaneous Equipment	5,025,031	202,100	32,019			5,195,112
96	SUBTOTAL (Enter Total of lines 86 thru 95)	357,872,882	34,272,330	5,794,666		(1,077,395)	385,273,151
97	(399) Other Tangible Property	4,735					4,735
98	(399.1) Asset Retirement Costs for General Plant	623,829	126,109				749,938
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	358,501,446	34,398,439	5,794,666		(1,077,395)	386,027,824
100	TOTAL (Accounts 101 and 106)	5,244,623,834	379,936,112	26,966,387			5,597,593,559
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	5,244,623,834	379,936,112	26,966,387			5,597,593,559

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**ELECTRIC PLANT LEASED TO OTHERS (Account 104)**

Line No.	Name of Lessee (a)	(Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)**

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Grasonville Substation : SS336B	12/01/2019	12/31/2024	3,178,224
3	Queenstown Substation: SSTA979	12/01/2019	12/31/2024	1,592,742
4	Ocean City-West Culver : SS322B	11/01/2019	02/28/2024	1,104,133
5	Lakeside Substation Land; 8 Acres, Talbot County MD	12/01/2010	06/01/2030	406,468
6	Magnolia Substation Land: 11+Acres	08/01/2010	06/01/2030	1,180,361
7	Ocean City-St Louis & 2nd : SSTA749	12/01/2020	12/31/2026	760,286

8	Graceton Jenkins Sub	02/15/2021	12/31/2026	1,372,880
9	Maridel Substation	12/31/2022	12/31/2026	5,435,571
10	Assawoman Substation	12/01/2023	12/31/2024	2,520,000
11	Middletown Substation	03/01/2023	12/31/2027	5,534,790
12	Total of Land under \$250,000	12/01/2019	12/31/2025	291,049
21	Other Property:			
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47	TOTAL			23,376,504

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)**

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	6709 Vienna - West Cambridge	21,536,848
2	64405: DPL: Kennett Square TSO Renovation	20,857,454
3	DPL MD CAP: Narrows Substation	14,450,680
4	DPL MD CAP: Queenstown Substation	12,767,047
5	6709 Vienna - W Cambridge Rebuild	12,109,323
6	DPL MD CAP: Queenstown Substation Transformer	11,820,189

7	DPL MD CAP: Queenstown Substation UTSDRD8QG1	11,598,599
8	EU GIS CORE Software	6,572,445
9	Brandywine Switchgear Replacement	6,072,167
10	Crisfield Kings Creek Construction	5,579,669
11	Tower Replacement DE	5,024,950
12	Router Upgr Cores Edges DE	4,469,780
13	Rebuild OH Rear Lot Dist Sys	4,039,979
14	OCMD BatteryStorage substation	3,796,060
15	Basin Road CH Install	3,595,042
16	Cable DE	3,347,592
17	SCB PHI Case #9461 Software	2,822,181
18	Distribution Automation DE	2,790,730
19	Vienna -W Cambridge Underbuild	2,679,275
20	Crisfield substation New 69KV Term	2,521,164
21	DPL MD Distribution Radial Remediation	2,429,744
22	MD Trans Station Service Replacement	2,352,601
23	IDS Design Build Install DE	2,248,474
24	Router Upgr Cores Edges DPL MD	2,053,778
25	DPL Long Radial - Lancaster Pike	2,024,664
26	Milford new T1 Bus upgrade	2,000,540
27	BRO Main Roof Replacement	1,953,934
28	DPL MD: BRO Security Upgrades	1,944,650
29	DPL MD CAP Narrows substation T Line	1,943,353
30	Substation FO Entrance DE	1,877,745
31	DPL KSQ Security Fence	1,823,788
32	Red Lion T1 for 68457	1,791,612
33	Mechanics T1 Failure	1,725,258
34	North Seaford AT1 Auto-Transformer	1,681,075
35	West T4 Transformer Install	1,655,414
36	IDS Design Build Install DPL MD	1,640,888
37	ADMS - Cap Software #2	1,615,984
38	IR Replacement Deter Distribution substation Struct DE	1,608,176
39	Piney Grove AT20 Replacement	1,595,448
40	Crisfield T1 Replace Transformer ECA	1,540,116
41	DE Tr - Civil Assessment III Foundation Structure	1,416,824
42	ECA Distribution Transformers	1,367,387
43	Basin Rd T1 Transformer & Circuit Breaker	1,334,908
44	New Castle T3 Transformer	1,329,256
45	Maridel T1 Replace Transformer ECA	1,300,565
46	Nelson substation: Service Control System	1,295,757
47	Chesapeake College Communication Lines	1,282,809
48	13707 Vienna-Nelson Rebuild MD	1,217,075
49	Milford substation - FEP	1,169,955
50	Todd substation 25kV Feeder	1,107,991
51	Outage Reporting and Analy -CL	1,080,781
52	DPL Steele - FEP	1,053,615

53	Miscellaneous projects under \$1,000,000	60,328,475
43	Total	271,243,814

Name of Respondent: Deimarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)**

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
<b>Section A. Balances and Changes During Year</b>					
1	Balance Beginning of Year	1,328,136,984	1,328,136,984		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	172,978,894	172,978,894		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,119,466	3,119,466		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	332,286	332,286		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	176,430,646	176,430,646		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(26,912,613)	(26,912,613)		
13	Cost of Removal	(39,930,822)	(39,930,822)		
14	Salvage (Credit)	1,343,342	1,343,342		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(65,500,093)	(65,500,093)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				
17.2	Third Party Reimbursements	5,089,148	5,089,148		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,444,156,685	1,444,156,685		
<b>Section B. Balances at End of Year According to Functional Classification</b>					
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	535,348,684	535,348,684		
26	Distribution	811,529,534	811,529,534		
27	Regional Transmission and Market Operation				
28	General	97,278,467	97,278,467		
29	TOTAL (Enter Total of lines 20 thru 28)	1,444,156,685	1,444,156,685		



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42	Total Cost of Account 123.1 \$		Total						

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**MATERIALS AND SUPPLIES**

- 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.
- 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)	51,747,389	66,078,954	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	888,692	902,315	Electric
9	Distribution Plant (Estimated)	5,185,757	4,841,258	Electric & Gas
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)	57,821,838	71,822,527	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not apply to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	57,821,838	71,822,527	







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																			

FERC FORM No. 1 (ED. 12-95)

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr.)] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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20	TOTAL					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)**

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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49	TOTAL					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**Transmission Service and Generation Interconnection Study Costs**

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

6. In column (d) report the amounts received for reimbursement of the study costs at end of period.  
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	<b>Transmission Studies</b>				
2	N/A				
20	Total				
21	<b>Generation Studies</b>				
22	N/A				
39	Total				
40	Grand Total				

FERC FORM No. 1 (NEW. 03-07)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**OTHER REGULATORY ASSETS (Account 182.3)**

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Other Vacation Accrual	3,299,698	18,231,790	Various	18,041,060	3,490,428
2	Asset Retirement Obligation	2,503,479	761,157	108	233,468	3,031,168
3	Transmission Service Revenue	5,020,605	98,230,562	Various	81,485,745	21,765,422
4	DE Renewable Portfolio Surcharge Deferral		43,664,329	254	42,961,685	702,644
5	DE Electric Costs to Achieve (CTA) Deferral	179,795		407.3	105,569	74,226
6	DE SFAS 133 Gas Derivatives	6,862,288	11,716,731	242	15,213,601	3,365,418
7	DE Third Party Supplier Recovery	2,257,139	2,005,325	Various	2,247,285	2,015,179
8	MD Bill Stabilization Adjustment Deferral		60,223,714	Various	60,223,714	
9	MD Third Party Supplier Recovery	643,018	5,699,603	Various	6,342,621	
10	MD Costs to Achieve (CTA) Deferral	268,591		407.3	113,866	154,725
11	MD Rate Case Costs	704,099		928	262,471	441,628
12	DE DSM - Energy Efficiency	777,581	14,583,290	908	15,360,871	
13	AMI / Smart Grid - DE	21,145,877	103,764	Various	4,010,596	17,239,045
14	Recoverable DE DLC Costs	9,345,640		407.3	2,102,472	7,243,168
15	DE Gas IMU	4,617,975	21,208	Various	706,772	3,932,411
16	DE Gas Costs to Achieve (CTA) Deferral	134,904		407.3	49,556	85,348
17	DSM - Energy Efficiency Products MD	61,346,661	24,696,239	407.3	23,415,998	62,626,902
18	DSM - Direct Load Control Program MD	5,622,794	1,199,634	407.3	1,552,669	5,269,759
19	AMI / Smart Grid - MD	6,942,594	72,792	407.3	1,773,172	5,242,214
20	MD AMI Loss on Retirement of Meters	6,179,520		407.3	1,459,367	4,720,153
21	Delaware SOS: Energy	9,996,943	13,464,760	Various	22,955,758	505,945

22	Delaware SOS: Transmission	10,826,615	1,597,835	Various	12,424,450	
23	Delaware SOS: Administrative Costs	734,400	5,436,966	Various	6,171,366	
24	Delaware SOS: Interest	173,213	408,928	431	114,169	467,972
25	Maryland SOS: Energy	4,460,652	21,778,421	Various	26,239,073	
26	Maryland SOS: Transmission	381,136	4,971,189	Various	3,138,523	2,213,802
27	Maryland SOS: Administrative Costs	214,453	2,714,878	407.3	2,154,143	775,188
28	MD Incremental Storm Costs	2,095,026		Various	631,943	1,463,083
29	Tax Cuts and Jobs Act	4,374,232	4,514,428	Various	4,486,054	4,402,606
30	MD RM54 Recovery	47,861		903	47,861	
31	MD Electric Vehicle	906,408	592,071	Various	296,211	1,202,268
32	DE Incremental COVID-19 Cost	5,441,568		N/A		5,441,568
33	MD Incremental COVID-19 Cost	854,200	175,540	407.3	532,748	496,992
34	MD Battery Storage	2,425,963	115,381	Various	357,977	2,183,367
35	MD Incremental IJIA Costs	21,522	67,858	N/A		89,380
36	Accrued Anniversary Credits		2,265,600	407.3	1,639,700	625,900
44	TOTAL	180,806,450	339,313,993		358,852,534	161,267,909

FERC FORM No. 1 (REV. 02-04)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

**(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets**

DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:

Line No.	Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
3	Transmission Service Revenue	FERC Docket No. ER05-515
4	DE Renewable Portfolio Surcharge Deferral	DEPSC Regulation Docket No. 56
5	DE Electric Costs to Achieve (CTA) Deferral	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977, DEPSC Docket No. 20-0149
6	DE SFAS 133 Gas Derivatives	DEPSC Docket No. 97-293F
7	DE Third Party Supplier Recovery	DEPSC Docket No. 15-1693
8	MD Bill Stabilization Adjustment Deferral	MDPSC Case No. 9092, MDPSC Case No. 9093
9	MD Third Party Supplier Recovery	MDPSC Maillog 116829
10	MD Costs to Achieve (CTA) Deferral	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630
11	MD Rate Case Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630, MDPSC Case No. 9670, MDPSC Case No. 9681
12	DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985
13	AMI / Smart Grid - DE	DEPSC Docket No. 11-528, DEPSC Docket No. 13-115, DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977
14	Recoverable DE DLC Costs	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977
15	DE Gas IMU	DEPSC Docket No. 09-277T, DEPSC Docket No. 10-237, DEPSC Docket No. 11-528, DEPSC Docket No. 12-546, DEPSC Docket No. 17-0978
16	DE Gas Costs to Achieve (CTA) Deferral	DEPSC Docket No. 17-0978, DEPSC Docket No. 20-0150
17	DSM - Energy Efficiency Products MD	MDPSC Case No. 9156
18	DSM - Direct Load Control Program MD	MDPSC Case No. 9156
19	AMI / Smart Grid - MD	MDPSC Case No. 9424, MDPSC Case No. 9455
20	MD AMI Loss on Retirement of Meters	MDPSC Case No. 9424
21	Delaware SOS: Energy	DEPSC Docket No. 04-391
22	Delaware SOS: Transmission	DEPSC Docket No. 04-391
23	Delaware SOS: Administrative Costs	DEPSC Docket No. 04-391
24	Delaware SOS: Interest	DEPSC Docket No. 04-391
25	Maryland SOS: Energy	MDPSC Case No. 8908
26	Maryland SOS: Transmission	MDPSC Case No. 8908
27	Maryland SOS: Administrative Costs	MDPSC Case No. 8908
28	MD Incremental Storm Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630, MDPSC Case No. 9670
29	Tax Cuts and Jobs Act	MDPSC Case No. 9630, DEPSC Docket No. 20-0149
30	MD RM54 Recovery	MDPSC Case No. 9630
31	MD Electric Vehicle	MDPSC Case No. 9478, MDPSC Case No. 9681
32	DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286
33	MD Incremental COVID-19 Cost	MDPSC Case No. 9670, MDPSC Case No. 9681
34	MD Battery Storage	MDPSC Case No. 9619, MDPSC Case No. 9681
35	MD Incremental IJIA Costs	MDPSC Final Order No. 90272

**(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets**

DPL amortizes the regulatory assets in account 182.3 based on the following amortization periods:

Line No.	Description of Other Regulatory Assets	Amortization Lives
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5	DE Electric Costs to Achieve (CTA) Deferral	5 years
10	MD Costs to Achieve (CTA) Deferral	5 years
11	MD Rate Case Costs	3 years
13	AMI / Smart Grid - DE	15 years
14	Recoverable DE DLC Costs	10 years
15	DE Gas IMU	15 years
16	DE Gas Costs to Achieve (CTA) Deferral	5 years
17	DSM - Energy Efficiency Products MD	5 years
18	DSM - Direct Load Control Program MD	15 years
19	AMI / Smart Grid - MD	10 years
20	MD AMI Loss on Retirement of Meters	10 years
28	MD Incremental Storm Costs	5 years
29	Tax Cuts and Jobs Act	32 years
30	MD RM54 Recovery	3 years
31	MD Electric Vehicle	5 years
33	MD Incremental COVID-19 Cost	5 years
34	MD Battery Storage	10 years

**(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	10,720,741	recorded to account 242 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability
	720,172	recorded to account 236 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	6,600,147	recorded to account 923
\$	18,041,060	Total

**(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	28,170,483	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue line 20, pg. 278
	53,315,262	recorded to account 456.1
\$	81,485,745	Total

**(e) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "254":

\$	42,961,685	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE Renewable Portfolio Surcharge Deferral line 9, pg. 278
----	------------	---

**(f) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	838,639	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	1,403,732	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
	4,914	recorded to account 557 - Other Expenses
\$	2,247,285	Total

**(g) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	6,360,570	recorded to account 456
	53,862,935	recorded to account 254 - Reclass consistent with regulatory recovery position, included in MD Bill Stabilization Adjustment Deferral line 17, pg. 278
	209	recorded to account 131 - Cash receipt for manually recorded customer bills in line with previous under-recovery
\$	60,223,714	Total

**(h) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	839,867	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	850,166	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
	4,652,588	recorded to account 254 - Reclass consistent with regulatory recovery position included in MD Third Party Supplier Recovery line 26, pg. 278
\$	6,342,621	Total

**(i) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	3,940,784	recorded to account 407.3
	69,812	recorded to account 923
\$	4,010,596	Total

**(j) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	636,271	recorded to account 407.3
	70,501	recorded to account 923
\$	706,772	Total

**(k) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	12,462,379	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Energy line 5, pg. 278
	10,493,379	recorded to account 407.3
\$	22,955,758	Total

**(l) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	1,543,806	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Transmission line 6, pg. 278
	10,880,644	recorded to account 407.3
\$	12,424,450	Total

**(m) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	5,316,871	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Administrative Costs line 7, pg. 278
	854,495	recorded to account 407.3
\$	6,171,366	Total

**(n) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged**

The following are the individual components of "Various":

\$	10,271,017	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Energy line 3, pg. 278
\$	15,968,056	recorded to account 407.3
\$	26,239,073	Total
<b>(q)</b> Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	1,309,376	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Transmission line 4, pg. 278
\$	1,829,147	recorded to account 407.3
\$	3,138,523	Total
<b>(p)</b> Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	460	recorded to account 408.1
\$	625,643	recorded to account 593
\$	5,840	recorded to account 903
\$	631,943	Total
<b>(q)</b> Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	4,374,925	recorded to account 407.3
\$	99,502	recorded to account 923
\$	11,627	recorded to account 254 - Reclass consistent with regulatory position, included in Tax Cuts and Jobs Act line 14, pg. 278
\$	4,486,054	Total
<b>(r)</b> Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	74,225	recorded to account 232 - Payable electric vehicle rebates and admin costs
\$	221,986	recorded to account 407.3
\$	296,211	Total
<b>(s)</b> Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	243,550	recorded to account 407.3
\$	114,427	recorded to account 588
\$	357,977	Total

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**MISCELLANEOUS DEFFERED DEBITS (Account 186)**

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Prepaid Pension Costs	152,569,981	501,605	various	17,861,141	135,210,445
2	LT Customer Payment Receivables	57,247	15,914	143	19,605	53,556
3	LT Receivable from PJM	925,158		143	491,182	433,976
4	Other A/R Worker Compensation	1,181,456	135,284	various	167,712	1,149,028
5	Maintenance and Inspection plan contract		428,633			428,633
6	Deposits for Equipment		1,066,933			1,066,933
7	Concur Expense Management System	6,094	10,458,120	various	10,464,214	
8	Other	274	406,669	242	397,018	9,925
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	154,740,210				138,352,496

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FOOTNOTE DATA

(a) Concept: DescriptionOfMiscellaneousDeferredDebits

Maintenance and Inspection plan contract will be amortized over 10 years.

(b) Concept: DescriptionOfMiscellaneousDeferredDebits

In 2022, \$6,094 of Concur Expense Management System was reported within the "Other" category. In 2023, Concur Expense Management System is broken out in a separate Line Number and is no longer included within the "Other" balance.

(c) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Prepaid Pension Cost is offset in Accounts 228.3, 926, 107, and 108.

(d) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Other A/R Worker Compensation is offset in Accounts 228.2, 925, 107, 108, 143, and 174.

(e) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Concur Expense Management System represents activity for the corporate credit program to be settled/invoiced with the credit card issuing bank. The activity for the corporate credit card program is offset to the following FERC Accounts: 107, 108, 146, 163, 182.3, 184, 232, 417.1, 426.1, 426.4, 426.5, 557, 560, 566, 569, 570, 571, 573, 580, 581, 582, 583, 586, 588, 589, 591, 592, 593, 594, 596, 598, 807, 841, 843.4, 843.5, 843.6, 843.7, 843.9, 859, 863, 870, 874, 875, 878, 879, 880, 885, 887, 889, 892, 893, 894, 902, 903, 908, 920, 923, 928, 930.1, 930.2, and 935.

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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	124,229,077	116,753,668
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	124,229,077	116,753,668
9	Gas		
10	Gas	15,344,628	14,541,857
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	15,344,628	14,541,857
17.1	AMT Credit / Other		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	139,573,705	131,295,525

Notes

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Account 190 Activity		
410.1 Debits	\$	8,937,676
411.1 Credits		(7,594,867)
Net Debits/(Credits)	\$	1,342,809
Account 190 Activity		
410.2 Debits	\$	3,291
411.2 Credits		(1,770,317)
Net Debits/(Credits)	\$	(1,767,026)
Account 190 Activity B/S Only		
410 Debits	\$	—
411 Credits		(8,702,397)
Net Debits/(Credits)	\$	(8,702,397)
<b>Net Change</b>	<b>\$</b>	<b>(8,276,180)</b>



2		1,000	2.25		1,000	2,250			
6	Total	1,000			1,000	2,250			
7	Preferred Stock (Account 204)								
8									
9									
10									
11	Total								
1	Capital Stock (Accounts 201 and 204) - Data Conversion								
2									
3									
4									
5	Total								

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FOOTNOTE DATA			

(a) Concept: CommonStockSharesAuthorized

Reference is made to the Delmarva Power & Light Company's Balance Sheet in the Exelon Corporation Form 10-K page 150, filed with the Securities and Exchange Commission for the year ended December 31, 2023.

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**Other Paid-in Capital**

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

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

Line No.	Item (a)	Amount (b)
1	<b>Donations Received from Stockholders (Account 208)</b>	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	<b>Reduction in Par or Stated Value of Capital Stock (Account 209)</b>	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	<b>Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)</b>	
10	Beginning Balance Amount	1,338,396
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	0
12	Ending Balance Amount	1,338,396
13	<b>Miscellaneous Paid-In Capital (Account 211)</b>	
14	Beginning Balance Amount	826,915,009
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	98,308,342
16	Ending Balance Amount	925,223,351



9	11/15/2023		200,000,000		1,861,600	(4,264,000)		06/09/2014	11/15/2023	06/09/2014	11/15/2023		6,105,556
10	4.15% First Mortgage Bonds due 5/15/2045		175,000,000		1,531,250	(775,250)		12/12/2016	05/15/2045	12/12/2016	05/15/2045	175,000,000	7,262,500
11	4.27% First Mortgage Bonds due 6/15/2048		200,000,000		1,763,969			06/21/2018	06/15/2048	06/21/2018	06/15/2048	200,000,000	8,540,000
12	4.14% First Mortgage Bonds due 12/12/2049		75,000,000		763,717			12/12/2019	12/12/2049	12/12/2019	12/12/2049	75,000,000	3,105,000
13	2.53% First Mortgage Bonds due 6/9/2030		100,000,000		793,037			06/09/2020	06/09/2030	06/09/2020	06/09/2030	100,000,000	2,530,000
14	3.24% First Mortgage Bonds due 3/30/2051		125,000,000		1,010,021			03/30/2021	03/30/2051	03/30/2021	03/30/2051	125,000,000	4,050,000
15	3.06% First Mortgage Bonds due 2/15/2052		125,000,000		1,025,116			02/15/2022	02/15/2052	02/15/2022	02/15/2052	125,000,000	3,825,000
16	5.30% First Mortgage Bond due 3/15/2033		60,000,000		619,307			<sup>(a)</sup> 03/15/2023	03/15/2033	03/15/2023	03/15/2033	60,000,000	2,526,333
17	5.57% First Mortgage Bond due 3/15/2053		65,000,000		666,068			<sup>(b)</sup> 03/15/2023	03/15/2053	03/15/2023	03/15/2053	65,000,000	2,876,286
18	5.45% First Mortgage Bond due 11/8/2033		340,000,000		2,227,664			<sup>(c)</sup> 11/08/2023	11/08/2033	11/08/2023	11/08/2033	340,000,000	2,728,028
19	5.55% First Mortgage Bond due 11/8/2038		75,000,000		491,305			<sup>(d)</sup> 11/08/2023	11/08/2038	11/08/2023	11/08/2038	75,000,000	612,813
20	5.72% First Mortgage Bond due 11/8/2058		110,000,000		720,707			<sup>(d)</sup> 11/08/2023	11/08/2053	11/08/2023	11/08/2053	110,000,000	926,322
21	Tax Exempt Bonds		78,400,000		851,895			07/01/2020	07/01/2025	07/01/2020	07/01/2025	78,400,000	823,200
22	Subtotal		2,557,230,000		22,450,127	(5,039,250)	810,500					2,057,230,000	76,129,060
23	Reacquired Bonds (Account 222)												
24													
25													
26													
27	Subtotal												
28	Advances from Associated Companies (Account 223)												
29													
30													
31													
32	Subtotal												
33	Other Long Term Debt (Account 224)												
34	Medium Term Notes 7.72% Series C		10,000,000					02/07/1997	02/01/2027	02/07/1997	02/01/2027	10,000,000	772,000
35	Subtotal		10,000,000									10,000,000	772,000
33	TOTAL		2,567,230,000									2,067,230,000	76,901,060

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FOOTNOTE DATA			

<sup>(a)</sup> Concept: NominalDateOfIssue  
\$80 million of First Mortgage Bonds were issued on March 15, 2023.

<sup>(b)</sup> Concept: NominalDateOfIssue  
\$65 million of First Mortgage Bonds were issued on March 15, 2023.

<sup>(c)</sup> Concept: NominalDateOfIssue  
\$340 million of First Mortgage Bonds were issued on November 8, 2023.

<sup>(d)</sup> Concept: NominalDateOfIssue  
\$75 million of First Mortgage Bonds were issued on November 8, 2023.

(e) Concept: NominalDateOfIssue

\$110 million of First Mortgage Bonds were issued on November 8, 2023.

(f) Concept: InterestExpenseOnLongTermDebtIssued

The difference between the total interest reported in column (m) and the balance in account 427 is \$11,433, which represents Service Company related interest from money pool transactions and credit facility commitment fees each of which are reported in account 430.

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	176,752,364
2	Reconciling Items for the Year	
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	35,155,471
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	SEE FOOTNOTE	(104,454,846)
27	Federal Tax Net Income	107,452,989
28	Show Computation of Tax:	
29	Federal Income Tax at 21%	22,565,127
30	SEE FOOTNOTE	3,700,039
31	TOTAL	26,265,166
32	Federal Income Tax Acct 409.10	25,511,096
33	Federal Income Tax Acct 409.20	754,071
34	Total	26,265,167

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FOOTNOTE DATA

(a) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Net Income for the Year (Page 117)	\$	176,752,364
Federal Income Taxes		18,770,447
State Income Taxes		16,385,024

Pre-tax Book Income	\$	211,907,835
Increase (Decrease) in Taxable Income Resulting From:		
Removal Costs	\$	(42,998,738)
Mixed Service Costs		(78,582,002)
Repair Allowance - Unit of Property		(91,671,052)
Bonus Depreciation		—
Depreciation		62,960,659
CIAC		12,180,079
AFUDC Equity		(10,338,511)
AFUDC Debt		(5,875,009)
Capitalized Interest		8,216,878
Gain/Loss on Disposition of Property		(3,211,728)
Other (Property)		3,909,648
Regulatory Assets & Liabilities		40,062,735
Pension/OPEB/SERP		7,489,695
Accrued Liabilities		(784,461)
Merger Commitment Deferrals		—
State Income Taxes Deductible		(6,005,182)
Deferred Revenue		3,187,831
Other (Net)		(2,995,694)
Total Schedule M's	\$	(104,454,846)
Federal Taxable Income		107,452,989
Computation of Federal Income Tax:		
Federal Income Tax on Current Year Income (21%)	\$	22,565,127
Corporate Alternative Minimum Tax Adjustment		1,595,411
Net Operating Loss Utilized		—
Return to Accrual True Up		3,184,357
Amended Return Adjustments		(400,877)
State Notice Payment or Refund		8,923
Income Tax Credits		(687,775)
Federal Income Tax	\$	26,265,166
Federal Income Tax Account 409.10	\$	25,511,096
Federal Income Tax Account 409.20		754,071
Total	\$	26,265,167
<b>Additional information in response to Instruction 2, Page 261:</b>		
The Respondent is a wholly owned subsidiary of Exelon Corporation. The Respondent files a consolidated tax return with Exelon Corporation and Exelon Corporation's other subsidiaries. The consolidated federal income tax liability was allocated to the Respondent on a separate-return basis.		
Corporate Alternative Minimum Tax Adjustment: This adjustment represents the difference between regular tax calculated at 21% of taxable income to the Corporate Alternative Minimum Tax calculated at 15% of Adjusted Financial Statement Income.		

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**TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR**

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

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1					0	0				0					
2	<b>Subtotal Federal Tax</b>				0	0				0	0				
3	<b>Subtotal State Tax</b>				0	0				0	0				
4	<b>Subtotal Local Tax</b>				0	0				0	0				
5	Public Service Commission (PSC)	Other Taxes	MD	2023	0	0	1,209,072	1,209,072		0		1,209,072			
6	Reg Asset Assessment - Electric	Other Taxes	DE	2023	1,764,163	0	2,011,608	1,975,266		1,800,505		2,011,608			
7	Reg Asset Assessment - Gas	Other Taxes	DE	2023	158,849	0	576,133	643,050		91,932					576,133

8	Environmental Surcharge	Other Taxes	MD	2023	55,078	0	582,970	582,737		55,311		582,970		
9	Other Taxes	Other Taxes	MD	2023						0				
10	GRT/Professional Services - Electric	Other Taxes	DE	2023	55,209	0	614,703	621,641		48,271		614,703		
11	GRT/Professional Services - Electric Reserve	Other Taxes	DE	2023	16,665	0	(12,284)	4,381				(12,284)		
12	GRT/Professional Services - Gas	Other Taxes	DE	2023	2,017	0	42,455	42,104		2,368				42,455
13	Public Utility Tax - Electric	Other Taxes	DE	2023	706,195	0	8,643,772	8,664,594		685,373		8,643,772		
14	Public Utility Tax - Gas	Other Taxes	DE	2023	372,382	0	2,786,725	2,909,731		249,376				2,786,725
15	<b>Subtotal Other Tax</b>				3,130,558		16,455,154	16,652,576		2,933,136		13,049,841		3,405,313
16	Property Taxes	Property Tax	MD	2023		11,709,629	21,625,811	25,778,706	3,115,793	0	12,746,731	21,625,811		
17	Property Taxes - Other	Property Tax	MD	2023	31,011	0		(33,457)	(32,234)	32,234				
18	Property Taxes	Property Tax	DE	2023	0	10,984,552	21,654,081	23,173,734	976,389	0	11,527,816	12,989,982		8,664,099
19	Property Taxes	Property Tax	VA	2023	0	0	146,430	145,935	(495)	0		146,430		
20	Property Taxes	Property Tax	WV	2023	0	0	12,251	12,251		0				12,251
21	Property Taxes	Property Tax	MS	2023	0	0	8,351	8,351		0				8,351
22	Property Taxes	Property Tax	NJ	2023	0	0	650,886	650,886		0				650,886
23	Property Taxes	Property Tax	PA	2023	0	42,715		106,086	105,702	0	43,099			
24	<b>Subtotal Property Tax</b>				31,011	22,736,896	44,097,810	49,842,492	4,165,155	32,234	24,317,646	34,762,223		9,335,587
25	<b>Subtotal Real Estate Tax</b>				0	0				0	0			
26	<b>Subtotal Unemployment Tax</b>				0	0				0	0			
27	Sales Tax	Sales And Use Tax	MD	2023	0	0	17,311	17,311		0		17,311		
28	Use Tax	Sales And Use Tax	MD	2023	847,162	0		(219,575)		1,066,737				
29	Use Tax Reserve	Sales And Use Tax	MD	2023	667,276	0	52,170	(141)		719,587		52,170		
30	Use Tax	Sales And Use Tax	VA	2023	157,516	0		45,330		112,186				
31	<b>Subtotal Sales And Use Tax</b>				1,671,954	0	69,481	(157,075)		1,898,510	0	69,481		
32	Federal Income Tax	Income Tax	Fed	2023	676,201	0	26,265,167	5,523,333	(3,910,103)	17,507,932		20,870,661		5,394,506
33	State Income Tax - Delaware	Income Tax	DE	2023	0	0	6,399,441	378,788	(8,515)	6,012,138		5,414,909		984,532
34	State Income Tax - Maryland	Income Tax	MD	2023	0	0				0				
35	<b>Subtotal Income Tax</b>				676,201	0	32,664,608	5,902,121	(3,918,618)	23,520,070	0	26,285,570		6,379,038
36	Heavy Highway Excise Tax	Excise Tax	Fed	2023	0	0	29,728	29,728		0		25,567		4,161
37	<b>Subtotal Excise Tax</b>				0	0	29,728	29,728		0	0	25,567		4,161
38	<b>Subtotal Fuel Tax</b>				0	0				0	0			
39	<b>Subtotal Federal Insurance Tax</b>				0	0				0	0			
40	Franchise Tax	Franchise Tax	MD	2023	82,160	0	9,086,663	9,048,316		120,507		9,086,663		
41	Wilmington Franchise Tax	Franchise Tax	DE	2023	860,943	0	900,900	872,316		889,527		900,900		
42	Wilmington Franchise Tax Reserve	Franchise Tax	DE	2023		0	(1)	(1)				(1)		
43	<b>Subtotal Franchise Tax</b>				943,103		9,987,562	9,920,631		1,010,034	0	9,987,562		
44	<b>Subtotal Miscellaneous Other Tax</b>				0	0				0	0			
45	<b>Subtotal Other Federal Tax</b>				0	0				0	0			
46	<b>Subtotal Other State Tax</b>				0	0				0	0			
47	<b>Subtotal Other Property Tax</b>				0	0				0	0			
48	<b>Subtotal Other Use Tax</b>				0	0				0	0			
49	<b>Subtotal Other Advalorem Tax</b>				0	0				0	0			
50	<b>Subtotal Other License And</b>				0	0				0	0			



No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	of Year (h)	Allocation to Income (i)	EXPLANATION (j)
1	Electric Utility									
2	3%									
3	4%	5,670			411.4	1,278		4,392		
4	7%	278,157			411.4	62,687		215,470		
5	10%	729,038			411.4	164,299		564,739		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,012,865				228,264		784,601		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	10% Gas Utility	71,509				22,690		48,819		
12	Total Other	71,509				22,690		48,819		
13	Account 255	1,084,374				250,954		833,420		
47	OTHER TOTAL									
48	GRAND TOTAL	1,084,374						833,420		

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OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Special Billing	2,227,391	various	1,849,244	2,197,427	2,575,574
2	DE Charitable Contributions	1,665,334	426.1	771,186		894,148
3	MD Charitable Contributions	440,065	426.1	203,548		236,517
4	MFN Credits	149,277			64,505	213,782
5	Supplier Deposits	558,842	232	53,051	25,670	531,461
6	Merrill Creek Lease	10,093,485	418	4,294,512	4,027,569	9,826,542
7	Tower Attachment Agreements	9,492,401	various	775,525	3,579,113	12,295,989
8	Maryland Interconnectivity Fee				394,181	394,181
9	Deferred Rent	1,778,446	various	72,751		1,705,695
10	Other	10,686			158,061	168,747
47	TOTAL	26,415,927		8,019,817	10,446,526	28,842,636

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FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits

Merrill Creek Lease credit will be amortized through 2038.

(b) Concept: DescriptionOfOtherDeferredCredits

The Tower Attachment Agreements balance will be amortized and recognized as operating revenue over the 35 years under the collaborative arrangement. Refer to Note 3 "Revenue from Contracts with Customers" of accompanying "Notes to Financial Statements" for a discussion on the Contract Liabilities for the Tower Attachment Agreements.

(c) Concept: DescriptionOfOtherDeferredCredits

In 2022, \$1,778,446 of Deferred Rent was reported within the "Other" category. In 2023, Deferred Rent is broken out in a separate Line Number and is no longer included within the "Other" balance.

(d) Concept: DecreaseInOtherDeferredCreditsContraAccount

Special billing is offset in Accounts 454 and 143.

(e) Concept: DecreaseInOtherDeferredCreditsContraAccount

The Tower Attachment Agreements is offset in Accounts 454 and 242.

(f) Concept: DecreaseInOtherDeferredCreditsContraAccount

Deferred Rent is offset in Accounts 186 and 418.

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

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



Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Electric	89,691,297	1,941,162	13,811,825			254,410,411		254,410,411		77,820,634
4							254,410,411		254,410,411		
9	TOTAL Electric (Total of lines 3 thru 8)	89,691,297	1,941,162	13,811,825							77,820,634
10	Gas										
11	Gas	10,802,425	258,242	2,107,373			254,410,411		254,410,411		8,953,294
12							254,410,411		254,410,411		
17	TOTAL Gas (Total of lines 11 thru 16)	10,802,425	258,242	2,107,373							8,953,294
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	100,493,722	2,199,404	15,919,198							86,773,928
20	Classification of TOTAL										
21	Federal Income Tax	69,672,988	1,524,862	11,036,889			254,410,411		254,410,411		60,160,961
22	State Income Tax	30,820,734	674,542	4,882,309			254,410,411		254,410,411		26,612,967
23	Local Income Tax										
NOTES											

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther					
283	Electric	Gas	Total		
Accrued Property Taxes	\$ 5,519,353	\$ 898,499	\$ 6,417,852		
Asset Retirement Obligation	522,659	85,084	607,743		
Materials Reserve	(108,286)	(17,628)	(125,914)		
Other Deferred Debits	1,554,537	253,064	1,807,601		
Pension Asset	36,364,902	5,919,868	42,284,770		
Regulatory Asset	41,830,735	3,388,387	45,219,122		
Regulatory Asset - Accrued Vacation	786,480	128,032	914,512		
Renewable Energy Credits	2,317,186	—	2,317,186		
Unamortized Loss on Reacquired Debt	903,731	147,119	1,050,850		
<b>Total</b>	<b>\$ 89,691,297</b>	<b>\$ 10,802,425</b>	<b>\$ 100,493,722</b>		
(b) Concept: AccumulatedDeferredIncomeTaxesOther					
283	Electric	Gas	Total		
Accrued Property Taxes	\$ 5,780,866	\$ 941,071	\$ 6,721,937		
Asset Retirement Obligation	523,368	85,199	608,567		
Materials Reserve	(209,265)	(34,066)	(243,331)		
Other Deferred Debits	2,450,687	398,949	2,849,636		
Pension Asset	32,273,532	5,253,831	37,527,363		
Regulatory Asset	33,139,179	2,049,730	35,188,909		
Regulatory Asset - Accrued Vacation	831,940	135,432	967,372		
Renewable Energy Credits	2,273,845	—	2,273,845		
Unamortized Loss on Reacquired Debt	756,482	123,148	879,630		
<b>Total</b>	<b>\$ 77,820,634</b>	<b>\$ 8,953,294</b>	<b>\$ 86,773,928</b>		

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
<b>OTHER REGULATORY LIABILITIES (Account 254)</b>			
<p>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.</p>			
<b>DEBITS</b>			

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Account Credited (c)	Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	SFAS 109 Regulatory Liability: Electric	271,274,846	Various	28,259,614		243,015,232
2	SFAS 109 Regulatory Liability: Gas	33,593,435	Various	3,139,957		30,453,478
3	Maryland SOS: Energy		Various	13,771,529	14,448,369	676,840
4	Maryland SOS: Transmission		Various	1,524,775	1,524,775	
5	Delaware SOS: Energy		Various	20,186,579	20,186,579	
6	Delaware SOS: Transmission		Various	1,547,523	1,799,327	251,804
7	Delaware SOS: Administrative Costs		Various	5,878,921	7,182,043	1,303,122
8	DE Qualified Fuel Cell Facility	5,397,179	Various	307,870	1,908,008	6,997,317
9	DE Renewable Portfolio Surcharge Deferral	9,580,095	Various	53,678,596	44,098,501	
10	DE Deferred Fuel Costs-Gas	6,600,127	Various	22,970,653	29,714,214	13,343,688
11	DE Distribution Rate Reserve		N/A		9,391,143	9,391,143
12	DE Gas Rate Reserve	622,491	Various	1,124,697	502,206	
13	MD Dynamic Pricing - Critical Peak Rebate Credits	545,111	407.3	295,880	84,383	333,614
14	Tax Cuts and Jobs Act	1,691,512	182.3	11,627	4,117,264	5,797,149
15	DSM Direct Load Control Program-MD	769,449	407.3	1,793,284	1,295,213	271,378
16	DSM-Energy Efficiency Products-MD	1,767,148	407.3	6,241,725	6,323,296	1,848,719
17	MD Bill Stabilization Adjustment Deferral	5,589,623	Various	70,416,232	67,104,737	2,278,128
18	SOS Deferral for FERC 494 Settlement	1,387,728	407.3	524,123	4,338	867,943
19	DE DSM - Energy Efficiency	114,052	908	14,652,855	14,759,129	220,326
20	Transmission Service Revenue	1,453,065	Various	29,126,479	27,673,414	
21	DE Incremental COVID-19 Cost	2,961,668	N/A			2,961,668
22	MD Incremental COVID-19 Cost	172,649	426.5	214,696		(42,047)
23	Chestertown Substation Land Gain	20,692	421.1	20,692		
24	PHISCO Gross Receipt Settlement	410,263	407.3	410,263		
25	Ocean City MD Land Swap Gain		N/A		1,680,060	1,680,060
26	MD Third Party Supplier Recovery		182.3	4,652,588	4,918,532	265,944
27	MD Multi-Year Plan Reconciliation		N/A		6,539,919	6,539,919
41	TOTAL	343,951,133		280,751,158	265,255,450	328,455,425

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:

Line No.	Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism
3	Maryland SOS: Energy	MDPSC Case No. 8908
4	Maryland SOS: Transmission	MDPSC Case No. 8908
5	Delaware SOS: Energy	DEPSC Docket No. 04-391
6	Delaware SOS: Transmission	DEPSC Docket No. 04-391
7	Delaware SOS: Administrative Costs	DEPSC Docket No. 04-391
8	DE Qualified Fuel Cell Facility	DEPSC Docket No. 12-173-04
9	DE Renewable Portfolio Surcharge Deferral	DEPSC Regulation Docket No. 56

10	DE Deferred Fuel Costs-Gas	DEPSC Docket No. 19-0556
11	DE Distribution Rate Reserve	DEPSC Docket No. 22-0897
12	DE Gas Rate Reserve	DEPSC Docket No. 22-0002
13	MD Dynamic Pricing - Critical Peak Rebate Credits	MDPSC Case No. 9156
14	Tax Cuts and Jobs Act	MDPSC Case No. 9473, MDPSC Case No. 9630
15	DSM Direct Load Control Program-MD	MDPSC Case No. 9156
16	DSM-Energy Efficiency Products-MD	MDPSC Case No. 9156
17	MD Bill Stabilization Adjustment Deferral	MDPSC Case No. 9092, MDPSC Case No. 9093
18	SOS Deferral for FERC 494 Settlement	FERC Docket No. EL05-121-009
19	DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985
20	Transmission Service Revenue	FERC Docket No. ER05-515
21	DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286
22	MD Incremental COVID-19 Cost	MDPSC Case No. 9670
23	Chestertown Substation Land Gain	MDPSC Case No. 9630
24	PHISCO Gross Receipt Settlement	MDPSC Case No. 9681
26	MD Third Party Supplier Recovery	MDPSC Maillog 116829
27	MD Multi-Year Plan Reconciliation	MD Case 9681

DPL amortizes its regulatory liabilities in account 254 based on the following amortization periods:

Line No.	Description of Other Regulatory Liabilities	Amortization Lives
18	SOS Deferral for FERC 494 Settlement	10 years
22	MD Incremental COVID-19 Cost	5 years
23	Chestertown Substation Land Gain	3 years
24	PHISCO Gross Receipt Settlement	One-time refund

**(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	7,832,152	recorded to account 190
	1,874,888	recorded to account 282
	18,552,574	recorded to account 410/411
\$	28,259,614	Total

**(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	870,239	recorded to account 190
	208,321	recorded to account 282
	2,061,397	recorded to account 410/411
\$	3,139,957	Total

**(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	10,271,017	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Energy line 25, pg. 232
	3,500,512	recorded to account 407.3
\$	13,771,529	Total

**(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	1,309,376	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Transmission line 26, pg. 232
	215,399	recorded to account 407.3
\$	1,524,775	Total

**(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	12,462,379	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Energy line 21, pg. 232
	7,724,200	recorded to account 407.3
\$	20,186,579	Total

**(g) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	1,543,806	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Transmission line 22, pg. 232
	3,717	recorded to account 407.3
\$	1,547,523	Total

**(h) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following describes the balance sheet reclass:

\$	5,316,871	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Administrative Costs line 23, pg. 232
	562,050	recorded to account 407.3
\$	5,878,921	Total

**(i) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following describes the balance sheet reclass:

\$	270,878	recorded to account 144 - Reclass of reserve on DE Qualified Fuel Cell activity
	36,992	recorded to account 407.3
\$	307,870	Total

**(j) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	42,961,685	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Renewable Portfolio Surcharge Deferral line 4, pg. 232
	10,716,911	recorded to account 407.3
\$	53,678,596	Total

**(k) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":

\$	101,422	recorded to account 173 - Unbilled Gas Cost Rate revenue activity
	965,653	recorded to account 431
	21,903,578	recorded to account 805.1
\$	22,970,653	Total

**(l) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment**

The following are the individual components of "Various":	
\$	20,098 recorded to account 431
	903,474 recorded to account 480
	95,780 recorded to account 481
	105,345 recorded to account 489
\$	1,124,697 Total
<b>(m)</b> Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment	
The following are the individual components of "182.3":	
\$	11,627 recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Tax Cuts and Jobs Act line 29, pg. 232
<b>(n)</b> Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment	
The following are the individual components of "Various":	
\$	16,553,297 recorded to account 456
	53,862,935 recorded to account 182.3 - Reclass of billed surcharge activity, included in MD Bill Stabilization Adjustment Deferral line 8, pg. 232
\$	70,416,232 Total
<b>(o)</b> Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment	
The following are the individual components of "Various":	
\$	28,170,483 recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue line 3, pg. 232
	955,996 recorded to account 456.1
\$	29,126,479 Total
<b>(p)</b> Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment	
The following are the individual components of "182.3":	
\$	4,652,588 recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in MD Third Party Supplier Recovery line 9, pg. 232

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Electric Operating Revenues

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	826,739,223	749,715,964	5,131,740	5,445,976	483,949	479,551
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	348,388,261	343,035,214	5,002,290	5,160,394	64,948	64,479
5	Large (or Ind.) (See Instr. 4)	24,383,548	29,296,177	1,420,472	1,452,063	254	268
6	(444) Public Street and Highway Lighting	15,506,920	14,573,086	43,724	43,794	594	599
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,215,017,952	1,136,620,441	11,598,226	12,102,227	549,745	544,897
11	(447) Sales for Resale	10,967,520	22,705,465	446,324	356,069		
12	TOTAL Sales of Electricity	1,225,985,472	1,159,325,906	12,044,550	12,458,296	549,745	544,897
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,225,985,472	1,159,325,906	12,044,550	12,458,296	549,745	544,897
15	Other Operating Revenues						
16	(450) Forfeited Discounts	3,407,772	2,355,260				
17	(451) Miscellaneous Service Revenues	917,558	263,891				

18	(453) Sales of Water and Water Power					
19	(454) Rent from Electric Property	7,751,138	5,698,343			
20	(455) Interdepartmental Rents					
21	(456) Other Electric Revenues	13,835,400	10,359,133			
22	(456.1) Revenues from Transmission of Electricity of Others	233,818,525	192,537,781			
23	(457.1) Regional Control Service Revenues					
24	(457.2) Miscellaneous Revenues					
25	Other Miscellaneous Operating Revenues					
26	TOTAL Other Operating Revenues	259,730,393	211,214,408			
27	TOTAL Electric Operating Revenues	1,485,715,865	1,370,540,314			

Line 12, column (b) includes \$ 725,669 of unbilled revenues.  
Line 12, column (d) includes (83,843) MWH relating to unbilled revenues

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FOOTNOTE DATA

<b>(a) Concept: MiscellaneousServiceRevenues</b>	
Items greater than \$250,000 Connect Charges	\$ 721,945
<b>(b) Concept: OtherElectricRevenue</b>	
Amounts over \$250,000	
Intercompany Revenue	\$ 6,020,053
MD Calendar Revenue Normalization	1,909,419
MD Bill Stabilization Adjustment	1,402,286
Price Responsive Demand Credit	1,245,775
Intracompany Power Sales	1,186,736
Intercompany Power Sales	730,592
Bonus Performance	375,150
RPM Seasonal Capacity Performance Auction	273,748
License Agreement Fees	269,092
MD Interconnection Fees	(481,775)
<b>(c) Concept: OtherElectricRevenue</b>	
Amounts over \$250,000	
Intercompany Revenue	\$ 3,934,974
Price Responsive Demand Credit	3,234,096
RPM Seasonal Capacity Performance Auction	1,549,596
Intracompany Power Sales	1,148,425
Auction Revenue Rights	982,628
Intercompany Power Sales	790,150
RPM Auction	532,779
Consolidated Billing and Account Management Fees	447,403
Transmission Losses	314,904
MD Bill Stabilization Adjustment	(466,679)
MD Calendar Revenue Normalization	(2,445,539)

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					

6					
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38					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
<b>SALES OF ELECTRICITY BY RATE SCHEDULES</b>			

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales					
2	Residential	4,063,398	680,846,378	395,862	10,265	0.1676
3	Residential Time Of Use - Non Demand	1,283	184,730	110	11,649	0.1439
4	Outdoor Lighting - Residential	6,494	2,272,252	4,204	1,545	0.3499
5	Residential Space Heating	1,024,099	144,552,162	87,433	11,713	0.1412
6	Residential Time-of-Use (TOU) Pilot	5,288	968,454	520	10,169	0.1831
7	Plug in Vehicle - Residential	299	50,008	31	9,777	0.1672
8	Small General Service		(303)			
9	Medium General Service					
10	Unbilled Revenue	(33,103)	785,538			(0.0237)
11	DE Interim rates subject to refund		(5,819,380)			
12	DE DSIC revenue subject to refund					
13	Adjustments - Duplicate Customers			(4,211)		
14	Energy Credits		(1,883,616)			
15	NEM Billed Adjustments	63,982	4,783,000			0.0748
41	TOTAL Billed Residential Sales	5,164,843	825,953,685	483,949	10,672	0.1599
42	TOTAL Unbilled Rev. (See Instr. 6)	(33,103)	785,538			(0.0237)
43	TOTAL	5,131,740	826,739,223	483,949	10,604	0.1611

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**SALES OF ELECTRICITY BY RATE SCHEDULES**

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	442 - Commercial					
2	Small General Service	1,028,672	137,530,807	53,916	19,079	0.1337
3	Unmetered Small General Service	336	84,221	219	1,537	0.2507
4	Separately Metered Space Heating	69,923	5,603,178	2,298	30,424	0.0801
5	Separately Metered Water Heating	551	58,013	98	5,635	0.1052
6	Medium General Service	1,146,277	92,038,014	8,690	131,909	0.0803
7	Unmetered Medium General Service	36	18,041	15	2,411	0.4989
8	Large General Service	786,899	37,291,078	549	1,434,639	0.0474
9	General Services Primary	1,960,744	64,026,122	570	3,438,897	0.0327
10	Commercial Outdoor Lighting	11,921	4,660,900	3,772	3,160	0.3910
11	Commercial Outdoor Recreational Lighting	1,090	179,550	75	14,471	0.1647

12	Telecommunications Network Svc	3,566	271,960	924	3,860	0.0763
13	Residential			0		
14	Unbilled Revenue	(23,103)	350,944			(0.0152)
15	DE Interim rates subject to refund		(2,807,729)	0		
16	DE DSIC revenue subject to refund			0		
17	Public Utility Tax Surcharge Revenue		8,153,521			
18	Adjustments - Duplicate Customers			(6,178)		
19	Energy Credits & Billed BSA		(209,860)	0		
20	Company Owned Charging Stations and (Manual Adjustment)	171	36,501	0		0.2130
21	NEM Billed Adjustments	15,207	1,103,000	0		0.0725
41	TOTAL Billed Small or Commercial	5,025,393	348,037,317	64,948	77,376	0.0693
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(23,103)	350,944			(0.0152)
43	TOTAL Small or Commercial	5,002,290	348,388,261	64,948	77,020	0.0696

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**SALES OF ELECTRICITY BY RATE SCHEDULES**

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	(442) Industrial					
2	Small General Service	5,184	574,560	96	54,282	0.1108
3	Medium General Service	7,054	486,242	36	197,319	0.0689
4	Large General Service	32,315	1,463,438	18	1,762,660	0.0453
5	General Services Primary	776,850	16,671,033	95	8,141,657	0.0215
6	General Services Transmission	574,426	2,845,056	9	64,421,583	0.0050
7	Industrial Outdoor Lighting	287	69,556	45	6,461	0.2424
8	Separately Metered Space Heating	(90)	(1,989)		(539,412)	0.0221
9	NEM Billed Adjustments	21	1,100			0.0529
10	Unbilled Revenue	(27,182)	(262,366)			0.0097
11	DE Interim rates subject to refund		(270,287)			
12	DE DSIC revenue subject to refund					
13	Public Utility Tax Surcharge Revenue		438,767			
14	Adjustments - Duplicate Customers			(45)		
15	Energy Credits					
16	Indian River Retroactive Billing	51,607	2,368,438			0.0459
41	TOTAL Billed Large (or Ind.) Sales	1,447,654	24,645,914	254	5,701,295	0.0170
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(27,182)	(262,366)			0.0097
43	TOTAL Large (or Ind.)	1,420,472	24,383,548	254	5,594,245	0.0172

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**SALES OF ELECTRICITY BY RATE SCHEDULES**

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 - Public Street & Highway Lght					
2	Outdoor Lighting	44,179	15,900,732	594	74,364	0.3599
3	DE Interim rates subject to refund		(278,088)			
4	DE DSIC revenue subject to refund					
5	Unbilled Revenue	(455)	(148,447)			0.3264
6	Public Utility Tax Surcharge Revenue		32,723			
41	TOTAL Billed Public Street and Highway Lighting	44,179	15,655,367	594	74,375	0.3544
42	TOTAL Unbilled Rev. (See Instr. 6)	(455)	(148,447)			0.3264
43	TOTAL	43,724	15,506,920	594	73,599	0.3547

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**SALES OF ELECTRICITY BY RATE SCHEDULES**

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	11,682,069	1,214,292,283	549,746	21,250	0.1039
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(83,843)	725,669			(0.0087)
43	TOTAL - All Accounts	11,598,226	1,215,017,952	549,746	21,097	0.1048

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**SALES FOR RESALE (Account 447)**

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

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

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

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

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

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

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 (g) 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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	PECO Energy	RQ	2				804		39,220		39,220
2	PJM Interconnection	OS	PJM				445,520		10,928,300		10,928,300
15	Subtotal - RQ						804		39,220		39,220
16	Subtotal-Non-RQ						445,520		10,928,300		10,928,300
17	Total						446,324		10,967,520		10,967,520

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**ELECTRIC OPERATION AND MAINTENANCE EXPENSES**

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
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 (Enter Total of 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-Nuclear. Power (Enter Total of 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 (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		

64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
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 Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	592,123,186	571,650,949
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	(17,091)	55,381
78	(557) Other Expenses	32,087,370	26,867,597
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	624,193,465	598,573,927
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	624,193,465	598,573,927
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,014,865	8,332,779
85	(561.1) Load Dispatch-Reliability	120,018	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	537,686	601,853
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,527	70,069
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	(3,232)	19,182
93	(562) Station Expenses		
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	76,605	
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	4,127,914	2,300,955
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	13,878,383	11,324,838
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		6,678
102	(569) Maintenance of Structures	707,481	500,143
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		

106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	9,442,637	7,868,351
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	4,486,981	4,428,190
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	388,842	383,922
111	TOTAL Maintenance (Total of Lines 101 thru 110)	15,025,941	13,187,284
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	28,904,324	24,512,122
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	9,344	64,371
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	9,344	64,371
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	9,344	64,371
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,331,874	1,579,599
135	(581) Load Dispatching	3,548,573	3,273,053
136	(582) Station Expenses	125,419	1,629
137	(583) Overhead Line Expenses	2,657,085	1,017,580
138	(584) Underground Line Expenses	2,551,098	2,690,603
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	407,211	322,924
140	(586) Meter Expenses	3,901,067	4,248,917
141	(587) Customer Installations Expenses	540,377	634,823
142	(588) Miscellaneous Expenses	21,005,994	18,726,067
143	(589) Rents	1,961,655	1,584,531
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	38,030,353	34,079,726
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		2,939
147	(591) Maintenance of Structures	499,645	482,050
148	(592) Maintenance of Station Equipment	5,002,594	5,128,966
148.1	(592.2) Maintenance of Energy Storage Equipment		

149	(593) Maintenance of Overhead Lines		48,364,196	45,053,682
150	(594) Maintenance of Underground Lines		3,559,774	4,290,930
151	(595) Maintenance of Line Transformers		692,690	798,422
152	(596) Maintenance of Street Lighting and Signal Systems		1,788,474	1,785,081
153	(597) Maintenance of Meters		1,099,217	523,366
154	(598) Maintenance of Miscellaneous Distribution Plant		1,029,791	865,580
155	TOTAL Maintenance (Total of Lines 146 thru 154)		62,036,381	58,931,016
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		100,066,734	93,010,742
157	5. CUSTOMER ACCOUNTS EXPENSES			
158	Operation			
159	(901) Supervision			
160	(902) Meter Reading Expenses		1,093,654	888,243
161	(903) Customer Records and Collection Expenses		49,426,177	45,087,455
162	(904) Uncollectible Accounts		8,992,800	10,314,159
163	(905) Miscellaneous Customer Accounts Expenses			
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)		59,512,631	56,289,857
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
166	Operation			
167	(907) Supervision			
168	(908) Customer Assistance Expenses		11,430,301	10,992,924
169	(909) Informational and Instructional Expenses		132,845	156,985
170	(910) Miscellaneous Customer Service and Informational Expenses		152,536	
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)		11,715,682	11,149,909
172	7. SALES EXPENSES			
173	Operation			
174	(911) Supervision			
175	(912) Demonstrating and Selling Expenses			
176	(913) Advertising Expenses			
177	(916) Miscellaneous Sales Expenses			
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)			
179	8. ADMINISTRATIVE AND GENERAL EXPENSES			
180	Operation			
181	(920) Administrative and General Salaries		2,572,698	3,224,138
182	(921) Office Supplies and Expenses		5,300,525	5,271,821
183	(Less) (922) Administrative Expenses Transferred-Credit			
184	(923) Outside Services Employed		71,844,572	72,230,523
185	(924) Property Insurance		660,521	692,197
186	(925) Injuries and Damages		264,868	2,424,052
187	(926) Employee Pensions and Benefits		11,023,583	6,484,747
188	(927) Franchise Requirements			
189	(928) Regulatory Commission Expenses		2,068,028	2,095,257
190	(929) (Less) Duplicate Charges-Cr.			
191	(930.1) General Advertising Expenses		549,663	586,529
192	(930.2) Miscellaneous General Expenses		7,127,767	6,987,014
193	(931) Rents			

194	TOTAL Operation (Enter Total of Lines 181 thru 193)	101,412,225	99,996,278
195	Maintenance		
196	(935) Maintenance of General Plant	1,113,991	(80,103)
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	102,526,216	99,916,175
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	926,928,396	883,517,103

FERC FORM NO. 1 (ED. 12-93)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**PURCHASED POWER (Account 555)**

- Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
- Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:  
  
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.  
  
 LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.  
  
 IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.  
  
 SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.  
  
 LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.  
  
 IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.  
  
 EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.  
  
 OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.  
  
 AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
- In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
- Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
- The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)	
1	PJM Interconnection, LLC	EX	PJM Tariff				40,948					245,682	2,299,952	89,201,260	91,746,894
2	AEP Energy Partners, Inc.	OS					50,736						2,946,019		2,946,019
3	Axpo U.S. LLC	OS					562,266						29,283,907		29,283,907
4	Constellation Energy Resources, LLC	OS					1,219,492						84,337,007		84,337,007
5	DTE Energy Trading, Inc.	OS					1,065,854						76,595,780		76,595,780
6	Hartree Partners, LP	OS					1,717,927						115,209,399		115,209,399
7	Next Era Energy Power Marketing, LLC	OS					1,068,171						73,310,033		73,310,033
8	Shell Energy North America US, LP	OS					231,618						22,440,809		22,440,809
9	TransAlta Energy Marketing (U.S.)	OS					365,714						19,442,744		19,442,744





1	PJM Point to Point Trans Revenue	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	OATT									697,656	697,656
2	PJM Trans Owner Sched, Sys Control													1,429,441	1,429,441
3	PJM Network Integration Transmission Svc													226,456,992	226,456,992
4	Other Transmission Agreements													3,467,952	3,467,952
5	PJM Transmission Enhancement Credits													1,766,484	1,766,484
6	AEP Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		103,862						
7	Alpha Gas and Electric, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		606						
8	Ambit Energy (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,752						
9	Ambit Energy (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,569						
10	American Power & Gas of MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,307						
11	Astral Energy LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		27						
12	Atlantic Energy MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,677						
13	Atlantic Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,808						
14	BOC Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		188,264						
15	Brookfield Renewable Energy Marketing US LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		10,359						
16	Calpine Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		211,852						
17	Champion Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		47,699						
18	CleanChoice Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		38,066						
19	Clearview Electric (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,052						
20	Clearview Electric (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,601						
21	Commerce Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		33,355						
22	Constellation NewEnergy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,732,404						
23	CPV Retail Energy LP	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,854						
24	Direct Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		647,344						
25	Discount Energy Group LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		205						
26	Discount Power, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,573						
27	EDF Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		125,767						
28	ELIGO	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		837						
29	Energy Harbor	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		12,126						
30	Energy Plus Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,336						
31	Engie Resources	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		283,647						
32	First Point Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		391						

33	Freepoint Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		162,440					
34	GEXA Energy Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		218,849					
35	GEXA Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		14,052					
36	Great American Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,008					
37	Green Mountain Energy Company (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		454					
38	Greenlight Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		490					
39	Horizon Power & Light LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,776					
40	Hudson Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,988					
41	IDT Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,571					
42	Indra Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,879					
43	Inspire Energy Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		51,085					
44	Kuehne Chemical Co	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		76,761					
45	Major Energy Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,819					
46	Maryland Gas & Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,197					
47	MidAmerican Energy Services, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		110,973					
48	MP2 Energy NE LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		50,425					
49	NextEra Energy Services Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,266					
50	NextEra Energy Services Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		233					
51	Nordic Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		37					
52	Park Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,056					
53	PBF Power Marketing, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		309,995					
54	Plymouth Rock Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		373					
55	Public Power of MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		11,830					
56	Reliant Energy Northeast LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		88,332					
57	Residents Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		11,401					
58	RPA Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,378					
59	Rushmore Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		24,642					
60	SFE Energy Maryland, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,412					
61	SmartEnergy Holdings, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		19,983					
62	SmartEnergy Holdings, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,473					
63	SmartestEnergy US LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		41,180					
64	Spark Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL	DPL		1,583					

						SYSTEM	SYSTEM							
65	StateWise Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		261					
66	Stream Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,525					
67	Stream Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,876					
68	SunSea	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		116					
69	Texas Retail Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		29,308					
70	Titan Gas, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,516					
71	Tomorrow Energy Corp	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,199					
72	UGI Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		20,422					
73	Viridian Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,283					
74	Washington Gas Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		917,058					
75	XOOM Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,213					
76	XOOM Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		8,605					
35	TOTAL								5,717,663				233,818,525	233,818,525

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

<b>(a)</b> Concept: OtherChargesRevenueTransmissionOfElectricityForOthers DPL share of PJM pool Point-to-Point transmission revenue from the administration of the PJM Interconnection, LLC Open Access Transmission Tariff (OATT).
<b>(b)</b> Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Revenue from PJM Interconnection, LLC for Transmission Owner Scheduling, System Control and Dispatch Service with the DPL Zone Control Center.
<b>(c)</b> Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Revenue from the PJM Interconnection, LLC for Network Integration Transmission Service and Other Supporting Facilities, specifically, ODEC and DEMEC with DPL.
<b>(d)</b> Concept: OtherChargesRevenueTransmissionOfElectricityForOthers 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.
<b>(e)</b> Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Revenue from Transmission Enhancements.

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4		
<b>TRANSMISSION OF ELECTRICITY BY ISO/RTOs</b>					
<ol style="list-style-type: none"> <li>Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.</li> <li>Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).</li> <li>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.</li> <li>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.</li> <li>In column (d) report the revenue amounts as shown on bills or vouchers.</li> <li>Report in column (e) the total revenues distributed to the entity listed in column (a).</li> </ol>					
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				
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49				
40	TOTAL			

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**TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)**

- Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
- In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
- In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:  
FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. 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.
- Enter "TOTAL" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		0	0	0	0	0	0

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**MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)**

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	430,362
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	

6	Trustee Fees	212,089
7	Board of Director Expenses	96,973
8	Research, Development and Demonstration, including Memberships	654
9	DE Environmental & Low Income and MD Universal Fund	6,307,096
10	Credit card accruals	77,917
11	Miscellaneous	2,676
46	TOTAL	7,127,767

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**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**

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

**A. Summary of Depreciation and Amortization Charges**

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			11,770,351		11,770,351
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	66,991,384				66,991,384
8	Distribution Plant	90,044,259				90,044,259
9	Regional Transmission and Market Operation					
10	General Plant	15,943,251				15,943,251
11	Common Plant-Electric	4,575,175		10,647,335		15,222,510
12	TOTAL	177,554,069		22,417,686		199,971,755

**B. Basis for Amortization Charges**

Consistent with the preceding year, electric and common intangible Plant computer Software is amortized for a five year period using a straight line basis.

**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	33,659	75 years		0.87	R3	
14	352	90,643	70 years	(20)	1.66	R2	
15	353	711,034	42 years	(25)	3.52	S0.5	
16	354	73,959	75 years	(45)	1.39	R3	
17	355	643,336	43 years	(75)	4.27	R2.5	
18	356	373,778	55 years	(75)	3.47	R2	
19	357	6,527	60 years		1.26	R4	

20	358	63,077	55 years	(10)	1.9	R3	
21	359	1,111	65 years		0.54	R4	
22	SUBTOTAL	1,997,124					
23	Distribution						
24	360.2 DE	3,584	70 years		1.05	R4	
25	360.2 MD	4,086	60 years		1.07	R2	
26	361 DE	28,695	65 years	(10)	1.27	R4	
27	361 MD	31,862	60 years	(15)	1.78	R1.5	
28	362 DE	282,718	45 years	(20)	2.08	R2	
29	362 MD	231,630	45 years	(25)	2.59	R1.5	
30	364 DE	146,693	55 years	(100)	2.25	R2	
31	364 MD	142,399	55 years	(125)	2.94	R2	
32	365 DE	242,549	55 years	(100)	1.53	R1.5	
33	365 MD	269,898	57 years	(100)	2.23	R0.5	
34	366 DE	25,406	70 years	(5)	0.84	S3	
35	366 MD	1,020	55 years		1.25	R3	
36	367 DE	270,952	52 years	(40)	1.82	R3	
37	367 MD	214,405	48 years	(20)	2.29	R3	
38	368 DE	368,942	45 years	(50)	1.77	R2	
39	368 MD	309,406	36 years	(50)	3.61	R1	
40	369.1 DE	20,380	65 years	(120)	0.81	R4	
41	369.1 MD	8,999	65 years	(75)	2.73	R4	
42	369.2 DE	112,711	55 years	(60)	1.36	S3	
43	369.2 MD	95,689	50 years	(25)	1.88	R4	
44	370 DE	14,884	25 years	(3)	2.77	L0.5	
45	370 MD	7,385	30 years		2.19	R1	
46	370.1 DE	72,619	15 years	(3)	8.13	S2	
47	370.1 MD	44,627	10 years		14.64	S3	
48	371.1 MD	2,921	15 years		6.84	S3	
49	371.2 DE	30,104	18 years	(40)	8.2	R2	
50	371.2 MD	11,292	45 years	(50)	2.73	R3	
51	373 DE	73,522	38 years	(30)	0.95	R2	
52	373 MD	17,640	30 years	(30)	5.1	L0.5	
53	SUBTOTAL	3,087,018					
54	GENERAL						
55	390 DE	13,420	50 years	(10)	1.01	R3	
56	390 MD	44,360	35 years	(10)	3.43	S0	
57	391.1 DE	2,969	19 years		5.65	L2	
58	391.1 MD	1,898	15 years		5.78	SQ	
59	391.3 MD	2,801	10 years		10.14	SQ	
60	391.3 DE	11,077	5 years		21.49	SQ	
61	393 DE	233	40 years		19.74	R4	
62	394 DE	12,772	25 years		6.56	SQ	
63	394 MD	12,576	15 years		7.19	SQ	
64	395 DE		20 years		15.46	SQ	
65	397 MD	35,818	30 years	(10)	3.32	S2.5	



7	2021 MD Base Rate Case 9670		60,727	60,727		Electric	928	17,718		928	43,008
8	2022 MD MYP 9681		234,186	234,186		Electric	928	38,519		928	195,667
9	General Regulation Legal		178,510	178,510		Electric	928	178,510			
10	PC44 DPL MD		(6,269)	(6,269)		Electric	928	(6,269)			
11	2019 MD Base Rate Case 9630		23,795	23,795		Electric	928			928	23,795
12	Transmission:										
13	ER05-515 Annual Rate Updates - FERC Transmission		268,139	268,139		Electric	928	268,139			
14	ER21-205 Order No. 864 Compliance		8,856	8,856		Electric	928	8,856			
15	ER21-2965 - Transmission Wages and Salary (W&S) Allocator		55,581	55,581		Electric	928	55,581			
16	ER22-2201 Transmission Depreciation Rates		5,007	5,007		Electric	928	5,007			
46	TOTAL		2,068,028	2,068,028				1,805,557			262,470

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**RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES**

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

2. Indicate in column (a) the applicable classification, as shown below:  
Classifications:

Electric R, D and D Performed Internally:

Generation

hydroelectric

Recreation fish and wildlife  
Other hydroelectric

Fossil-fuel steam  
Internal combustion or gas turbine  
Nuclear  
Unconventional generation  
Siting and heat rejection

Transmission

Overhead  
Underground

Distribution  
Regional Transmission and Market Operation  
Environment (other than equipment)  
Other (Classify and include items in excess of \$50,000.)  
Total Cost Incurred

Electric, R, D and D Performed Externally:

Research Support to the electrical Research Council or the Electric Power Research Institute  
Research Support to Edison Electric Institute  
Research Support to Nuclear Power Groups  
Research Support to Others (Classify)  
Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""

7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B-1	Membership - EPRI		169,190	Various	169,190	
2	B-4	Membership - NEETRAC (Georgia Tech Research Corp)		10,616	Various	10,616	

3	B-4	Membership - Electric Drive Transportation Association		5,390	Various	5,390
4	B-4	Membership - Centre for Energy Advancement through Technical Innovation		17,977	Various	17,977
5	B-4	Membership - Watson & Renner		5,088	Various	5,088
6	B-5	Patent Legal Fees		654	930.2	654
7	Total			208,915		208,915

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FOOTNOTE DATA			

<b>(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts</b>			
Membership - EPRI:			
<b>FERC</b>	<b>Amount</b>		
588		89,671	
566		79,519	
Total	\$	169,190	
<b>(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts</b>			
Membership - NEETRAC (Georgia Tech Research Corp):			
<b>FERC</b>	<b>Amount</b>		
588	\$	5,414	
566		5,202	
Total	\$	10,616	
<b>(c) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts</b>			
Membership - Electric Drive			
<b>FERC</b>	<b>Amount</b>		
588	\$	2,695	
566		2,695	
Total	\$	5,390	
<b>(d) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts</b>			
Membership - CEATI			
<b>FERC</b>	<b>Amount</b>		
588	\$	2,517	
566		15,460	
Total	\$	17,977	
<b>(e) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts</b>			
Membership - Watson & Renner			
<b>FERC</b>	<b>Amount</b>		
588	\$	2,544	
566		2,544	
Total	\$	5,088	

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**DISTRIBUTION OF SALARIES AND WAGES**

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	25,422		
4	Transmission	781,592		
5	Regional Market			
6	Distribution	14,039,312		
7	Customer Accounts	1,587,660		

8	Customer Service and Informational	1,803,757		
9	Sales			
10	Administrative and General	2,740,110		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	20,977,853		
12	Maintenance			
13	Production			
14	Transmission	4,108,098		
15	Regional Market			
16	Distribution	15,300,436		
17	Administrative and General	70,295		
18	TOTAL Maintenance (Total of lines 13 thru 17)	19,478,829		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	25,422		
21	Transmission (Enter Total of lines 4 and 14)	4,889,690		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	29,339,748		
24	Customer Accounts (Transcribe from line 7)	1,587,660		
25	Customer Service and Informational (Transcribe from line 8)	1,803,757		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	2,810,405		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	40,456,682	2,053,091	42,509,773
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	460,693		
34	Storage, LNG Terminaling and Processing	744,043		
35	Transmission	984,572		
36	Distribution	5,918,323		
37	Customer Accounts	341,712		
38	Customer Service and Informational	121,569		
39	Sales			
40	Administrative and General	277,351		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	8,848,263		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	43,843		
47	Transmission	339,868		
48	Distribution	1,242,419		
49	Administrative and General	5,445		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	1,631,575		
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)	460,693		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	787,886		
56	Transmission (Lines 35 and 47)	1,324,440		
57	Distribution (Lines 36 and 48)	7,160,742		
58	Customer Accounts (Line 37)	341,712		
59	Customer Service and Informational (Line 38)	121,569		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	282,796		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	10,479,838	320,369	10,800,207
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	50,936,520	2,373,460	53,309,980
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	53,702,261	3,156,900	56,859,161
69	Gas Plant	9,001,575	394,387	9,395,962
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	62,703,836	3,551,287	66,255,123
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,739,629	367,762	5,107,391
74	Gas Plant	468,144	24,984	493,128
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,207,773	392,746	5,600,519
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Expenses from Merchandising, Jobbing & Contract Work - 416	170,178	8,346	178,524
80	Expenses of Non-Utility Operations - 417.1	10,302	583	10,885
81	Donations - 426.1	24,481	1,393	25,874
82	Exp. For Certain Civic, Political & Related Activities - 426.4	73,271	2,888	76,159
83	Other Deductions - 426.5	38,020	1,495	39,515
84	Plant Held for Future -105	2,929		2,929
85	Other Deferred Credits-253	19,727		19,727
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	338,908	14,705	353,613
96	TOTAL SALARIES AND WAGES	119,187,037	6,332,198	125,519,235

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: SalariesAndWagesElectricTransmission

Exelon Business Services Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 21 of this schedule total \$4,134,699 for full-year 2023.

PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 21 of this schedule total \$838,785 for full-year 2023.

(b) Concept: SalariesAndWagesElectricAdministrativeAndGeneral

Exelon Business Services Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 27 of this schedule total \$8,159,995 for full-year 2023.

PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 27 of this schedule total \$10,792,430 for full-year 2023.

(c) Concept: SalariesAndWagesElectricOperationAndMaintenance

Exelon Business Services Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 28 of this schedule total \$14,132,007 for full-year 2023.

PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 28 of this schedule total \$29,951,077 for full-year 2023.

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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 Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- 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 the 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	71,411,536	1,631,624	(26,544)	—	73,016,616
389.1	1,621,110	—	—	—	1,621,110
390.3	69,485,795	4,460,825	(2,010,551)	—	71,936,070
391.1	5,599,606	—	(210,485)	—	5,389,121
391.3	15,570,530	561,073	(33,427)	—	16,098,176
393	—	—	—	—	—
394	5,221,555	—	—	—	5,221,555
397	25,171,457	490,743	—	—	25,662,200
398	10,782,998	696,313	—	—	11,479,311
Grand Total	\$ 205,601,087	\$ 7,840,576	\$ (2,281,007)	\$ —	\$ 211,160,659

Acct	Total Common			E = 83.47%	G = 16.53%
	Electric	Gas	Utility Plant		
301	\$ 614,757	\$ 121,743	\$ 736,500		
303	60,946,969	12,069,647	73,016,616		
389.1	1,353,141	267,969	1,621,110		
390.3	60,045,038	11,891,032	71,936,070		
391.1	4,498,299	890,822	5,389,121		
391.3	13,437,148	2,661,028	16,098,176		
393	—	—	—		
394	4,358,432	863,123	5,221,555		
397	21,420,238	4,241,962	25,662,200		
398	9,581,781	1,897,530	11,479,311		
	\$ 176,255,803	\$ 34,904,856	\$ 211,160,659		

Accumulated Provision for Depreciation of Common

Utility Plant  
DPL  
12/31/2022

	Total Common	Electric	Gas
Balance at Beginning of Year	82,123,112	67,850,115	14,272,997
Depreciation Provision for the Year Charged to:			
403 Depreciation Expense	5,414,825	4,575,175	839,650
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(2,254,464)	(1,881,801)	(372,663)
Cost of Removal, Net of Salvage	(566,853)	(473,152)	(93,701)
Other Debit or Credit Items:			
Transfers / Adjustments	—	—	—

Gain from Sale	—	—	—
Electric & Gas Allocator Adjustment	—	642,626	(642,626)
Balance at End of Year	84,716,620	70,712,963	14,003,657
<b>Accumulated Provision for Amortization of Common Utility Plant</b>			
DPL 12/31/2022			
	<b>Total Common</b>	<b>Electric</b>	<b>Gas</b>
Balance at Beginning of Year	38,268,401	31,617,353	6,651,048
Depreciation Provision for the Year Charged to:			
404 Amortization Expense	13,009,902	10,647,335	2,362,567
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(26,544)	(22,156)	(4,388)
Cost of Removal, Net of Salvage	—	—	—
Other Debit or Credit Items			
Transfers / Adjustments			
Electric & Gas Allocator Adjustment	—	537,311	(537,311)
Balance at End of Year	51,251,759	42,779,843	8,471,916

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**AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS**

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, 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)	960,046	1,613,377	1,990,163	2,299,952
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(3,328,700)	(5,974,775)	(8,370,770)	(10,928,300)
4	Transmission Rights	21,062,531	42,543,679	65,675,997	89,288,857
5	Ancillary Services	19,492	31,758	74,280	(34,562)
6	Other Items (list separately)				
7	Demand	148,274	205,459	218,734	238,906
8	PJM Customer Payment Default			(1,319)	(1,319)
46	TOTAL	18,861,643	38,419,498	59,587,085	80,863,534

FERC FORM NO. 1 (NEW. 12-05)

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**PURCHASES AND SALES OF ANCILLARY SERVICES**

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff. In columns for usage, report usage-related billing determinant and the unit of measure.

- On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
- On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
- On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
- On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
- On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
- On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	6,840,029	MWH	(1,215)	12,557,692	MWH	1,429,440
2	Reactive Supply and Voltage		MWH	12,573			
3	Regulation and Frequency Response		MWH	5,417			
4	Energy Imbalance						
5	Operating Reserve - Spinning		MWH	1,691			
6	Operating Reserve - Supplement		MWH	1,539			
7	Other		MWH	(61,024)			
8	Total (Lines 1 thru 7)	6,840,029	MWH	(41,019)	12,557,692	MWH	1,429,440

FERC FORM NO. 1 (New 2-04)

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FOOTNOTE DATA

<b>(a)</b> Concept: AncillaryServicesPurchasedNumberOfUnitsPower	
The number of units reported on Line #2, Column (b) is 6,840,029 MWH.	
<b>(b)</b> Concept: AncillaryServicesPurchasedNumberOfUnitsPower	
The number of units reported on Line #2, Column (b) is 6,840,029 MWH.	
<b>(c)</b> Concept: AncillaryServicesPurchasedNumberOfUnitsPower	
The number of units reported on Line #2, Column (b) is 6,840,029 MWH.	
<b>(d)</b> Concept: AncillaryServicesPurchasedNumberOfUnitsPower	
The number of units reported on Line #2, Column (b) is 6,840,029 MWH.	
<b>(e)</b> Concept: AncillaryServicesPurchasedAmount	
<b>Other Ancillary Services Purchased are as follows:</b>	
Balancing Operating Reserve	\$ (61,530)
Non-Synchronized Reserve	486
Reactive Services	20
	\$ (61,024)

FERC FORM NO. 1 (New 2-04)

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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- 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.
- Report on Column (b) by month the transmission system's peak load.
- Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservations (i)	Other Service (j)	
	NAME OF SYSTEM: 0										
1	January	2,926	11	8	2,131	795					
2	February	3,370	4	8	2,596	774					
3	March	2,837	20	8	2,073	764					
4	Total for Quarter 1				6,800	2,333	0	0	0	0	
5	April	2,284	6	19	1,605	679					



15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

FERC FORM NO. 1 (NEW. 07-04)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2023-12-31	Year/Period of Report End of: 2023/ Q4
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**ELECTRIC ENERGY ACCOUNT**

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	11,598,226
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	804
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	445,520
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	14,862
7	Other		27	Total Energy Losses	498,280
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	0	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	12,557,692
10	Purchases (other than for Energy Storage)	6,840,029			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	5,717,663			
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	5,717,663			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	12,557,692			

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**MONTHLY PEAKS AND OUTPUT**

- 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.
- Report in column (b) by month the system's output in Megawatt hours for each month.
- Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
- Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
- Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	1,112,319	32,784	2,926	11	8
30	February	1,002,397	39,257	3,370	4	8

31	March	1,041,147	39,612	2,837	20	8
32	April	881,748	65,973	2,284	6	19
33	May	998,141	147,290	2,364	12	18
34	June	966,562	(9,631)	3,076	26	18
35	July	1,328,417	5,567	4,022	28	18
36	August	1,235,348	21,128	3,725	15	16
37	September	1,031,754	13,054	3,831	7	17
38	October	887,789	23,887	2,429	3	18
39	November	979,366	32,426	2,977	29	8
40	December	1,092,704	34,173	2,818	14	8
41	Total	12,557,692	445,520			

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Name of Respondent: Deimarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

[a] Concept: HourOfMonthlyPeak

This note applies to rows 29 - 40. Amounts reported in Column (f) are presented in Eastern Standard Time (EST), as DPL operations are in that time zone.

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Name of Respondent: Deimarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
<b>Steam Electric Generating Plant Statistics</b>			

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 term basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0
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 (total 13 thru 20)	
18	Cost per KW of Installed Capacity (line 17/5) Including	
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	0
35	Expenses per Net kWh	
35	<b>Plant Name</b>	
36	Fuel Kind	
37	Fuel Unit	
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	

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**Hydroelectric Generating Plant Statistics**

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	<b>Net Plant Capability (in megawatts)</b>	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	<b>Cost of Plant</b>	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	<b>Production Expenses</b>	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

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**Pumped Storage Generating Plant Statistics**

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	<b>Cost of Plant</b>	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	<b>Production Expenses</b>	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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113	Cedar Creek	Clayton	138	138	Wood poles	9.23		1	954 ACSR								
114	Towsend	Church	138	138	Steel poles	12.32		1	636 ACSR								
115	Kiamensi	Milltown	138	138	Wood poles	1.40	1.31	1	954 ACSR								
116	Milltown	Mermaid-Valley Road	138	138	Wood poles	4.60		1	954 ACSR								
117	Valley Road	Hockessin	138	138	Wood poles	1.78		1	954 ACSR								
118	Kiamensi	Hockessin	138	138	Wood poles	6.26		1	954 ACSR								
119	Reybold	Lums Pond	138	138	Wood poles	8.22		1	954 ACSR								
120	Lums Pond	Mt Pleasant	138	138	Wood poles	9.74		1	954 ACSR								
121	Bear	Sunset Lake	138	138	Wood poles	5.31		1	954 ACSR								
122	#2 Glasgow	Mt Pleasant	138	138	Steel poles	11.10		1	1590 ACSR								
123	Carville	Wye Mills	138	138	Steel poles	0.12	7.93	1	1590 ACSR								
124	Piney Grove	Wattsville	138	138	Steel poles	0.71	30.19	1	1590 ACSR								
125	Church	Pondtown	138	138	Steel poles	0.13	7.48	1	1590 ACSR								
126	Motiva	Praxair	138	138	no poles	0.02		1	1590 ACSR								
127	SOLADIGO SOLAR	TOWNSEND	138	138	no poles	0.03		1	795 ACSR								
36	TOTAL					2,655.56	360.32	316		35,400,557.00	1,155,923,339.00	1,191,323,896.00	9,013,902.67	4,486,981.32	239,125.48	13,740,009.47	

FERC FORM NO. 1 (ED. 12-87)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

<b>(a)</b> Concept: LengthForStandAloneTransmissionLines Includes 0.54 miles of steel poles as well.
<b>(b)</b> Concept: LengthForStandAloneTransmissionLines Includes 0.14 miles of UG as well.
<b>(c)</b> Concept: LengthForStandAloneTransmissionLines Includes 954 ACSR as well.
<b>(d)</b> Concept: LengthForStandAloneTransmissionLines Includes 2.76 miles of UG as well.
<b>(e)</b> Concept: LengthForStandAloneTransmissionLines Includes 1.23 miles of UG as well.
<b>(f)</b> Concept: SizeOfConductorAndMaterial Includes 1949 ACSS as well.
<b>(g)</b> Concept: SizeOfConductorAndMaterial Includes 1949 ACSS as well.
<b>(h)</b> Concept: SizeOfConductorAndMaterial Includes KCMIL AL as well.
<b>(i)</b> Concept: SizeOfConductorAndMaterial Includes 768.2 ACSS as well.
<b>(j)</b> Concept: SizeOfConductorAndMaterial Includes KCMIL AL as well.
<b>(k)</b> Concept: RentExpensesOfTransmissionLine

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 prescribes 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:  
 Public Service Electric & Gas  
 Percentage  
 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).

**(l) Concept: LengthForStandAloneTransmissionLines**

Totals for FERC Page 422-423 Columns F "On structure of Line Designated (F)", Column G "On structures of another Line (G)", and Column H "Number of Circuits (H)" displayed in Row 36 have double counted the values for row 2 230 KV line and row 3 138 KV line as the detail for these lines is broken out below the summary page. Corrected balances should exclude the totals presented on the summary for 230 KV and 138 KV and adjusted balances should be as follows (F) 1764, (G) 187, Column (H) 204.

**(m) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures**

Totals for FERC Page 422-423 Columns F "On structure of Line Designated (F)", Column G "On structures of another Line (G)", and Column H "Number of Circuits (H)" displayed in Row 36 have double counted the values for row 2 230 KV line and row 3 138 KV line as the detail for these lines is broken out below the summary page. Corrected balances should exclude the totals presented on the summary for 230 KV and 138 KV and adjusted balances should be as follows (F) 1764, (G) 187, Column (H) 204.

**(n) Concept: NumberOfTransmissionCircuits**

Totals for FERC Page 422-423 Columns F "On structure of Line Designated (F)", Column G "On structures of another Line (G)", and Column H "Number of Circuits (H)" displayed in Row 36 have double counted the values for row 2 230 KV line and row 3 138 KV line as the detail for these lines is broken out below the summary page. Corrected balances should exclude the totals presented on the summary for 230 KV and 138 KV and adjusted balances should be as follows (F) 1764, (G) 187, Column (H) 204.

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**TRANSMISSION LINES ADDED DURING YEAR**

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION			SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From (a)	To (b)	Line Length in Miles (c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1	RICHFIELD SOLAR	TODD	0.17	0	0			954 ACSR			69						
44	TOTAL		0.17	0	0	0	0										

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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**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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVA)			Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
1	Andora - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0

2	Appleton - Cecil, MD	Distribution	Unattended	35	4	0	7	2	0	0	0	0
3	Basin Road - New Castle, DE 1	Transmission	Unattended	138	69	0	84	1	0	0	0	0
4	Basin Road - New Castle, DE 2	Distribution	Unattended	69	12	0	20	1	0	0	0	0
5	Basin Road - New Castle, DE 3	Distribution	Unattended	138	12	0	22	1	0	69kV Capacitor Bank	1	24
6	Beaglin - Salisbury, MD	Distribution	Unattended	69	25	0	112	2	0	0	0	0
7	Bear - New Castle, DE 1	Distribution	Unattended	138	12	0	112	2	0	0	0	0
8	Bear - New Castle, DE 2	Distribution	Unattended	138	35	0	84	1	0	0	0	0
9	Bethany - Bethany, DE 1	Distribution	Unattended	138	12	0	40	1	0	0	0	0
10	Bethany - Bethany, DE 2	Transmission	Unattended	138	69	0	224	1	0	138kV Capacitor Bank	1	29
11	Bethany - Bethany, DE 3	Distribution	Unattended	69	12	0	22	1	0	69kV Capacitor Bank	2	34
12	Blue Ball Road - Elkton, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
13	Bohemia - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
14	Bozman - Bozman, MD	Distribution	Unattended	69	25	0	28	1	0	0	0	0
15	Brandywine - Wilmington, DE	Distribution	Unattended	138	12	0	168	2	0	12kV Capacitor Bank	2	14
16	Bridgeville - Bridgeville, DE	Distribution	Unattended	69	12	0	37	2	0	69kV Capacitor Bank	2	30
17	Brookside - Pencader, DE	Distribution	Unattended	35	12	0	45	2	0	0	0	0
18	Calvert - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
19	Cambridge - Cambridge, MD	Distribution	Unattended	69	12	0	68	2	0	69kV Capacitor Bank	1	12
20	Carrcroft - Brandywine, DE 1	Transmission	Unattended	138	69	0	112	1	0	0	0	0
21	Carrcroft - Brandywine, DE 2	Distribution	Unattended	138	35	0	84	1	0	34kV Capacitor Bank	2	29
22	Cathers - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
23	Cayots - Cecil, MD	Distribution	Unattended	35	4	0	5	2	0	0	0	0
24	Cecil - Cecil, MD 1	Distribution	Unattended	138	35	0	112	1	0	0	0	0
25	Cecil - Cecil, MD 2	Distribution	Unattended	230	35	0	90	1	0	0	0	0
26	Cecil - Cecil, MD 3	Transmission	Unattended	230	138	0	336	1	0	0	0	0
27	Cecil - Cecil, MD 4	Distribution	Unattended	35	4	0	8	2	0	0	0	0
28	Cedar Creek - New Castle, DE 1	Transmission	Unattended	230	138	0	336	1	0	230kV Reactor	1	40
29	Cedar Creek - New Castle, DE 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
30	Cedar Neck - Cedar Neck, DE	Distribution	Unattended	69	12	0	75	2	0	69kV Capacitor Bank	2	24
31	Centreville - Centreville, MD	Distribution	Unattended	69	12	0	33	2	0	0	0	0
32	Chapel St - Newark, DE	Distribution	Unattended	138	35	0	84	1	0	138kV Capacitor Bank	2	29
33	Charles - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
34	Chesapeake City - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
35	Chestertown - Chestertown, MD	Distribution	Unattended	69	25	0	112	2	0	69kV Capacitor Bank	1	8
36	Chestnut Run - Christiana, DE	Distribution	Unattended	35	12	0	42	2	0	12kV Capacitor Bank	2	6
										138kV		

37	Cheswold - Cheswold, DE 1	Distribution	Unattended	138	25	0	28	1	0	Capacitor Bank	1	19
38	Cheswold - Cheswold, DE 2	Transmission	Unattended	138	69	0	225	1	0	0	0	0
39	Christiana - Wilmington, DE	Distribution	Unattended	138	12	0	168	3	0	12kV Capacitor Bank	6	36
40	Church - Millington, MD 1	Transmission	Unattended	138	69	0	337	2	0	0	0	0
41	Church - Millington, MD 2	Distribution	Unattended	69	25	0	38	2	0	0	0	0
42	Churchmans - New Castle, DE	Distribution	Unattended	138	12	0	106	2	0	0	0	0
43	Claymont - Brandywine, DE	Transmission	Unattended	230	69	0	336	2	0	0	0	0
44	Clayton - Clayton, DE 1	Distribution	Unattended	25	4	0	4	1	0	0	0	0
45	Clayton - Clayton, DE 2	Distribution	Unattended	138	25	0	56	2	0	0	0	0
46	Colora - Cecil, MD	Distribution	Unattended	230	35	0	220	2	0	0	0	0
47	Cool Spring - Milton, DE	Transmission	Unattended	230	69	0	336	1	0	0	0	0
48	Cowlane - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
49	Crest, Cecil Co., MD	Distribution	Unattended	230	35	0	224	2	0	0	0	0
50	Crisfield - Crisfield, MD 1	Distribution	Unattended	69	25	0	28	1	0	0	0	0
51	Crisfield - Crisfield, MD 2	Distribution	Unattended	69	12	0	14	1	0	0	0	0
52	Crothers Road, Cecil Co., MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
53	Culver - Ocean City, MD	Distribution	Unattended	69	25	0	22	1	0	0	0	0
54	Darley - Brandwine, DE 1	Distribution	Unattended	69	12	0	71	2	0	0	0	0
55	Darley - Brandwine, DE 2	Distribution	Unattended	69	35	0	50	1	0	0	0	0
56	Darlington - Harford, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
57	Delaware City- Delaware City, DE	Distribution	Unattended	69	14	0	212	2	0	0	0	0
58	Dublin - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
59	Dupont Experimental- Wilmington, DE	Distribution	Unattended	35	12	0	60	3	0	0	0	0
60	E New Market - East New Market, MD	Distribution	Unattended	69	12	0	34	2	0	0	0	0
61	Easton - Easton, MD	Transmission	Unattended	138	69	0	168	1	0	0	0	0
62	Edgemoor - Brandywine, DE 1	Distribution	Unattended	138	12	0	62	1	0	0	0	0
63	Edgemoor - Brandywine, DE 2	Transmission	Unattended	138	69	0	212	2	0	0	0	0
64	Edgemoor - Brandywine, DE 3	Transmission	Unattended	230	138	0	336	1	0	0	0	0
65	Edgemoor - Brandywine, DE 4	Distribution	Unattended	69	12	0	206	3	0	0	0	0
66	Elkneck - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
67	Elkton - Cecil, MD	Distribution	Unattended	35	4	0	19	4	0	0	0	0
68	Faulk Road - Brandywine, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
69	Felton - Felton, DE	Distribution	Unattended	138	25	0	28	1	0	0	0	0
70	Five Points - Five Points, DE	Distribution	Unattended	69	12	0	45	2	0	0	0	0
71	Foundry - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
72	Frankford - Frankford, DE	Distribution	Unattended	138	25	0	25	1	0	0	0	0
73	Fruitland - Fruitland, MD	Distribution	Unattended	69	25	0	103	2	0	0	0	0
74	Gallion - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
75	Gilpin - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
76	Glasgow - New Castle, DE 1	Distribution	Unattended	138	12	0	28	1	0	0	0	0
77	Glasgow - New Castle, DE 2	Distribution	Unattended	138	35	0	84	1	0	0	0	0
78	Glen - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
79	Grace Street - St. Michaels, MD	Distribution	Unattended	69	12	0	32	2	0	0	0	0
80	Grasonville - Grasonville, MD	Distribution	Unattended	69	25	0	56	2	0	0	0	0
81	Greenbank - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0

82	Hances - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
83	Harbeson - Harbeson, DE	Distribution	Unattended	69	25	0	38	2	0	0	0	0
84	Hares Corner - New Castle, DE	Distribution	Unattended	138	12	0	93	2	0	0	0	0
85	Harford - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
86	Harmony - White Clay, DE 1	Transmission	Unattended	230	138	0	896	2	0	0	0	0
87	Harmony - White Clay, DE 2	Distribution	Unattended	138	35	0	134	2	0	0	0	0
88	Harmony - White Clay, DE 3	Distribution	Unattended	138	12	0	106	2	0	0	0	0
89	Harrington - Harrington, DE	Distribution	Unattended	69	25	0	56	2	0	0	0	0
90	Harris - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
91	Hebron - Hebron, MD	Distribution	Unattended	69	25	0	56	2	0	0	0	0
92	Hillsboro - Hillsboro, MD	Distribution	Unattended	138	25	0	56	2	0	0	0	0
93	Hockessin - Mill Creek, DE	Distribution	Unattended	138	12	0	112	2	0	0	0	0
94	Indian River - Millsboro, DE 1	Transmission	Unattended	230	138	0	1344	3	0	0	0	0
95	Indian River - Millsboro, DE 2	Distribution	Unattended	230	15	0	150	1	0	0	0	0
96	Indian River - Millsboro, DE 3	Transmission	Unattended	138	69	0	225	1	0	0	0	0
97	Irishtown - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
98	Jacktown - Cambridge, MD	Distribution	Unattended	69	12	0	11	1	0	0	0	0
99	Keeney EHV - Pencader Hd, DE 1	Transmission	Unattended	500	230	0	2000	2	0	0	0	0
100	Keeney EHV - Pencader Hd, DE 2	Transmission	Unattended	230	138	0	448	1	0	0	0	0
101	Keeney EHV - Pencader Hd, DE 3	Distribution	Unattended	230	35	0	84	1	0	0	0	0
102	Keeney 138kV - Pencader Hd, DE	Distribution	Unattended	138	12	0	37	1	0	0	0	0
103	Kenney - Snow Hill, MD 1	Distribution	Unattended	69	25	0	13	1	0	0	0	0
104	Kenney - Snow Hill, MD2	Distribution	Unattended	69	12	0	13	1	0	0	0	0
105	Kent - Dover, DE	Distribution	Unattended	69	25	0	47	2	0	0	0	0
106	Kiamensi - Christiana Rd, DE 1	Transmission	Unattended	138	69	0	112	1	0	0	0	0
107	Kiamensi - Christiana Rd, DE 2	Distribution	Unattended	138	35	0	106	2	0	0	0	0
108	Kilby - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
109	Kings Creek - Princess Anne, MD 1	Transmission	Unattended	138	69	0	224	2	0	0	0	0
110	Kings Creek - Princess Anne, MD 2	Distribution	Unattended	138	25	0	56	2	0	0	0	0
111	Laurel - Laurel, DE	Distribution	Unattended	69	12	0	60	2	0	69kV Capacitor Bank	1	20
112	Leslie - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
113	Liberty Grove - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
114	Little Falls - Little Falls, DE	Distribution	Unattended	35	12	0	20	1	0	0	0	0
115	Loretto - Princess Anne, MD	Transmission	Unattended	138	69	0	106	2	0	0	0	0
116	Lums Pond - New Castle, DE	Distribution	Unattended	138	25	0	93	2	0	0	0	0
117	Lynch - Lynch, MD	Distribution	Unattended	69	25	0	28	1	0	0	0	0
118	Macton - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
119	Maridel - Ocean City, MD	Distribution	Unattended	69	12	0	45	2	0	0	0	0
120	Massey - Galena, MD	Distribution	Unattended	69	25	0	28	1	0	69kV Capacitor Bank	1	8
121	Mechanics - Cecil, MD	Distribution	Unattended	35	4	0	3	1	0	0	0	0
122	Mermaid - New Castle, DE 1	Distribution	Unattended	35	12	0	20	1	0	0	0	0
123	Mermaid - New Castle, DE 2	Distribution	Unattended	138	12	0	56	1	0	0	0	0
124	Middle - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
125	Midway - Rehoboth, DE	Distribution	Unattended	69	12	0	60	2	0	0	0	0
126	Milford - Milford, DE 1	Distribution	Unattended	138	25	0	56	1	0	0	0	0



172	Silverside Rd Sub-Brandywine Hd, DE 2	Distribution	Unattended	69	35	0	56	1	0	0	0	0
173	S Harrington Sub-Harrington, DE	Transmission	Unattended	138	69	0	112	1	0	0	0	0
174	Steele-Denton, MD 1	Transmission	Unattended	230	138	0	856	3	0	0	0	0
175	Steele-Denton, MD 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
176	Stevensville, MD	Distribution	Unattended	69	25	0	98	2	0	0	0	0
177	Stockton-Stockton, MD	Distribution	Unattended	69	4	0	5	1	0	0	0	0
178	Sunset Lake Sub-Pencader Hd, DE	Distribution	Unattended	138	12	0	67	2	0	0	0	0
179	Sussex Sub-Georgetown, DE	Distribution	Unattended	69	12	0	48	2	0	0	0	0
180	Talleyville Sub-Brandywine Hd, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
181	Talleyville, DE	Distribution	Unattended	138	12	0	56	1	0	0	0	0
182	Theodore-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
183	Todd-Hurlock, MD 1	Distribution	Unattended	69	25	0	56	2	0	0	0	0
184	Todd-Hurlock, MD 2	Distribution	Unattended	69	12	0	11	1	0	0	0	0
185	Townsend Sub-New Castle Hd, DE	Distribution	Unattended	138	25	0	56	1	0	0	0	0
186	Trappe-Trappe, MD	Distribution	Unattended	69	12	0	50	2	0	0	0	0
187	Triumph-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
188	Vienna-Vienna, MD 1	Transmission	Unattended	138	69	0	224	2	0	0	0	0
189	Vienna-Vienna, MD-Local	Distribution	Unattended	69	12	0	3	1	0	0	0	0
190	Vienna-Vienna, MD 2	Transmission	Unattended	230	138	0	448	1	0	0	0	0
191	Walnut-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
192	Wattsville-Wattsville, VA	Transmission	Unattended	138	69	0	225	1	0	0	0	0
193	West Sub-Christiana Hd, DE 1	Distribution	Unattended	69	35	0	112	2	0	0	0	0
194	West Sub-Christiana Hd, DE 2	Distribution	Unattended	69	12	0	112	2	0	0	0	0
195	West Cambridge, MD	Distribution	Unattended	69	12	0	22	1	0	0	0	0
196	West Wilmington-Wilm, DE	Distribution	Unattended	138	12	0	168	2	0	0	0	0
197	Whiteford-Harford, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
198	Woodlawn-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
199	Worcester-Berlin, MD 1	Distribution	Unattended	69	25	0	66	2	0	0	0	0
200	Worcester-Berlin, MD 2	Transmission	Unattended	138	69	0	224	1	0	0	0	0
201	Wye Mills, Wye Mills, MD 1	Transmission	Unattended	138	69	0	450	2	0	0	0	0
202	Wye Mills, Wye Mills, MD 2	Distribution	Unattended	69	25	0	56	2	0	0	0	0
203	Wyoming, Wyoming, DE	Distribution	Unattended	25	12	0	3	1	0	0	0	0
204	Spare Transformer 1	Distribution	Unattended	138	25	0	28	0	1	0	0	0
205	Spare Transformer 2	Transmission	Unattended	230	138	0	336	0	1	0	0	0
206	Spare Transformer 3	Distribution	Unattended	230	16	0	150	0	1	0	0	0
207	Spare Transformer 4	Distribution	Unattended	69	25	0	56	0	1	0	0	0
208	Spare Transformer 5	Distribution	Unattended	138	16	0	150	0	1	0	0	0
209	Spare Transformer 6	Distribution	Unattended	69	12	0	38	0	1	0	0	0
210	Spare Transformer 7	Transmission	Unattended	230	69	0	336	0	1	0	0	0
211	Spare Transformer 8	Transmission	Unattended	138	69	0	225	0	1	0	0	0
212	Spare Transformer 9	Distribution	Unattended	138	25	0	38	0	1	0	0	0
213	Spare Transformer 10	Distribution	Unattended	138	12	0	38	0	1	0	0	0
214	Spare Transformer 11	Distribution	Unattended	69	35	0	56	0	1	0	0	0
215	Spare Transformer 12	Distribution	Unattended	138	25	0	56	0	1	0	0	0
216	Spare Transformer 13	Distribution	Unattended	34	4	0	4	0	1	0	0	0
217	Spare Transformer 14	Distribution	Unattended	69	12	0	56	0	1	0	0	0
218	Spare Transformer 15	Distribution	Unattended	138	12	0	56	0	1	0	0	0

219	Spare Transformer 16	Distribution	Unattended	34	12	0	20	0	1	0	0	0
220	Spare Transformer 17	Distribution	Unattended	138	36	0	140	0	2	0	0	0
221	Spare Transformer 18	Transmission	Unattended	500	230	0	576	0	2	0	0	0
222	Spare Transformer 19	Transmission	Unattended	230	138	0	784	0	2	0	0	0
223	Spare Transformer 20	Distribution	Unattended	230	35	0	112	0	1	0	0	0
224	Spare Transformer 21	Transmission	Unattended	138	69	0	112	0	1	0	0	0
225	Spare Transformer 22	Distribution	Unattended	35	4	0	4	0	1	0	0	0
226	Spare Transformer 23	Distribution	Unattended	138	12	0	84	0	1	0	0	0
227	Spare Transformer 24	Distribution	Unattended	138	12	0	56	0	1	0	0	0
228	Spare Transformer 25	Distribution	Unattended	35	4	0	4	0	1	0	0	0
229	Spare Transformer 26	Distribution	Unattended	138	36	0	84	0	1	0	0	0
230	Spare Transformer 27	Distribution	Unattended	69	12	0	38	0	1	0	0	0
231	Spare Transformer 28	Distribution	Unattended	34	12	0	22	0	1	0	0	0
232	Spare Transformer 29	Distribution	Unattended	138	12	0	38	0	1	0	0	0
233	Spare transformer 30	Distribution	Unattended	69	25	0	56	0	1	0	0	0
234	Spare Transformer 31	Distribution	Unattended	69	12	0	20	0	1	0	0	0
235	Spare Transformer 32	Distribution	Unattended	69	25	0	28	0	1	0	0	0
236	Spare Transformer 34	Distribution	Unattended	69	25	0	56	0	1	0	0	0
237	Spare Transformer 35	Distribution	Unattended	69	8	0	4	0	1	0	0	0
238	Mobile Transformer 1	Distribution	Unattended	138	25	0	25	0	1	0	0	0
239	Mobile Transformer 2	Distribution	Unattended	69	25	0	12	0	1	0	0	0
240	Mobile Transformer 3	Distribution	Unattended	34	12	0	20	0	1	0	0	0
241	Mobile Transformer 4	Distribution	Unattended	138	12	0	12	0	1	0	0	0
242	Mobile Transformer 5	Distribution	Unattended	69	26	0	40	0	1	0	0	0
243	Mobile Transformer 6	Distribution	Unattended	138	25	0	28	0	1	0	0	0
244	Mobile Transformer 7	Distribution	Unattended	69	25	0	30	0	1	0	0	0
245	Mobile Transformer 8	Distribution	Unattended	69	12	0	27	0	1	0	0	0
246	Mobile Transformer 9	Distribution	Unattended	138	25	0	21	0	1	0	0	0
247	Mobile Transformer 10	Distribution	Unattended	138	25	0	30	0	1	0	0	0
248	Mobile Transformer 11	Distribution	Unattended	138	25	0	30	0	1	0	0	0
249	Mobile Transformer 12	Distribution	Unattended	69	12	0	20		1	0		
250	TOTAL Transmission Substations			8,630	4,416		17502	55	8	—	2	69
251	TOTAL Distribution Substations			17,218	3,183		9918	258	41	—	28	305
252	TOTAL Generation Substations											
253	TOTAL			25,848	7,599		27420	313	49	—	30	374

Name of Respondent: Delmarva Power & Light Company		This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
<b>TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES</b>				
<p>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.</p>				
Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			

2	PHI Service Company (PHISCO)			
3	Centralized Support Services	PHISCO	Various	129,221,833
4	Exelon Business Services Company (EBSC)			
5	Centralized Support Services	EBSC	Various	115,867,851
6	Atlantic City Electric Co (ACE)			
7	Materials	ACE	Various	958,927
8	Facility Services	ACE	184	7,829
9	Mutual Assistance	ACE	Various	20,246
10	Potomac Electric Power Company (Pepco)			
11	Materials	Pepco	Various	446,471
12	Mutual Assistance	Pepco	Various	349,767
13	Atlantic Southern Properties (ASP)			
14	Facility Services	ASP	184	1,118
15	PECO Energy Company (PECO)			
16	Extra-High Voltage (EHV) Transmission Agreement charges	PECO	571	36,492
17	Information Technology Services	PECO	Various	6,585
18	Baltimore Gas & Electric Co. (BGE)			
19	Regulatory Services	BGE	928	(8,515)
20	Information Technology Services	BGE	Various	14,126
21	Drone Training Services	BGE	588	1,061
22	Materials	BGE	154	20,129
23	Other Services	BGE	921	455
24	Commonwealth Edison Company (ComEd)			
25	Information Technology Services	ComEd	Various	11,441
26	Transmission System Operations Services	ComEd	560	52,652
27	Audit Services	ComEd	921	3,058
28	Legal Services	ComEd	921	16,325
19				
20	<b>Non-power Goods or Services Provided for Affiliated</b>			
21	Atlantic City Electric Co (ACE)			
22	Materials	ACE	154/163/232	1,487,425
23	Extra-High Voltage (EHV) Transmission Agreement charges	ACE	456.1	39,144
24	Mutual Assistance	ACE	456	1,277,661
25	Facility Services	ACE	Various	18,232
26	Baltimore Gas & Electric Co. (BGE)			
27	Extra-High Voltage (EHV) Transmission Agreement charges	BGE	456.1	117,432
28	Materials	BGE	154	1,777
29	Potomac Electric Power Company (PEPCO)			
30	Mutual Assistance	PEPCO	456	157,946
31	Materials	PEPCO	154/163/232	1,413,476
32	Extra-High Voltage (EHV) Transmission Agreement charges	PEPCO	456.1	117,432
33	Facility Services	PEPCO	Various	22,633

34	PECO Energy Company (PECO)			
35	Extra-High Voltage (EHV) Transmission Agreement charges	PECO	456.1	143,526
36	Materials	PECO	154	3,032
37	Exelon Business Services Company (EBSC)			
38	Facility Services	EBSC	Various	479,332
39	Vehicle Services	EBSC	456	43,044
40	PHI Service Company (PHISCO)			
41	Facility Services	PHISCO	Various	3,513,573
42	Vehicle Services	PHISCO	456	1,087,285
43	Materials	PHISCO	154/163/232	24,272
42				

FERC FORM NO. 1 ((NEW))

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

**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, distribution planning, engineering services for distribution, substation and transmission, system protection, project and construction management, electric maintenance, administrative support, process improvement, and performance analysis.

(b) Concept: DescriptionOfNonPowerGoodOrService

**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, BSO Operations, real estate, and other.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

PHISCO Centralized Support Services to DPL:

FERC Account	Amount	FERC Account	Amount	FERC Account	Amount
107	\$ 24,526,841	582	3,237	874	21,442
108	3,028,748	583	5,498	875	52
163	647,412	584	13,559	878	668,248
182.3	371,055	586	1,021,121	879	239
184	1,775,363	587	425,056	880	12,347
254	35,906	588	3,094,072	881	50
416	27,696	589	462	885	(14)
419	(486,087)	591	6,188	887	9,160
426.1	344,471	592	87,620	892	6,007
426.3	16,205	593	1,330,754	893	359,576
426.4	232,700	594	15,834	894	385
426.5	1,480,591	595	2,505	902	164,698
430	11,433	596	6,584	903	40,717,775
431	(29,718)	597	723,436	908	2,397,789
557	721,620	598	26,460	909	8,786
560	941,673	813	224,994	910	92,855
561.2	8,480	850	75	923	40,935,784
563	1,236	851	400	924	21,445
566	943,725	856	1,248	925	5,694
569	12,166	857	447	928	882,840
570	182,932	859	12	930.1	341,113
571	368,855	860	277	930.2	223,929
573	5,612	863	2,939	935	1,668
580	114,797	870	1,560		
581	71,890	871	25	Total	\$ 129,221,833

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

EBSC Centralized Support Services to DPL:

FERC Account	Amount	FERC Account	Amount	FERC Account	Amount
107	\$ 40,424,611	589	1,096	874	191,450
108	912,683	591	9,210	875	14,187
163	1,057,848	592	119,576	878	92,024
184	743,744	593	816,810	879	4,330
416	12,287	594	87,323	880	1,503,509
417.1	839	595	14,693	881	90
426.1	222,411	596	23,227	887	40,987

426.3	156,191	597	23,624	889	212
426.4	60,313	598	19,653	892	33,738
426.5	2,858,762	807	8,040	893	19,451
557	2,149	813	29,500	894	527
560	6,960,736	840	164	902	82,259
561.2	18,766	841	65,742	903	12,013,026
563	9	843.4	799	904	96
566	544,019	843.5	422	908	831,378
569	4,220	843.6	499	910	77,833
570	295,350	843.7	77	921	231,973
571	3,604	843.9	1,752	923	41,034,160
573	15,024	850	1,556	924	749,922
580	6,760	851	65,064	925	25,561
581	161,000	856	11,124	928	8,704
582	4,995	857	2,237	930.1	36,952
583	33,169	859	710	930.2	47,077
584	37,675	860	1,049	935	9,415
586	335,810	863	27,747		
587	2,642	870	5,309	Total	\$ 115,867,851
588	2,585,224	871	21,146		

(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

ACE Materials provided to DPL:

FERC Account	Amount
107	\$ 286,337
108	22,504
154	646,331
592	3,750
593	5
Total	\$ 958,927

(f) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

ACE Mutual Assistance provided to DPL:

FERC Account	Amount
107	\$ 916
108	102
593	19,228
Total	\$ 20,246

(g) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Pepco Materials provided to DPL:

FERC Account	Amount
107	\$ 53,545
108	10,888
154	380,867
570	244
593	188
594	23
596	343
598	373
Total	\$ 446,471

(h) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Pepco Mutual Assistance provided to DPL:

FERC Account	Amount
107	\$ 75,765
108	8,418
593	265,584
Total	\$ 349,767

(i) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

PECO Information Technology Services provided to DPL:

FERC Account	Amount
107	\$ 6,155
588	16
921	414
Total	\$ 6,585

(j) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

BGE Information Technology Services provided to DPL:

FERC Account	Amount
107	\$ 3,889
588	10
921	10,227
Total	\$ 14,126

(k) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

ComEd Information Technology Services provided to DPL:

FERC Account	Amount
107	\$ 10,742
908	259
921	440
Total	\$ 11,441

(l) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to ACE:

<b>FERC Account</b>		<b>Amount</b>
456	\$	15,612
495		2,620
Total	\$	18,232

(m) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to Pepco:

<b>FERC Account</b>		<b>Amount</b>
456	\$	19,381
495		3,252
Total	\$	22,633

(n) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to EBSC:

<b>FERC Account</b>		<b>Amount</b>
456	\$	410,452
495		68,880
Total	\$	479,332

(o) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to PHISCO:

<b>FERC Account</b>		<b>Amount</b>
456	\$	3,008,673
495		504,900
Total	\$	3,513,573

FERC FORM NO. 1 ((NEW))

Name of Respondent DPL - Maryland	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of 2023/Q4
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**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	370,564,532	336,452,808
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	146,071,611	143,041,785
5	Large (or Ind.) (See Instr. 4)	11,565,098	11,416,443
6	(444) Public Street and Highway Lighting	4,363,910	4,271,876
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	532,565,151	495,182,912
11	(447) Sales for Resale	1,740,227	1,054,205
12	TOTAL Sales of Electricity	534,305,378	496,237,117
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. For Refunds	534,305,378	496,237,117
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,624,280	939,726
17	(451) Miscellaneous Service Revenues	260,193	95,499
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,872,292	1,580,488
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	5,019,793	554,488
22	(456.1) Revenues from Transmission of Electricity of Others	702,012	693,621
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	9,478,570	3,863,822
27	TOTAL Electric Operating Revenues	543,783,948	500,100,939

Name of Respondent DPL - Maryland	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of 2023/Q4
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**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)	MEGAWATT HOURS SOLD		AVG. NO. CUSTOMERS PER MONTH	
		Year to Date Quarterly/ Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)
1	Sales of Electricity				
2	(440) Residential Sales	2,066,291	2,203,909	184,814	183,381
3	(442) Commercial and Industrial Sales				
4	Small (or Comm.) (See Instr. 4)	1,628,606	1,658,376	28,102	27,876
5	Large (or Ind.) (See Instr. 4)	323,608	349,101	142	152
6	(444) Public Street and Highway Lighting	10,422	10,891	257	258
7	(445) Other Sales to Public Authorities				
8	(446) Sales to Railroads and Railways				
9	(448) Interdepartmental Sales				
10	TOTAL Sales to Ultimate Consumers	4,028,927	4,222,277	213,315	211,667
11	(447) Sales for Resale	127,987	20,992		
12	TOTAL Sales of Electricity	4,156,914	4,243,269	213,315	211,667
13	(Less) (449.1) Provision for Rate Refunds				
14	TOTAL Revenues Net of Prov. For Refunds	4,156,914	4,243,269	213,315	211,667

Line 12, column (b) includes (\$312,040) of unbilled revenues in 2023

Line 12, column (d) includes (33,384) MWH relating to unbilled revenues in 2023

**FOOTNOTE DATA**

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

Items greater than \$250,000:

\$ 1,402,286 MD Bill Stabilization Adjustment  
1,909,419 MD Calendar Revenue Normalization  
(481,775) MD Interconnection Fees  
545,072 Price Responsive Demand Credit  
931,846 MD Intracompany Power Sales  
364,672 Bonus Performance

Name of Respondent DPL - Maryland	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of 2023/Q4
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**Schedule Page: 300 Line No.: 21 Column: c**

Items greater than \$250,000:

- \$ 532,779 RPM Auction
- (466,679) MD Bill Stabilization Adjustment
- (2,445,539) MD Calendar Revenue Normalization
- 451,319 RPM Seasonal Capacity Performance Auction
- 856,050 MD Intracompany Power Sales
- 1,343,906 Price Responsive Demand Credit

**DELMARVA POWER & LIGHT COMPANY**  
**MARYLAND PROPERTY TAXES PAID**  
**12/31/2023**

Location	Rounded 2023 Taxes Paid
Caroline County	1,137,743
Cecil County	4,510,075
City of Cambridge	231,380
City of Crisfield	57,753
City of Fruitland	307,755
City of Salisbury	2,049,979
Delmar	32,495
Dorchester County	3,403,236
Eldorado	-
Galena	3,071
Harford County	552,432
Hebron	11,004
Hillsboro	-
Hurlock	-
Kent County	1,153,644
Mardela Springs	7,463
Pocomoke City	157,419
Preston	4,533
Queen Anne's County	2,021,538
Ridgely	17,691
Secretary	3,112
Sharptown	10,485
Snow Hill	50,400
Somerset County	980,991
St. Michaels	41,652
Sudlersville	-
Talbot County	891,199
Town of Betterton	3,650
Town of Brookview	-
Town of Cecilton	-
Town of Centreville	1,031,880
Town of Charlestown	14,332
Town of Chesapeake City	11,615
Town of Chestertown	47,158
Town of Church Creek	361
Town of Church Hill	34,354
Town of Denton	59,885
Town of East New Market	30,853
Town of Elkton	184,834
Town of Federalsburg	34,694
Town of Goldsboro	1,275
Town of Greensboro	13,575
Town of Henderson	760
Town of Hurlock	27,608
Town of Marydel	1,426
Town of Millington	2,367
Town of North East	61,037
Town of Ocean City	694,249
Town of Perryville	20,862
Town of Pittsville	11,491
Town of Port Deposit	17,153
Town of Prince Anne	-
Town of Queen Anne	6,103
Town of Queenstown	46,365
Town of Rising Sun	11,476
Town of Templeville	1,183
Town of Trappe	8,658
Town of Vienna	6,506
Town of Willards	14,136
Wicomico County	3,131,799
Worcester County	2,576,254
MD Other Property	300
<b>Total</b>	<b>25,745,249</b>

*Filing fee to State of Maryland Department of Assessments*

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, 2024  
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
001-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street Chicago, Illinois 60603-2300 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) 2301 Market Street P.O. Box 8699 Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
001-01910	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 20068-0001 (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 20068-0001 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	21-0398280

**Securities registered pursuant to Section 12(b) of the Act:**

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
<b>EXELON CORPORATION:</b>		
Common stock, without par value	EXC	The Nasdaq Stock Market LLC
<b>PECO ENERGY COMPANY:</b>		
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, \$25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	N/A	N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Exelon Corporation	Large Accelerated Filer <input checked="" type="checkbox"/>	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
Commonwealth Edison Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company
PECO Energy Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company
Baltimore Gas and Electric Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company
Pepco Holdings LLC	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company
Potomac Electric Power Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company
Delmarva Power & Light Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company
Atlantic City Electric Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company	Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The number of shares outstanding of each registrant's common stock as of March 31, 2024 was:

Exelon Corporation Common Stock, without par value	1,000,025,124
Commonwealth Edison Company Common Stock, \$12.50 par value	127,021,409
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, \$0.01 par value	100
Delmarva Power & Light Company Common Stock, \$2.25 par value	1,000
Atlantic City Electric Company Common Stock, \$3.00 par value	8,546,017

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## GLOSSARY OF TERMS AND ABBREVIATIONS

### **Exelon Corporation and Related Entities**

<i>Exelon</i>	Exelon Corporation
<i>ComEd</i>	Commonwealth Edison Company
<i>PECO</i>	PECO Energy Company
<i>BGE</i>	Baltimore Gas and Electric Company
<i>Pepco Holdings or PHI</i>	Pepco Holdings LLC
<i>Pepco</i>	Potomac Electric Power Company
<i>DPL</i>	Delmarva Power & Light Company
<i>ACE</i>	Atlantic City Electric Company
<i>Registrants</i>	Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
<i>Utility Registrants</i>	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
<i>BSC</i>	Exelon Business Services Company, LLC
<i>Exelon Corporate</i>	Exelon in its corporate capacity as a holding company
<i>PCI</i>	Potomac Capital Investment Corporation and its subsidiaries
<i>PECO Trust III</i>	PECO Energy Capital Trust III
<i>PECO Trust IV</i>	PECO Energy Capital Trust IV
<i>PHI Corporate</i>	PHI in its corporate capacity as a holding company
<i>PHISCO</i>	PHI Service Company

### **Former Related Entities**

<i>Constellation</i>	Constellation Energy Corporation
<i>Generation</i>	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC, a subsidiary of Exelon prior to separation on February 1, 2022)

## GLOSSARY OF TERMS AND ABBREVIATIONS

### Other Terms and Abbreviations

<i>Note - of the 2023 Form 10-K</i>	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2023 Annual Report on Form 10-K
<i>ABO</i>	Accumulated Benefit Obligation
<i>AFUDC</i>	Allowance for Funds Used During Construction
<i>AMI</i>	Advanced Metering Infrastructure
<i>AOCI</i>	Accumulated Other Comprehensive Income (Loss)
<i>ARO</i>	Asset Retirement Obligation
<i>ATM</i>	At the market
<i>BGS</i>	Basic Generation Service
<i>BSA</i>	Bill Stabilization Adjustment
<i>CEJA</i>	Climate and Equitable Jobs Act; Illinois Public Act 102-0662 signed into law on September 15, 2021
<i>CERCLA</i>	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
<i>CIP</i>	Conservation Incentive Program
<i>CMC</i>	Carbon Mitigation Credit
<i>CODMs</i>	Chief Operating Decision Makers
<i>DC PLUG</i>	District of Columbia Power Line Undergrounding Initiative
<i>DCPSC</i>	Public Service Commission of the District of Columbia
<i>DEPSC</i>	Delaware Public Service Commission
<i>DOEE</i>	District of Columbia Department of Energy & Environment
<i>DPA</i>	Deferred Prosecution Agreement
<i>DSIC</i>	Distribution System Improvement Charge
<i>EIMA</i>	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
<i>EPA</i>	United States Environmental Protection Agency
<i>ERISA</i>	Employee Retirement Income Security Act of 1974, as amended
<i>ETAC</i>	Energy Transition Assistance Charge
<i>FERC</i>	Federal Energy Regulatory Commission
<i>GAAP</i>	Generally Accepted Accounting Principles in the United States
<i>GCR</i>	Gas Cost Rate
<i>GSA</i>	Generation Supply Adjustment
<i>GWhs</i>	Gigawatt hours
<i>ICC</i>	Illinois Commerce Commission
<i>IJA</i>	Infrastructure Investment and Jobs Act
<i>Illinois Settlement Legislation</i>	Legislation enacted in 2007 affecting electric utilities in Illinois
<i>IPA</i>	Illinois Power Agency
<i>IRA</i>	Inflation Reduction Act
<i>IRC</i>	Internal Revenue Code
<i>IRS</i>	Internal Revenue Service
<i>MDPSC</i>	Maryland Public Service Commission
<i>MGP</i>	Manufactured Gas Plant
<i>mmcf</i>	Million Cubic Feet
<i>MRP</i>	Multi-Year Rate Plan
<i>MWh</i>	Megawatt hour
<i>N/A</i>	Not applicable
<i>NAV</i>	Net Asset Value



## GLOSSARY OF TERMS AND ABBREVIATIONS

### **Other Terms and Abbreviations**

<i>NJBPU</i>	New Jersey Board of Public Utilities
<i>NPNS</i>	Normal Purchase Normal Sale scope exception
<i>NPS</i>	National Park Service
<i>NRD</i>	Natural Resources Damages
<i>OCI</i>	Other Comprehensive Income
<i>OPEB</i>	Other Postretirement Employee Benefits
<i>PAPUC</i>	Pennsylvania Public Utility Commission
<i>PGC</i>	Purchased Gas Cost Clause
<i>PJM</i>	PJM Interconnection, LLC
<i>POLR</i>	Provider of Last Resort
<i>PPA</i>	Power Purchase Agreement
<i>PRPs</i>	Potentially Responsible Parties
<i>REC</i>	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
<i>Regulatory Agreement Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
<i>Rider</i>	Reconcilable Surcharge Recovery Mechanism
<i>ROE</i>	Return on equity
<i>ROU</i>	Right-of-use
<i>RTO</i>	Regional Transmission Organization
<i>SEC</i>	United States Securities and Exchange Commission
<i>SOFR</i>	Secured Overnight Financing Rate
<i>SOS</i>	Standard Offer Service
<i>TCJA</i>	Tax Cuts and Jobs Act
<i>ZEC</i>	Zero Emission Credit or Zero Emission Certificate

## **FILING FORMAT**

This combined Form 10-Q is being filed separately by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

## **CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION**

This Report contains certain forward-looking statements within the meaning of federal securities laws that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” “should,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic, and financial performance, are intended to identify such forward-looking statements.

The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) the 2023 Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 18, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, ITEM 1A. Risk Factors, (b) Part I, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1. Financial Statements: Note 11, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Investors are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

## **WHERE TO FIND MORE INFORMATION**

The SEC maintains an Internet site at [www.sec.gov](http://www.sec.gov) that contains reports, proxy and information statements, and other information that the Registrants file electronically with the SEC. These documents are also available to the public from commercial document retrieval services and free of charge at the Registrants’ website at [www.exeloncorp.com](http://www.exeloncorp.com). Information contained on the Registrants’ website shall not be deemed incorporated into, or to be a part of, this Report.

**PART I. FINANCIAL INFORMATION**

**ITEM 1. FINANCIAL STATEMENTS**

**EXELON CORPORATION AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
(Unaudited)

(In millions, except per share data)	Three Months Ended March 31,	
	2024	2023
<b>Operating revenues</b>		
Electric operating revenues	\$ 5,198	\$ 4,462
Natural gas operating revenues	739	822
Revenues from alternative revenue programs	106	279
Total operating revenues	6,043	5,563
<b>Operating expenses</b>		
Purchased power	2,197	1,733
Purchased fuel	213	358
Operating and maintenance	1,271	1,151
Depreciation and amortization	879	860
Taxes other than income taxes	371	355
Total operating expenses	4,931	4,457
<b>Gain on sale of assets and businesses</b>	2	—
<b>Operating income</b>	1,114	1,106
<b>Other income and (deductions)</b>		
Interest expense, net	(462)	(406)
Interest expense to affiliates	(6)	(6)
Other, net	75	109
Total other income and (deductions)	(393)	(303)
<b>Income before income taxes</b>	721	803
<b>Income taxes</b>	63	134
<b>Net income attributable to common shareholders</b>	\$ 658	\$ 669
<b>Comprehensive income, net of income taxes</b>		
Net income	\$ 658	\$ 669
<b>Other comprehensive income (loss), net of income taxes</b>		
Pension and non-pension postretirement benefit plans:		
Actuarial losses reclassified to periodic benefit cost	5	3
Pension and non-pension postretirement benefit plans valuation adjustments	(24)	(10)
Unrealized gains on cash flow hedges	33	6
Other comprehensive income (loss)	14	(1)
<b>Comprehensive income attributable to common shareholders</b>	\$ 672	\$ 668
<b>Average shares of common stock outstanding:</b>		
Basic	1,000	995
Assumed exercise and/or distributions of stock-based awards <sup>(a)</sup>	1	1
Diluted	1,001	996
<b>Earnings per average common share</b>		
Basic	\$ 0.66	\$ 0.67
Diluted	\$ 0.66	\$ 0.67

(a) The dilutive effects of stock-based compensation awards are calculated using the treasury stock method for all periods presented.

See the Combined Notes to Consolidated Financial Statements

**EXELON CORPORATION AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 658	\$ 669
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion	880	860
Gain on sales of assets and businesses	(2)	—
Deferred income taxes and amortization of investment tax credits	46	113
Net fair value changes related to derivatives	1	—
Other non-cash operating activities	39	(138)
Changes in assets and liabilities:		
Accounts receivable	(309)	106
Inventories	12	102
Accounts payable and accrued expenses	(238)	(482)
Collateral received (paid), net	7	(214)
Income taxes	21	23
Regulatory assets and liabilities, net	252	(324)
Pension and non-pension postretirement benefit contributions	(111)	(44)
Other assets and liabilities	(264)	(187)
Net cash flows provided by operating activities	992	484
<b>Cash flows from investing activities</b>		
Capital expenditures	(1,767)	(1,881)
Proceeds from sales of assets and businesses	2	—
Other investing activities	(2)	10
Net cash flows used in investing activities	(1,767)	(1,871)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(317)	(1,130)
Proceeds from short-term borrowings with maturities greater than 90 days	150	—
Repayments on short-term borrowings with maturities greater than 90 days	(150)	(150)
Issuance of long-term debt	2,625	3,925
Retirement of long-term debt	(901)	(857)
Dividends paid on common stock	(381)	(358)
Proceeds from employee stock plans	11	10
Other financing activities	(55)	(60)
Net cash flows provided by financing activities	982	1,380
<b>Increase (decrease) in cash, restricted cash, and cash equivalents</b>	207	(7)
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	1,101	1,090
<b>Cash, restricted cash, and cash equivalents at end of period</b>	\$ 1,308	\$ 1,083
<b>Supplemental cash flow information</b>		
Decrease in capital expenditures not paid	\$ (117)	\$ (201)

See the Combined Notes to Consolidated Financial Statements

**EXELON CORPORATION AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 720	\$ 445
Restricted cash and cash equivalents	489	482
Accounts receivable		
Customer accounts receivable	2,896	2,659
Customer allowance for credit losses	(346)	(317)
Customer accounts receivable, net	2,550	2,342
Other accounts receivable	1,131	1,101
Other allowance for credit losses	(96)	(82)
Other accounts receivable, net	1,035	1,019
Inventories, net		
Fossil fuel	37	94
Materials and supplies	751	707
Regulatory assets	2,035	2,215
Other	595	473
Total current assets	<u>8,212</u>	<u>7,777</u>
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$17,711 and \$17,251 as of March 31, 2024 and December 31, 2023, respectively)</b>	74,604	73,593
<b>Deferred debits and other assets</b>		
Regulatory assets	8,701	8,698
Goodwill	6,630	6,630
Receivable related to Regulatory Agreement Units	3,382	3,232
Investments	263	251
Other	1,419	1,365
Total deferred debits and other assets	<u>20,395</u>	<u>20,176</u>
<b>Total assets</b>	<u>\$ 103,211</u>	<u>\$ 101,546</u>

See the Combined Notes to Consolidated Financial Statements

**EXELON CORPORATION AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
(Unaudited)

(In millions)	March 31, 2024	December 31, 2023
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 2,206	\$ 2,523
Long-term debt due within one year	503	1,403
Accounts payable	2,814	2,846
Accrued expenses	1,076	1,375
Payables to affiliates	5	5
Customer deposits	419	411
Regulatory liabilities	400	389
Mark-to-market derivative liabilities	29	74
Unamortized energy contract liabilities	7	8
Other	516	557
Total current liabilities	7,975	9,591
<b>Long-term debt</b>	42,271	39,692
<b>Long-term debt to financing trusts</b>	390	390
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	12,199	11,956
Regulatory liabilities	9,706	9,576
Pension obligations	1,569	1,571
Non-pension postretirement benefit obligations	523	527
Asset retirement obligations	270	267
Mark-to-market derivative liabilities	80	106
Unamortized energy contract liabilities	25	27
Other	2,142	2,088
Total deferred credits and other liabilities	26,514	26,118
Total liabilities	77,150	75,791
<b>Commitments and contingencies</b>		
<b>Shareholders' equity</b>		
Common stock (No par value, 2,000 shares authorized, 1,000 shares and 999 shares outstanding as of March 31, 2024 and December 31, 2023, respectively)	21,129	21,114
Treasury stock, at cost (2 shares as of March 31, 2024 and December 31, 2023)	(123)	(123)
Retained earnings	5,767	5,490
Accumulated other comprehensive loss, net	(712)	(726)
Total shareholders' equity	26,061	25,755
<b>Total liabilities and shareholders' equity</b>	\$ 103,211	\$ 101,546

See the Combined Notes to Consolidated Financial Statements

**EXELON CORPORATION AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY**  
**(Unaudited)**

	Three Months Ended March 31, 2024					
<u>(In millions, shares in thousands)</u>	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity
<b>Balance at December 31, 2023</b>	1,001,249	\$ 21,114	\$ (123)	\$ 5,490	\$ (726)	\$ 25,755
Net income	—	—	—	658	—	658
Long-term incentive plan activity	333	2	—	—	—	2
Employee stock purchase plan issuances	276	13	—	—	—	13
Common stock dividends (\$0.38/common share)	—	—	—	(381)	—	(381)
Other comprehensive income, net of income taxes	—	—	—	—	14	14
<b>Balance at March 31, 2024</b>	<u>1,001,858</u>	<u>\$ 21,129</u>	<u>\$ (123)</u>	<u>\$ 5,767</u>	<u>\$ (712)</u>	<u>\$ 26,061</u>

	Three Months Ended March 31, 2023					
<u>(In millions, shares in thousands)</u>	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity
<b>Balance at December 31, 2022</b>	995,830	\$ 20,908	\$ (123)	\$ 4,597	\$ (638)	\$ 24,744
Net income	—	—	—	669	—	669
Long-term incentive plan activity	306	1	—	—	—	1
Employee stock purchase plan issuances	266	12	—	—	—	12
Common stock dividends (\$0.36/common share)	—	—	—	(359)	—	(359)
Other comprehensive loss, net of income taxes	—	—	—	—	(1)	(1)
<b>Balance at March 31, 2023</b>	<u>996,402</u>	<u>\$ 20,921</u>	<u>\$ (123)</u>	<u>\$ 4,907</u>	<u>\$ (639)</u>	<u>\$ 25,066</u>

See the Combined Notes to Consolidated Financial Statements

**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
**(Unaudited)**

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Operating revenues</b>		
Electric operating revenues	\$ 2,074	\$ 1,511
Revenues from alternative revenue programs	19	153
Operating revenues from affiliates	2	3
Total operating revenues	<u>2,095</u>	<u>1,667</u>
<b>Operating expenses</b>		
Purchased power	907	488
Operating and maintenance	318	254
Operating and maintenance from affiliates	100	83
Depreciation and amortization	362	338
Taxes other than income taxes	94	93
Total operating expenses	<u>1,781</u>	<u>1,256</u>
<b>Operating income</b>	<u>314</u>	<u>411</u>
<b>Other income and (deductions)</b>		
Interest expense, net	(119)	(114)
Interest expense to affiliates	(3)	(3)
Other, net	20	18
Total other income and (deductions)	<u>(102)</u>	<u>(99)</u>
<b>Income before income taxes</b>	<u>212</u>	<u>312</u>
<b>Income taxes</b>	19	71
<b>Net income</b>	<u>\$ 193</u>	<u>\$ 241</u>
<b>Comprehensive income</b>	<u>\$ 193</u>	<u>\$ 241</u>

See the Combined Notes to Consolidated Financial Statements

**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
**(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>March 31,</b>	
	<b>2024</b>	<b>2023</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 193	\$ 241
Adjustments to reconcile net income to net cash flows provided by (used in) operating activities:		
Depreciation and amortization	362	338
Deferred income taxes and amortization of investment tax credits	(1)	55
Other non-cash operating activities	(6)	(153)
Changes in assets and liabilities:		
Accounts receivable	(133)	96
Receivables from and payables to affiliates, net	—	10
Inventories	(11)	(21)
Accounts payable and accrued expenses	(116)	(306)
Collateral received (paid), net	8	(4)
Income taxes	21	15
Regulatory assets and liabilities, net	315	(338)
Pension and non-pension postretirement benefit contributions	(5)	(23)
Other assets and liabilities	(67)	(22)
Net cash flows provided by (used in) operating activities	560	(112)
<b>Cash flows from investing activities</b>		
Capital expenditures	(594)	(617)
Other investing activities	1	1
Net cash flows used in investing activities	(593)	(616)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	128	(18)
Repayments on short-term borrowings with maturities greater than 90 days	—	(150)
Issuance of long-term debt	—	975
Dividends paid on common stock	(194)	(187)
Contributions from parent	39	186
Other financing activities	1	(11)
Net cash flows (used in) provided by financing activities	(26)	795
<b>(Decrease) increase in cash, restricted cash, and cash equivalents</b>	(59)	67
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	686	511
<b>Cash, restricted cash, and cash equivalents at end of period</b>	\$ 627	\$ 578
<b>Supplemental cash flow information</b>		
Decrease in capital expenditures not paid	\$ (74)	\$ (35)

See the Combined Notes to Consolidated Financial Statements

**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 100	\$ 110
Restricted cash and cash equivalents	428	402
Accounts receivable		
Customer accounts receivable	1,003	860
Customer allowance for credit losses	(82)	(69)
Customer accounts receivable, net	921	791
Other accounts receivable	230	242
Other allowance for credit losses	(19)	(17)
Other accounts receivable, net	211	225
Receivables from affiliates	3	3
Inventories, net	289	279
Regulatory assets	1,137	1,335
Other	141	123
Total current assets	3,230	3,268
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$7,409 and \$7,222 as of March 31, 2024 and December 31, 2023, respectively)</b>	29,371	29,088
<b>Deferred debits and other assets</b>		
Regulatory assets	2,706	2,794
Goodwill	2,625	2,625
Receivable related to Regulatory Agreement Units	3,078	2,954
Investments	6	6
Prepaid pension asset	1,207	1,217
Other	909	875
Total deferred debits and other assets	10,531	10,471
<b>Total assets</b>	<b>\$ 43,132</b>	<b>\$ 42,827</b>

See the Combined Notes to Consolidated Financial Statements

**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
(Unaudited)

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 730	\$ 602
Long-term debt due within one year	250	250
Accounts payable	859	867
Accrued expenses	414	576
Payables to affiliates	72	72
Customer deposits	122	118
Regulatory liabilities	191	191
Mark-to-market derivative liabilities	29	27
Other	214	219
Total current liabilities	2,881	2,922
<b>Long-term debt</b>	<b>11,237</b>	<b>11,236</b>
<b>Long-term debt to financing trust</b>	<b>205</b>	<b>205</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	5,384	5,327
Regulatory liabilities	7,697	7,493
Asset retirement obligations	150	149
Non-pension postretirement benefits obligations	163	161
Mark-to-market derivative liabilities	79	106
Other	935	865
Total deferred credits and other liabilities	14,408	14,101
Total liabilities	28,731	28,464
<b>Commitments and contingencies</b>		
<b>Shareholders' equity</b>		
Common stock	1,588	1,588
Other paid-in capital	10,440	10,401
Retained earnings	2,373	2,374
Total shareholders' equity	14,401	14,363
<b>Total liabilities and shareholders' equity</b>	<b>\$ 43,132</b>	<b>\$ 42,827</b>

See the Combined Notes to Consolidated Financial Statements

**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY**  
**(Unaudited)**

	Three Months Ended March 31, 2024			
<i>(In millions)</i>	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
<b>Balance at December 31, 2023</b>	\$ 1,588	\$ 10,401	\$ 2,374	\$ 14,363
Net income	—	—	193	193
Common stock dividends	—	—	(194)	(194)
Contributions from parent	—	39	—	39
<b>Balance at March 31, 2024</b>	<u>\$ 1,588</u>	<u>\$ 10,440</u>	<u>\$ 2,373</u>	<u>\$ 14,401</u>

	Three Months Ended March 31, 2023			
<i>(In millions)</i>	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
<b>Balance at December 31, 2022</b>	\$ 1,588	\$ 9,746	\$ 2,030	\$ 13,364
Net income	—	—	241	241
Common stock dividends	—	—	(187)	(187)
Contributions from parent	—	186	—	186
<b>Balance at March 31, 2023</b>	<u>\$ 1,588</u>	<u>\$ 9,932</u>	<u>\$ 2,084</u>	<u>\$ 13,604</u>

See the Combined Notes to Consolidated Financial Statements

**PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Operating revenues</b>		
Electric operating revenues	\$ 782	\$ 798
Natural gas operating revenues	272	316
Revenues from alternative revenue programs	(2)	(4)
Operating revenues from affiliates	2	2
Total operating revenues	1,054	1,112
<b>Operating expenses</b>		
Purchased power	306	330
Purchased fuel	97	154
Operating and maintenance	235	219
Operating and maintenance from affiliates	58	51
Depreciation and amortization	104	98
Taxes other than income taxes	51	50
Total operating expenses	851	902
<b>Gain on sales of assets</b>	2	—
<b>Operating income</b>	205	210
<b>Other income and (deductions)</b>		
Interest expense, net	(52)	(45)
Interest expense to affiliates	(3)	(3)
Other, net	9	8
Total other income and (deductions)	(46)	(40)
<b>Income before income taxes</b>	159	170
<b>Income taxes</b>	10	4
<b>Net income</b>	\$ 149	\$ 166
<b>Comprehensive income</b>	\$ 149	\$ 166

See the Combined Notes to Consolidated Financial Statements

**PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 149	\$ 166
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	104	98
Gain on sales of assets	(2)	—
Deferred income taxes and amortization of investment tax credits	(8)	(16)
Other non-cash operating activities	20	32
Changes in assets and liabilities:		
Accounts receivable	(75)	36
Receivables from and payables to affiliates, net	4	8
Inventories	19	60
Accounts payable and accrued expenses	(63)	(176)
Income taxes	19	20
Regulatory assets and liabilities, net	(20)	15
Pension and non-pension postretirement benefit contributions	(2)	—
Other assets and liabilities	(104)	(75)
Net cash flows provided by operating activities	41	168
<b>Cash flows from investing activities</b>		
Capital expenditures	(361)	(335)
Other investing activities	2	—
Net cash flows used in investing activities	(359)	(335)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(165)	(94)
Dividends paid on common stock	(100)	(101)
Contributions from parent	580	330
Net cash flows provided by financing activities	315	135
<b>Decrease in cash, restricted cash, and cash equivalents</b>	(3)	(32)
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	51	68
<b>Cash, restricted cash, and cash equivalents at end of period</b>	\$ 48	\$ 36
<b>Supplemental cash flow information</b>		
Increase (decrease) in capital expenditures not paid	\$ 5	\$ (9)

See the Combined Notes to Consolidated Financial Statements  
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**PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 39	\$ 42
Restricted cash and cash equivalents	9	9
Accounts receivable		
Customer accounts receivable	562	527
Customer allowance for credit losses	(107)	(95)
Customer accounts receivable, net	455	432
Other accounts receivable	160	117
Other allowance for credit losses	(13)	(8)
Other accounts receivable, net	147	109
Receivables from affiliates	—	2
Inventories, net		
Fossil fuel	22	50
Materials and supplies	76	67
Prepaid utility taxes	128	2
Regulatory assets	128	127
Other	78	63
Total current assets	1,082	903
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,149 and \$4,097 as of March 31, 2024 and December 31, 2023, respectively)</b>	13,399	13,128
<b>Deferred debits and other assets</b>		
Regulatory assets	834	793
Receivable related to Regulatory Agreement Units	304	278
Investments	37	35
Prepaid pension asset	432	429
Other	28	29
Total deferred debits and other assets	1,635	1,564
<b>Total assets</b>	<u>\$ 16,116</u>	<u>\$ 15,595</u>

See the Combined Notes to Consolidated Financial Statements

**PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
**(Unaudited)**

(In millions)	March 31, 2024	December 31, 2023
<b>LIABILITIES AND SHAREHOLDER'S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ —	\$ 165
Accounts payable	524	512
Accrued expenses	198	236
Payables to affiliates	41	39
Customer deposits	78	79
Renewable energy credit obligation	54	36
Regulatory liabilities	83	92
Other	31	23
Total current liabilities	1,009	1,182
<b>Long-term debt</b>	5,134	5,134
<b>Long-term debt to financing trusts</b>	184	184
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	2,349	2,321
Regulatory liabilities	340	314
Asset retirement obligations	27	26
Non-pension postretirement benefits obligations	287	286
Other	88	79
Total deferred credits and other liabilities	3,091	3,026
Total liabilities	9,418	9,526
<b>Commitments and contingencies</b>		
<b>Shareholder's equity</b>		
Common stock	4,630	4,050
Retained earnings	2,068	2,019
Total shareholder's equity	6,698	6,069
<b>Total liabilities and shareholder's equity</b>	<b>\$ 16,116</b>	<b>\$ 15,595</b>

See the Combined Notes to Consolidated Financial Statements

**PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY**  
**(Unaudited)**

<u>(In millions)</u>	Three Months Ended March 31, 2024		
	Common Stock	Retained Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2023</b>	\$ 4,050	\$ 2,019	\$ 6,069
Net income	—	149	149
Common stock dividends	—	(100)	(100)
Contributions from parent	580	—	580
<b>Balance at March 31, 2024</b>	<b>\$ 4,630</b>	<b>\$ 2,068</b>	<b>\$ 6,698</b>

<u>(In millions)</u>	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2022</b>	\$ 3,702	\$ 1,861	\$ 5,563
Net income	—	166	166
Common stock dividends	—	(101)	(101)
Contributions from parent	330	—	330
<b>Balance at March 31, 2023</b>	<b>\$ 4,032</b>	<b>\$ 1,926</b>	<b>\$ 5,958</b>

See the Combined Notes to Consolidated Financial Statements

**BALTIMORE GAS AND ELECTRIC COMPANY**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
**(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2024</b>	<b>2023</b>
<b>Operating revenues</b>		
Electric operating revenues	\$ 857	\$ 780
Natural gas operating revenues	395	409
Revenues from alternative revenue programs	43	65
Operating revenues from affiliates	2	3
Total operating revenues	1,297	1,257
<b>Operating expenses</b>		
Purchased power	377	343
Purchased fuel	87	149
Operating and maintenance	205	168
Operating and maintenance from affiliates	59	54
Depreciation and amortization	150	167
Taxes other than income taxes	89	83
Total operating expenses	967	964
<b>Operating income</b>	330	293
<b>Other income and (deductions)</b>		
Interest expense, net	(50)	(44)
Other, net	8	3
Total other income and (deductions)	(42)	(41)
<b>Income before income taxes</b>	288	252
<b>Income taxes</b>	24	52
<b>Net income</b>	\$ 264	\$ 200
<b>Comprehensive income</b>	\$ 264	\$ 200

See the Combined Notes to Consolidated Financial Statements

**BALTIMORE GAS AND ELECTRIC COMPANY**  
**STATEMENTS OF CASH FLOWS**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 264	\$ 200
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	150	167
Deferred income taxes and amortization of investment tax credits	(4)	24
Other non-cash operating activities	(21)	(32)
Changes in assets and liabilities:		
Accounts receivable	(95)	43
Receivables from and payables to affiliates, net	2	(3)
Inventories	14	62
Accounts payable and accrued expenses	21	(96)
Collateral paid, net	—	(22)
Income taxes	29	29
Regulatory assets and liabilities, net	—	(31)
Pension and non-pension postretirement benefit contributions	(25)	(8)
Other assets and liabilities	(18)	(24)
Net cash flows provided by operating activities	317	309
<b>Cash flows from investing activities</b>		
Capital expenditures	(324)	(350)
Other investing activities	8	3
Net cash flows used in investing activities	(316)	(347)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	70	(165)
Dividends paid on common stock	(92)	(80)
Contributions from parent	—	237
Net cash flows used in financing activities	(22)	(8)
<b>Decrease in cash, restricted cash, and cash equivalents</b>	(21)	(46)
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	48	67
<b>Cash, restricted cash, and cash equivalents at end of period</b>	\$ 27	\$ 21
<b>Supplemental cash flow information</b>		
Decrease in capital expenditures not paid	\$ (8)	\$ (70)

See the Combined Notes to Consolidated Financial Statements  
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**BALTIMORE GAS AND ELECTRIC COMPANY**  
**BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 27	\$ 47
Restricted cash and cash equivalents	—	1
Accounts receivable		
Customer accounts receivable	618	527
Customer allowance for credit losses	(52)	(46)
Customer accounts receivable, net	566	481
Other accounts receivable	104	106
Other allowance for credit losses	(7)	(7)
Other accounts receivable, net	97	99
Inventories, net		
Fossil fuel	13	35
Materials and supplies	82	74
Prepaid utility taxes	54	56
Regulatory assets	237	229
Other	18	25
Total current assets	1,094	1,047
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,817 and \$4,744 as of March 31, 2024 and December 31, 2023, respectively)</b>	12,291	12,102
<b>Deferred debits and other assets</b>		
Regulatory assets	742	727
Investments	10	9
Prepaid pension asset	253	248
Other	54	51
Total deferred debits and other assets	1,059	1,035
<b>Total assets</b>	<b>\$ 14,444</b>	<b>\$ 14,184</b>

See the Combined Notes to Consolidated Financial Statements

**BALTIMORE GAS AND ELECTRIC COMPANY**  
**BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>LIABILITIES AND SHAREHOLDER'S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 406	\$ 336
Accounts payable	338	344
Accrued expenses	249	203
Payables to affiliates	37	35
Customer deposits	115	114
Regulatory liabilities	26	27
Other	24	34
Total current liabilities	1,195	1,093
<b>Long-term debt</b>		
	4,602	4,602
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	2,016	1,945
Regulatory liabilities	699	773
Asset retirement obligations	32	32
Non-pension postretirement benefits obligations	153	158
Other	85	91
Total deferred credits and other liabilities	2,985	2,999
Total liabilities	8,782	8,694
<b>Commitments and contingencies</b>		
<b>Shareholder's equity</b>		
Common stock	3,246	3,246
Retained earnings	2,416	2,244
Total shareholder's equity	5,662	5,490
<b>Total liabilities and shareholder's equity</b>	<b>\$ 14,444</b>	<b>\$ 14,184</b>

See the Combined Notes to Consolidated Financial Statements

**BALTIMORE GAS AND ELECTRIC COMPANY**  
**STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY**  
**(Unaudited)**

	<u>Three Months Ended March 31, 2024</u>		
<u>(In millions)</u>	<u>Common Stock</u>	<u>Retained Earnings</u>	<u>Total Shareholder's Equity</u>
<b>Balance at December 31, 2023</b>	\$ 3,246	\$ 2,244	\$ 5,490
Net income	—	264	264
Common stock dividends	—	(92)	(92)
<b>Balance at March 31, 2024</b>	<u>\$ 3,246</u>	<u>\$ 2,416</u>	<u>\$ 5,662</u>

	<u>Three Months Ended March 31, 2023</u>		
<u>(In millions)</u>	<u>Common Stock</u>	<u>Retained Earnings</u>	<u>Total Shareholder's Equity</u>
<b>Balance at December 31, 2022</b>	\$ 2,861	\$ 2,075	\$ 4,936
Net income	—	200	200
Common stock dividends	—	(80)	(80)
Contributions from parent	237	—	237
<b>Balance at March 31, 2023</b>	<u>\$ 3,098</u>	<u>\$ 2,195</u>	<u>\$ 5,293</u>

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**PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Operating revenues</b>		
Electric operating revenues	\$ 1,485	\$ 1,371
Natural gas operating revenues	72	97
Revenues from alternative revenue programs	46	65
Operating revenues from affiliates	3	3
Total operating revenues	<u>1,606</u>	<u>1,536</u>
<b>Operating expenses</b>		
Purchased power	607	572
Purchased fuel	29	55
Operating and maintenance	274	267
Operating and maintenance from affiliates	51	42
Depreciation and amortization	246	241
Taxes other than income taxes	128	120
Total operating expenses	<u>1,335</u>	<u>1,297</u>
<b>Operating income</b>	<u>271</u>	<u>239</u>
<b>Other income and (deductions)</b>		
Interest expense, net	(90)	(76)
Other, net	27	26
Total other income and (deductions)	<u>(63)</u>	<u>(50)</u>
<b>Income before income taxes</b>	208	189
<b>Income taxes</b>	40	34
<b>Net income</b>	<u>\$ 168</u>	<u>\$ 155</u>
<b>Comprehensive income</b>	<u>\$ 168</u>	<u>\$ 155</u>

See the Combined Notes to Consolidated Financial Statements

**PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 168	\$ 155
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	246	241
Deferred income taxes and amortization of investment tax credits	16	13
Other non-cash operating activities	9	(7)
Changes in assets and liabilities:		
Accounts receivable	1	98
Inventories	(11)	4
Accounts payable and accrued expenses	(23)	(88)
Collateral paid, net	—	(189)
Income taxes	24	20
Regulatory assets and liabilities, net	(42)	27
Pension and non-pension postretirement benefit contributions	(72)	(7)
Other assets and liabilities	(27)	(11)
Net cash flows provided by operating activities	289	256
<b>Cash flows from investing activities</b>		
Capital expenditures	(453)	(561)
Other investing activities	—	8
Net cash flows used in investing activities	(453)	(553)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(394)	(414)
Issuance of long-term debt	925	450
Retirement of long-term debt	(400)	—
Changes in Exelon intercompany money pool	8	8
Distributions to member	(118)	(112)
Contributions from member	487	405
Other financing activities	(21)	(17)
Net cash flows provided by financing activities	487	320
<b>Increase in cash, restricted cash, and cash equivalents</b>	323	23
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	204	373
<b>Cash, restricted cash, and cash equivalents at end of period</b>	\$ 527	\$ 396
<b>Supplemental cash flow information</b>		
Decrease in capital expenditures not paid	\$ (11)	\$ (76)

See the Combined Notes to Consolidated Financial Statements

**PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
(Unaudited)

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 504	\$ 180
Restricted cash and cash equivalents	23	24
Accounts receivable		
Customer accounts receivable	714	745
Customer allowance for credit losses	(105)	(107)
Customer accounts receivable, net	609	638
Other accounts receivable	321	310
Other allowance for credit losses	(57)	(50)
Other accounts receivable, net	264	260
Receivables from affiliates	4	3
Inventories, net		
Fossil fuel	3	9
Materials and supplies	304	287
Regulatory assets	342	337
Other	82	100
Total current assets	2,135	1,838
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$3,302 and \$3,175 as of March 31, 2024 and December 31, 2023, respectively)</b>	19,121	18,851
<b>Deferred debits and other assets</b>		
Regulatory assets	1,606	1,587
Goodwill	4,005	4,005
Investments	145	143
Prepaid pension asset	314	268
Other	209	211
Total deferred debits and other assets	6,279	6,214
<b>Total assets</b>	<b>\$ 27,535</b>	<b>\$ 26,903</b>

See the Combined Notes to Consolidated Financial Statements

**PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED BALANCE SHEETS**  
(Unaudited)

(In millions)	March 31, 2024	December 31, 2023
<b>LIABILITIES AND MEMBER'S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ —	\$ 394
Long-term debt due within one year	244	644
Accounts payable	668	683
Accrued expenses	344	338
Payables to affiliates	60	59
Borrowings from Exelon intercompany money pool	73	65
Customer deposits	104	100
Regulatory liabilities	89	71
Unamortized energy contract liabilities	7	8
PPA termination obligation	31	49
Other	108	138
Total current liabilities	1,728	2,549
<b>Long-term debt</b>	<b>8,909</b>	<b>8,004</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	3,071	3,031
Regulatory liabilities	878	904
Asset retirement obligations	56	55
Non-pension postretirement benefit obligations	37	40
Unamortized energy contract liabilities	25	27
Other	512	511
Total deferred credits and other liabilities	4,579	4,568
Total liabilities	15,216	15,121
<b>Commitments and contingencies</b>		
<b>Member's equity</b>		
Membership interest	12,544	12,057
Undistributed losses	(225)	(275)
Total member's equity	12,319	11,782
<b>Total liabilities and member's equity</b>	<b>\$ 27,535</b>	<b>\$ 26,903</b>

See the Combined Notes to Consolidated Financial Statements

**PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY**  
**(Unaudited)**

<i>(In millions)</i>	<b>Three Months Ended March 31, 2024</b>		
	<b>Membership Interest</b>	<b>Undistributed (Losses)/Gains</b>	<b>Total Member's Equity</b>
<b>Balance at December 31, 2023</b>	\$ 12,057	\$ (275)	\$ 11,782
Net income	—	168	168
Distributions to member	—	(118)	(118)
Contributions from member	487	—	487
<b>Balance at March 31, 2024</b>	<u>\$ 12,544</u>	<u>\$ (225)</u>	<u>\$ 12,319</u>

<i>(In millions)</i>	<b>Three Months Ended March 31, 2023</b>		
	<b>Membership Interest</b>	<b>Undistributed (Losses)/Gains</b>	<b>Total Member's Equity</b>
<b>Balance at December 31, 2022</b>	\$ 11,582	\$ (352)	\$ 11,230
Net income	—	155	155
Distributions to member	—	(112)	(112)
Contributions from member	405	—	405
<b>Balance at March 31, 2023</b>	<u>\$ 11,987</u>	<u>\$ (309)</u>	<u>\$ 11,678</u>

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
**(Unaudited)**

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Operating revenues</b>		
Electric operating revenues	\$ 728	\$ 670
Revenues from alternative revenue programs	29	39
Operating revenues from affiliates	2	1
Total operating revenues	759	710
<b>Operating expenses</b>		
Purchased power	281	258
Operating and maintenance	86	93
Operating and maintenance from affiliates	64	57
Depreciation and amortization	107	108
Taxes other than income taxes	102	94
Total operating expenses	640	610
<b>Operating income</b>	119	100
<b>Other income and (deductions)</b>		
Interest expense, net	(45)	(39)
Other, net	15	16
Total other income and (deductions)	(30)	(23)
<b>Income before income taxes</b>	89	77
<b>Income taxes</b>	14	12
<b>Net income</b>	\$ 75	\$ 65
<b>Comprehensive income</b>	\$ 75	\$ 65

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY**  
**STATEMENTS OF CASH FLOWS**  
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 75	\$ 65
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	107	108
Deferred income taxes and amortization of investment tax credits	3	3
Other non-cash operating activities	(13)	(10)
Changes in assets and liabilities:		
Accounts receivable	21	52
Receivables from and payables to affiliates, net	6	3
Inventories	(10)	(3)
Accounts payable and accrued expenses	—	(27)
Collateral paid, net	(1)	(25)
Income taxes	12	8
Regulatory assets and liabilities, net	6	(3)
Pension and non-pension postretirement benefit contributions	(4)	(4)
Other assets and liabilities	(19)	11
Net cash flows provided by operating activities	183	178
<b>Cash flows from investing activities</b>		
Capital expenditures	(229)	(264)
Changes in PHI intercompany money pool	(134)	—
Other investing activities	—	8
Net cash flows used in investing activities	(363)	(256)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(132)	(299)
Issuance of long-term debt	675	250
Retirement of long-term debt	(400)	—
Dividends paid on common stock	(51)	(48)
Contributions from parent	251	243
Other financing activities	(15)	(14)
Net cash flows provided by financing activities	328	132
<b>Increase in cash, restricted cash, and cash equivalents</b>	148	54
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	72	99
<b>Cash, restricted cash, and cash equivalents at end of period</b>	\$ 220	\$ 153
<b>Supplemental cash flow information</b>		
Decrease in capital expenditures not paid	\$ (11)	\$ (43)

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY**  
**BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 198	\$ 48
Restricted cash and cash equivalents	22	24
Accounts receivable		
Customer accounts receivable	349	369
Customer allowance for credit losses	(52)	(52)
Customer accounts receivable, net	297	317
Other accounts receivable	156	166
Other allowance for credit losses	(35)	(28)
Other accounts receivable, net	121	138
Receivables from affiliates	1	2
Receivable from PHI intercompany money pool	134	—
Inventories, net	169	159
Regulatory assets	133	150
Other	35	51
Total current assets	1,110	889
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,341 and \$4,284 as of March 31, 2024 and December 31, 2023, respectively)</b>	9,584	9,430
<b>Deferred debits and other assets</b>		
Regulatory assets	467	450
Investments	127	124
Prepaid pension asset	240	246
Other	57	55
Total deferred debits and other assets	891	875
<b>Total assets</b>	<b>\$ 11,585</b>	<b>\$ 11,194</b>

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY**  
**BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>LIABILITIES AND SHAREHOLDER'S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ —	\$ 132
Long-term debt due within one year	5	405
Accounts payable	304	321
Accrued expenses	209	191
Payables to affiliates	37	32
Customer deposits	49	47
Regulatory liabilities	23	15
Merger related obligation	23	25
Other	35	61
Total current liabilities	685	1,229
<b>Long-term debt</b>	4,354	3,691
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	1,448	1,431
Regulatory liabilities	368	382
Asset retirement obligations	38	37
Other	273	280
Total deferred credits and other liabilities	2,127	2,130
Total liabilities	7,166	7,050
<b>Commitments and contingencies</b>		
<b>Shareholder's equity</b>		
Common stock	3,326	3,075
Retained earnings	1,093	1,069
Total shareholder's equity	4,419	4,144
<b>Total liabilities and shareholder's equity</b>	<b>\$ 11,585</b>	<b>\$ 11,194</b>

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY**  
**STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY**  
**(Unaudited)**

<i>(In millions)</i>	Three Months Ended March 31, 2024		
	Common Stock	Retained Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2023</b>	\$ 3,075	\$ 1,069	\$ 4,144
Net income	—	75	75
Common stock dividends	—	(51)	(51)
Contributions from parent	251	—	251
<b>Balance at March 31, 2024</b>	<u>\$ 3,326</u>	<u>\$ 1,093</u>	<u>\$ 4,419</u>

<i>(In millions)</i>	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2022</b>	\$ 2,767	\$ 1,015	\$ 3,782
Net income	—	65	65
Common stock dividends	—	(48)	(48)
Contributions from parent	243	—	243
<b>Balance at March 31, 2023</b>	<u>\$ 3,010</u>	<u>\$ 1,032</u>	<u>\$ 4,042</u>

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**DELMARVA POWER & LIGHT COMPANY**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
**(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>March 31,</b>	
	<b>2024</b>	<b>2023</b>
<b>Operating revenues</b>		
Electric operating revenues	\$ 413	\$ 366
Natural gas operating revenues	72	97
Revenues from alternative revenue programs	4	9
Operating revenues from affiliates	2	2
Total operating revenues	491	474
<b>Operating expenses</b>		
Purchased power	186	166
Purchased fuel	29	55
Operating and maintenance	51	46
Operating and maintenance from affiliates	44	41
Depreciation and amortization	61	60
Taxes other than income taxes	20	20
Total operating expenses	391	388
<b>Operating income</b>	100	86
<b>Other income and (deductions)</b>		
Interest expense, net	(22)	(17)
Other, net	5	3
Total other income and (deductions)	(17)	(14)
<b>Income before income taxes</b>	83	72
<b>Income taxes</b>	17	12
<b>Net income</b>	\$ 66	\$ 60
<b>Comprehensive income</b>	\$ 66	\$ 60

See the Combined Notes to Consolidated Financial Statements

**DELMARVA POWER & LIGHT COMPANY**  
**STATEMENTS OF CASH FLOWS**  
**(Unaudited)**

<i>(In millions)</i>	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 66	\$ 60
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	61	60
Deferred income taxes and amortization of investment tax credits	6	3
Other non-cash operating activities	12	(1)
Changes in assets and liabilities:		
Accounts receivable	(7)	23
Receivables from and payables to affiliates, net	—	4
Inventories	1	10
Accounts payable and accrued expenses	16	(16)
Collateral paid, net	—	(120)
Income taxes	10	9
Regulatory assets and liabilities, net	(1)	27
Other assets and liabilities	6	1
Net cash flows provided by operating activities	<u>170</u>	<u>60</u>
<b>Cash flows from investing activities</b>		
Capital expenditures	(134)	(134)
Net cash flows used in investing activities	<u>(134)</u>	<u>(134)</u>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(63)	(115)
Issuance of long-term debt	175	125
Dividends paid on common stock	(45)	(42)
Contributions from parent	154	99
Other financing activities	(3)	(2)
Net cash flows provided by financing activities	<u>218</u>	<u>65</u>
<b>Increase (decrease) in cash, restricted cash, and cash equivalents</b>	<u>254</u>	<u>(9)</u>
<b>Cash, restricted cash, and cash equivalents at beginning of period</b>	<u>16</u>	<u>152</u>
<b>Cash, restricted cash, and cash equivalents at end of period</b>	<u>\$ 270</u>	<u>\$ 143</u>
<b>Supplemental cash flow information</b>		
Decrease in capital expenditures not paid	\$ (6)	\$ (3)

See the Combined Notes to Consolidated Financial Statements

**DELMARVA POWER & LIGHT COMPANY**  
**BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	March 31, 2024	December 31, 2023
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 269	\$ 16
Restricted cash and cash equivalents	1	—
Accounts receivable		
Customer accounts receivable	186	183
Customer allowance for credit losses	(17)	(19)
Customer accounts receivable, net	169	164
Other accounts receivable	51	52
Other allowance for credit losses	(8)	(8)
Other accounts receivable, net	43	44
Receivables from affiliates	—	1
Inventories, net		
Fossil fuel	3	9
Materials and supplies	77	72
Prepaid utility taxes	13	24
Regulatory assets	56	54
Other	20	14
Total current assets	651	398
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,961 and \$1,925 as of March 31, 2024 and December 31, 2023, respectively)</b>	5,245	5,165
<b>Deferred debits and other assets</b>		
Regulatory assets	212	218
Prepaid pension asset	132	135
Other	51	50
Total deferred debits and other assets	395	403
<b>Total assets</b>	<b>\$ 6,291</b>	<b>\$ 5,966</b>

See the Combined Notes to Consolidated Financial Statements

**DELMARVA POWER & LIGHT COMPANY**  
**BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	March 31, 2024	December 31, 2023
<b>LIABILITIES AND SHAREHOLDER'S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ —	\$ 63
Long-term debt due within one year	85	84
Accounts payable	157	159
Accrued expenses	86	64
Payables to affiliates	25	25
Customer deposits	32	31
Regulatory liabilities	61	50
Other	18	21
Total current liabilities	464	497
<b>Long-term debt</b>	2,169	1,996
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	919	904
Regulatory liabilities	356	365
Asset retirement obligations	13	12
Non-pension postretirement benefits obligations	5	6
Other	97	93
Total deferred credits and other liabilities	1,390	1,380
Total liabilities	4,023	3,873
<b>Commitments and contingencies</b>		
<b>Shareholder's equity</b>		
Common stock	1,609	1,455
Retained earnings	659	638
Total shareholder's equity	2,268	2,093
<b>Total liabilities and shareholder's equity</b>	<b>\$ 6,291</b>	<b>\$ 5,966</b>

See the Combined Notes to Consolidated Financial Statements

**DELMARVA POWER & LIGHT COMPANY**  
**STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY**  
**(Unaudited)**

<i>(In millions)</i>	Three Months Ended March 31, 2024		
	Common Stock	Retained Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2023</b>	\$ 1,455	\$ 638	\$ 2,093
Net income	—	66	66
Common stock dividends	—	(45)	(45)
Contributions from parent	154	—	154
<b>Balance at March 31, 2024</b>	<u>\$ 1,609</u>	<u>\$ 659</u>	<u>\$ 2,268</u>

<i>(In millions)</i>	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2022</b>	\$ 1,356	\$ 594	\$ 1,950
Net income	—	60	60
Common stock dividends	—	(42)	(42)
Contributions from parent	99	—	99
<b>Balance at March 31, 2023</b>	<u>\$ 1,455</u>	<u>\$ 612</u>	<u>\$ 2,067</u>

See the Combined Notes to Consolidated Financial Statements

**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
**(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>March 31,</b>	
	<b>2024</b>	<b>2023</b>
<b>Operating revenues</b>		
Electric operating revenues	\$ 344	\$ 335
Revenues from alternative revenue programs	13	17
Operating revenues from affiliates	1	1
Total operating revenues	358	353
<b>Operating expenses</b>		
Purchased power	140	148
Operating and maintenance	47	44
Operating and maintenance from affiliates	40	37
Depreciation and amortization	74	67
Taxes other than income taxes	2	2
Total operating expenses	303	298
<b>Operating income</b>	55	55
<b>Other income and (deductions)</b>		
Interest expense, net	(20)	(16)
Other, net	5	5
Total other income and (deductions)	(15)	(11)
<b>Income before income taxes</b>	40	44
<b>Income taxes</b>	11	11
<b>Net income</b>	\$ 29	\$ 33
<b>Comprehensive income</b>	\$ 29	\$ 33

See the Combined Notes to Consolidated Financial Statements

**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
**(Unaudited)**

(In millions)	Three Months Ended March 31,	
	2024	2023
<b>Cash flows from operating activities</b>		
Net income	\$ 29	\$ 33
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	74	67
Deferred income taxes and amortization of investment tax credits	7	6
Other non-cash operating activities	2	(9)
Changes in assets and liabilities:		
Accounts receivable	(12)	24
Receivables from and payables to affiliates, net	(5)	(1)
Inventories	(3)	(3)
Accounts payable and accrued expenses	(1)	(15)
Collateral received (paid), net	1	(44)
Income taxes	3	5
Regulatory assets and liabilities, net	(47)	3
Pension and non-pension postretirement benefit contributions	(7)	(1)
Other assets and liabilities	(13)	(21)
Net cash flows provided by operating activities	<u>28</u>	<u>44</u>
<b>Cash flows from investing activities</b>		
Capital expenditures	(89)	(161)
Net cash flows used in investing activities	<u>(89)</u>	<u>(161)</u>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(199)	—
Issuance of long-term debt	75	75
Changes in PHI intercompany money pool	134	—
Dividends paid on common stock	(22)	(21)
Contributions from parent	81	63
Other financing activities	(2)	(1)
Net cash flows provided by financing activities	<u>67</u>	<u>116</u>
<b>Increase (decrease) in cash and cash equivalents</b>	<u>6</u>	<u>(1)</u>
<b>Cash and cash equivalents at beginning of period</b>	<u>21</u>	<u>72</u>
<b>Cash and cash equivalents at end of period</b>	<u>\$ 27</u>	<u>\$ 71</u>
<b>Supplemental cash flow information</b>		
Increase (decrease) in capital expenditures not paid	\$ 4	\$ (30)

See the Combined Notes to Consolidated Financial Statements

**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED BALANCE SHEETS**  
**(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2024</u>	<u>December 31, 2023</u>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 27	\$ 21
Accounts receivable		
Customer accounts receivable	178	194
Customer allowance for credit losses	(36)	(36)
Customer accounts receivable, net	142	158
Other accounts receivable	115	92
Other allowance for credit losses	(14)	(14)
Other accounts receivable, net	101	78
Receivables from affiliates	4	3
Inventories, net	58	55
Regulatory assets	145	125
Other	7	5
Total current assets	484	445
<b>Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,702 and \$1,684 as of March 31, 2024 and December 31, 2023, respectively)</b>	4,232	4,192
<b>Deferred debits and other assets</b>		
Regulatory assets	497	483
Prepaid pension asset	6	3
Other	34	34
Total deferred debits and other assets	537	520
<b>Total assets</b>	<b>\$ 5,253</b>	<b>\$ 5,157</b>

See the Combined Notes to Consolidated Financial Statements

**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED BALANCE SHEETS**  
(Unaudited)

<u>(In millions)</u>	March 31, 2024	December 31, 2023
<b>LIABILITIES AND SHAREHOLDER'S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ —	\$ 199
Long-term debt due within one year	154	154
Accounts payable	195	192
Accrued expenses	45	42
Payables to affiliates	22	25
Borrowings from PHI intercompany money pool	134	—
Customer deposits	23	23
Regulatory liabilities	5	6
PPA termination obligation	31	49
Other	11	12
Total current liabilities	<u>620</u>	<u>702</u>
<b>Long-term debt</b>	1,755	1,679
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	780	771
Regulatory liabilities	137	140
Non-pension postretirement benefit obligations	3	4
Other	58	49
Total deferred credits and other liabilities	<u>978</u>	<u>964</u>
Total liabilities	<u>3,353</u>	<u>3,345</u>
<b>Commitments and contingencies</b>		
<b>Shareholder's equity</b>		
Common stock	1,911	1,830
Retained deficit	(11)	(18)
Total shareholder's equity	<u>1,900</u>	<u>1,812</u>
<b>Total liabilities and shareholder's equity</b>	<u>\$ 5,253</u>	<u>\$ 5,157</u>

See the Combined Notes to Consolidated Financial Statements

**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY**  
**(Unaudited)**

<i>(In millions)</i>	Three Months Ended March 31, 2024		
	Common Stock	Retained (Deficit)	Total Shareholder's Equity
<b>Balance at December 31, 2023</b>	\$ 1,830	\$ (18)	\$ 1,812
Net income	—	29	29
Common stock dividends	—	(22)	(22)
Contributions from parent	81	—	81
<b>Balance at March 31, 2024</b>	<u>\$ 1,911</u>	<u>\$ (11)</u>	<u>\$ 1,900</u>

<i>(In millions)</i>	Three Months Ended March 31, 2023		
	Common Stock	Retained (Deficit) Earnings	Total Shareholder's Equity
<b>Balance at December 31, 2022</b>	\$ 1,765	\$ (12)	\$ 1,753
Net income	—	33	33
Common stock dividends	—	(21)	(21)
Contributions from parent	63	—	63
<b>Balance at March 31, 2023</b>	<u>\$ 1,828</u>	<u>\$ —</u>	<u>\$ 1,828</u>

See the Combined Notes to Consolidated Financial Statements

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 1 — Significant Accounting Policies

## 1. Significant Accounting Policies (All Registrants)

### Description of Business

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE.

Name of Registrant	Business	Service Territories
<b>Commonwealth Edison Company</b>	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
<b>PECO Energy Company</b>	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
<b>Baltimore Gas and Electric Company</b>	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
<b>Pepco Holdings LLC</b>	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
<b>Potomac Electric Power Company</b>	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland
	Transmission and distribution of electricity to retail customers	
<b>Delmarva Power &amp; Light Company</b>	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
<b>Atlantic City Electric Company</b>	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

### Basis of Presentation

This is a combined quarterly report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, finance, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon's corporate operations are presented as "Other" in the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

The accompanying consolidated financial statements as of March 31, 2024 and for the three months ended March 31, 2024 and 2023 are unaudited but, in the opinion of each Registrant's management, the Registrants include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2023 Consolidated Balance Sheets were derived from audited financial statements. The interim financial statements are to be read in conjunction with prior annual financial statements and notes. Additionally, financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2024. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 1 — Significant Accounting Policies

statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

**New Accounting Standards (All Registrants)**

**New Accounting Standards Issued and Not Yet Adopted as of March 31, 2024:** The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements as of March 31, 2024. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) in their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact the Registrants' financial reporting.

*Segment Reporting (Issued November 2023).* Improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The objective of the revised guidance is to introduce a new requirement to disclose significant segment expenses regularly provided to the CODM, extend certain annual disclosures to interim periods, clarify single reportable segment entities must apply ASC 280 in its entirety, permit more than one measure of segment profit or loss to be reported under certain conditions, and require disclosure of the title and position of the CODM. The standard is effective for annual periods beginning January 1, 2024 and interim periods beginning January 1, 2025, with early adoption permitted. The standard will be applied retrospectively.

*Improvement to Income Tax Disclosures (Issued December 2023).* Provides additional disclosure requirements related to the effective tax rate reconciliation and income taxes paid. Under the revised guidance for the effective tax reconciliations, entities would be required to disclose: (1) eight specific categories in the effective tax rate reconciliation in both percentages and reporting currency amount, (2) additional information for reconciling items over a certain threshold, (3) explanation of individual reconciling items disclosed, and (4) provide a qualitative description of the state and local jurisdictions that contribute to the majority of the state income tax expense. For each annual period presented, the new standard requires disclosure of the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign. It also requires additional disaggregated information on income taxes paid (net of refunds received) to an individual jurisdiction equal to or greater than 5% of total income taxes paid (net of refunds received). The standard is effective January 1, 2025, with early adoption permitted.

**2. Regulatory Matters (All Registrants)**

As discussed in Note 3 — Regulatory Matters of the 2023 Form 10-K, the Registrants are involved in rate and regulatory proceedings at FERC and their state commissions. The following discusses developments in 2024 and updates to the 2023 Form 10-K.

**Distribution Base Rate Case Proceedings**

The following tables show the completed and pending distribution base rate case proceedings in 2024.

***Completed Distribution Base Rate Case Proceedings***

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	January 17, 2023	Electric	\$ 1,487	\$ 501	8.905%	December 14, 2023 <sup>(a)</sup>	January 1, 2024
			\$ 838	\$ 810	8.905%	April 18, 2024 <sup>(b)</sup>	May 1, 2024
	April 21, 2023 <sup>(c)</sup>	Electric	\$ 247	\$ 259	8.91%	November 30, 2023	January 1, 2024
BGE - Maryland <sup>(d)</sup>	February 17, 2023	Electric	\$ 313	\$ 179	9.50%	December 14, 2023	January 1, 2024
		Natural Gas	\$ 289	\$ 229	9.45%		
Pepco - Maryland <sup>(e)</sup>	October 26, 2020 (amended March 31, 2021)	Electric	\$ 104	\$ 52	9.55%	June 28, 2021	June 28, 2021
DPL - Maryland <sup>(f)</sup>	May 19, 2022	Electric	\$ 38	\$ 29	9.60%	December 14, 2022	January 1, 2023
DPL - Delaware	December 15, 2022 (amended September 29, 2023)	Electric	\$ 39	\$ 28	9.60%	April 18, 2024	July 15, 2023
ACE - New Jersey <sup>(g)</sup>	February 15, 2023 (amended August 21, 2023)	Electric	\$ 92	\$ 45	9.60%	November 17, 2023	December 1, 2023

- (a) Reflects a four-year cumulative multi-year rate plan for January 1, 2024 to December 31, 2027. On December 14, 2023, the ICC approved year-over-year distribution revenue requirement increases in 2024-2027, with an amendatory order on January 10, 2024, of approximately \$451 million effective January 1, 2024, \$14 million effective January 1, 2025, \$6 million effective January 1, 2026, and \$30 million effective January 1, 2027, based on an ROE of 8.905%, an equity ratio of 50%, and year end 2022 rate base. The ICC rejected ComEd's Grid Plan, requiring ComEd to file a revised Grid Plan by March 13, 2024, 90 days after the issuance of the December final order. The ICC also directed that the revised Grid Plan would be reviewed through further formal proceedings in that docket. On January 10, 2024, the ICC granted one portion of ComEd's application for rehearing of the December 14, 2023 final order, and directed that a rehearing process extending no more than 150 days reconsider certain components of the revenue requirements for the test years (2024-2027), absent an approved Grid Plan. On January 10, 2024, ComEd also filed with the Illinois appellate court an appeal of various aspects of the ICC's final order on which rehearing was denied, including the 8.905% ROE and 50% equity ratio and denial of any return on ComEd's pension asset. On March 13, 2024, ComEd filed its revised Grid Plan (Refiled Grid Plan) with supporting testimony and schedules with the ICC. On March 15, 2024, ComEd filed a petition to adjust its MRP to authorize increased rates consistent with the Refiled Grid Plan.
- (b) Reflects four-year cumulative increase to the revenue requirement approved on December 14, 2023 and amended on January 10, 2024 of \$810 million for January 1, 2024 to December 31, 2027 resulting from the rehearing on certain components of the rate plan. On February 16, 2024, ComEd filed a revised revenue request for an \$838 million increase in its 2024-2027 revenue requirements based on the ICC's limited scope for rehearing which included the value of the 2023 forecasted year-end rate base. On April 18, 2024, the ICC issued an order on the rehearing filing which increased the revenue requirements previously approved by the ICC in its January 10, 2024, amendatory order by \$150 million in 2024, \$186 million in 2025, \$221 million in 2026 and \$253 million in 2027. ComEd anticipates that the revenue requirements determined during the rehearing process will be further adjusted upon approval of the Refiled Grid Plan and the pending petition to adjust rates.
- (c) On November 30, 2023, the Delivery Reconciliation Amount for 2022 defined in Rider Delivery Service Pricing Reconciliation (Rider DSPR) was approved. The delivery reconciliation amount allows for the reconciliation of the revenue requirement in effect in the final years in which formula rates are determined and until such time as new rates are established under ComEd's approved MRP. The 2023 filing reconciled the delivery service rates in effect in 2022 with the actual delivery service costs incurred in 2022. The reconciliation revenue requirement provides for a weighted average debt and equity return on distribution rate base of 6.48%, inclusive of an allowed ROE of 8.91%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points.
- (d) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026. The MDPSC awarded BGE electric revenue requirement increases of \$41 million, \$113 million, and \$25 million in 2024, 2025, and 2026,

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

respectively, and natural gas revenue requirement increases of \$126 million, \$62 million, and \$41 million in 2024, 2025, and 2026, respectively. Requested revenue requirement increases will be used to recover capital investments designed to increase the resilience of the electric and gas distribution systems and support Maryland's climate and regulatory initiatives. The MDPSC also approved a portion of the requested 2021 and 2022 reconciliation amounts, which will be recovered through separate electric and gas riders between March 2024 through February 2025. As such, the reconciliation amounts are not included in the approved revenue requirement increases. The 2021 reconciliation amounts are \$13 million and \$7 million for electric and gas, respectively, and the 2022 reconciliation amounts are \$39 million and \$15 million for electric and gas, respectively. In April 2024, BGE filed with the MDPSC its request for recovery of the 2023 reconciliation amounts of \$79 million and \$73 million for electric and gas, respectively, with supporting testimony and schedules.

- (e) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. The MDPSC awarded Pepco electric incremental revenue requirement increases of \$21 million, \$16 million, and \$15 million, before offsets, for the 12-month periods ending March 31, 2022, 2023, and 2024, respectively. Pepco proposed to utilize certain tax benefits to fully offset the increase through 2023 and partially offset customer rate increases in 2024. However, the MDPSC only utilized the acceleration of refunds for certain tax benefits to fully offset the increases such that customer rates remain unchanged through March 31, 2022. On February 23, 2022, the MDPSC chose to offset 25% of the cumulative revenue requirement increase for the 12-month period ending March 31, 2023. In 2021, the MDPSC deferred a decision on whether to use certain tax benefits to offset the revenue requirement increases for the 12-month period ending March 31, 2024. In December 2022 Pepco proposed that tax benefits not be used to offset the revenue requirement increases for this period. On January 25, 2023, the MDPSC accepted Pepco's recommendations not to use tax benefits to offset revenue requirement increases for the 12-month period ending March 31, 2024.
- (f) Reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025. The MDPSC awarded DPL electric incremental revenue requirement increases of \$17 million, \$6 million, and \$6 million for 2023, 2024, and 2025, respectively.
- (g) Requested and approved increases are before New Jersey sales and use tax. The NJBPU awarded ACE electric revenue requirement increases of \$36 million and \$9 million effective December 1, 2023 and February 1, 2024, respectively.

***Pending Distribution Base Rate Case Proceedings***

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois	March 15, 2024	Electric <sup>(a)</sup>	\$ 670	8.905%	December 2024
	April 26, 2024	Electric <sup>(b)</sup>	\$ 627	9.89%	December 2024
PECO - Pennsylvania	March 28, 2024	Electric <sup>(c)</sup>	\$ 464	10.95%	Fourth quarter of 2024
		Natural Gas	\$ 111	11.15%	
Pepco - District of Columbia <sup>(d)</sup>	April 13, 2023 (amended February 27, 2024)	Electric	\$ 186	10.50%	Third quarter of 2024
Pepco - Maryland <sup>(e)</sup>	May 16, 2023 (amended February 23, 2024)	Electric	\$ 186	10.50%	Second quarter of 2024

- (a) On March 13, 2024, ComEd filed its Refiled Grid Plan with the ICC and on March 15, 2024, ComEd filed a petition to adjust its multi-year rate plan to be aligned with ComEd's Refiled Grid Plan. The adjusted rate plan incorporates changes in the Refiled Grid Plan, which seeks a \$670 million increase in revenue requirements over four years above those granted in the ICC's January 10, 2024, amendatory order. The requested year-over-year increases are \$302 million in 2024, \$89 million in 2025, \$136 million in 2026 and \$143 million in 2027. A final order on both the Refiled Grid Plan and the adjusted rate plan petition is expected by December 2024 with new rates effective January 1, 2025.
- (b) On April 26, 2024, ComEd filed its proposed Delivery Reconciliation Amount of \$627 million under Rider DSPR which allows for the reconciliation of the revenue requirement in effect. The 2024 filing reconciles those rates with the actual delivery service costs incurred in 2023. Final order is expected by December 2024 and the reconciliation amount will adjust customer rates in 2025.
- (c) PECO requested an annual electric revenue requirement increase of \$464 million, which is partially offset by a one-time credit of \$64 million in 2025.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

- (d) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026 submitted to the DCPSC. Pepco requested total electric revenue requirement increases of \$116 million, \$35 million, and \$35 million in 2024, 2025, and 2026, respectively. Requested revenue requirement increases will be used to recover capital investments designed to advance system-readiness and support the District of Columbia’s climate and clean energy goals.
- (e) Reflects a three-year cumulative multi-year plan for April 1, 2024 through March 31, 2027 submitted to the MDPSC. Pepco requested total electric revenue requirement increases of \$68 million, \$53 million, and \$51 million effective April 1, 2024, April 1, 2025, and April 1, 2026, respectively through its surrebuttal filing made on February 23, 2024. The plan contains a proposed nine-month extension period with a requested revenue requirement increase of \$14 million effective April 1, 2027 through December 31, 2027. Requested revenue requirement increases will be used to recover capital investments designed to advance system-readiness and support Maryland’s climate and clean energy goals. On August 7, 2023, the MDPSC issued an order approving a settlement agreement which allows Pepco to establish a revenue deferral mechanism to recover its full Commission-authorized year 1 increase between July 1, 2024 through March 31, 2025 and extend the procedural schedule to address intervenor resource constraints.

**Transmission Formula Rates**

The Utility Registrants’ transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for ComEd is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The update for ComEd 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). The annual update for BGE is based on prior year actual costs and current year projected capital additions, accumulated depreciation, depreciation and amortization expense, and accumulated deferred income taxes. The update for BGE also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2024, the following increases/(decreases) were included in ComEd’s and BGE’s electric transmission formula rate updates:

Registrant <sup>(a)</sup>	Initial Revenue Requirement Increase	Annual Reconciliation (Decrease) Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base <sup>(b)</sup>	Allowed ROE <sup>(c)</sup>
ComEd	\$ 32	\$ (12)	\$ 20	8.14 %	11.50 %
BGE	\$ 42	\$ 13	\$ 53 <sup>(d)</sup>	7.47 %	10.50 %

- (a) All rates are effective June 1, 2024 - May 31, 2025, subject to review by interested parties pursuant to review protocols of ComEd’s and BGE’s tariffs.
- (b) Represents the weighted average debt and equity return on transmission rate bases.
- (c) The rate of return on common equity for ComEd and BGE includes a 50-basis-point incentive adder for being a member of a RTO.
- (d) The increase in BGE’s transmission revenue requirement includes a \$2 million reduction related to a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.

**Other State Regulatory Matters**

**Illinois Regulatory Matters**

**CEJA (Exelon and ComEd).** On September 15, 2021, the Governor of Illinois signed into law CEJA. CEJA includes, among other features, (1) procurement of CMCs from qualifying nuclear-powered generating facilities, (2) a requirement to file a general rate case or a new four-year MRP no later than January 20, 2023 to establish rates effective after ComEd’s existing performance-based distribution formula rate sunsets, (3) requirements that ComEd and the ICC initiate and conduct various regulatory proceedings on subjects including ethics, spending, grid investments, and performance metrics.

**ComEd Electric Distribution Rates**

ComEd filed, and received approval for, its last performance-based electric distribution formula rate update under EIMA in 2022; those rates were in effect throughout 2023.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

On February 3, 2022, the ICC approved a tariff that establishes the process under which ComEd reconciled its 2022 and will reconcile its 2023 rate year revenue requirements with actual costs. Those reconciliation amounts are determined using the same process used for prior reconciliations under the performance-based electric distribution formula rate. Using that process, for the rate years 2022 and 2023 ComEd will ultimately collect revenues from customers reflecting each year's actual recoverable costs, year-end rate base, and a weighted average debt and equity return on distribution rate base, with the ROE component based on the annual average of the monthly yields of the 30-year U.S. Treasury bonds plus 580 basis points. In April 2023, ComEd filed its first petition with the ICC to reconcile its 2022 actual costs with the approved revenue requirement that was in effect in 2022; the final order was issued on November 30, 2023, for rates beginning January 2024. On April 26, 2024, ComEd filed with the ICC its 2023 actual costs with the approved revenue requirement that was in effect in 2023; the final order is expected by December 2024, for rates beginning January 2025.

Beginning in 2024, ComEd will recover from retail customers, subject to certain exceptions, the costs it incurs to provide electric delivery services either through its electric distribution rate or other recovery mechanisms authorized by CEJA. On January 17, 2023, ComEd filed a petition with the ICC seeking approval of a MRP for 2024-2027. The MRP supports a multi-year grid plan (Grid Plan), also filed on January 17, covering planned investments on the electric distribution system within ComEd's service area through 2027. Costs incurred during each year of the MRP are subject to ICC review and the plan's revenue requirement for each year will be reconciled with the actual costs that the ICC determines are prudently and reasonably incurred for that year. The reconciliation is subject to adjustment for certain costs, including a limitation on recovery of costs that are more than 105% of certain costs in the previously approved MRP revenue requirement, absent a modification of the rate plan itself. Thus, for example, the rate adjustments necessary to reconcile 2024 revenues to ComEd's actual 2024 costs incurred would take effect in January 2026 after the ICC's review during 2025. On May 22, 2023, direct testimony was filed by ICC staff and more than a dozen intervenors and intervenor groups. The testimonies addressed a wide variety of topics, including rate of return on equity, capital structure, grid planning, various distribution grid and information technology investments, and affordability and customer service. ComEd filed rebuttal testimony in June, which provided, among other things, defense of ComEd's planned 2024-2027 capital investment and proposed cost of equity. ComEd also made voluntary adjustments and, per the ICC's final beneficial electrification order requiring ComEd to recover beneficial electrification costs through the MRP, increased its total revenue requirement request from \$1.472 billion to \$1.545 billion. ComEd filed its reply brief on September 27, 2023, to adjust its total requested revenue requirement increase to \$1.487 billion.

On December 14, 2023, the ICC issued a final order. The ICC rejected ComEd's Grid Plan as non-compliant with certain requirements of CEJA, and required ComEd to file a revised Grid Plan by March 13, 2024, 90 days after the issuance of the final order. In the absence of an approved Grid Plan, the ICC set ComEd's forecast revenue requirements for 2024-2027 based on ComEd's approved year-end 2022 rate base. This results in a total cumulative revenue requirement increase of \$501 million, a \$986 million total revenue reduction from the requested cumulative revenue requirement increase but remains subject to annual reconciliation in accordance with CEJA. The final order approved the process and formulas associated with the MRP reconciliation mechanisms. The ICC did not approve a previously proposed phase-in of the ICC's approved year-over-year revenue increases, and it also denied ComEd's ability to earn a return on its pension asset.

On December 22, 2023, ComEd filed an application for rehearing on several findings in the final order including the use of the 2022 year-end rate base to establish forecast revenue requirements for 2024-2027, ROE, pension asset return, and capital structure. On January 10, 2024, ComEd's application for rehearing was denied on all issues except for the order's use of the 2022 year-end rate base. On January 31, 2024, the ICC granted ComEd's motion seeking additional clarification on the scope on rehearing, generally accepting ComEd's proposal and confirming that the rehearing will determine if the forecasted year-end 2023 rate base should be used to set rates for 2024 through 2027 until a refiled Grid Plan is approved. A final rehearing order on that topic is statutorily required by early June 2024. On April 18, 2024, the ICC issued its final order on rehearing and approved increased revenue requirements for 2024-2027.

On January 10, 2024, ComEd also filed an appeal in the Illinois Appellate Court of the issues on which rehearing was denied, including but not limited to the allowed ROE and denial of a return on ComEd's pension asset. There is no deadline by when the appellate court must rule. On March 7, 2024, the ICC adopted an interim order on scheduling, which confirmed that it intends to issue a final order on ComEd's Refiled Grid Plan by the end of 2024 and that it will implement rates that will go into effect January 1, 2025, inclusive of a Grid Plan. On March 13, 2024, ComEd filed its Refiled Grid Plan with supporting testimony and schedules with the ICC. The Refiled Grid Plan is designed to meet or exceed every requirement identified by the ICC in its December order that

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

rejected ComEd's initial Grid Plan. On March 15, 2024, ComEd filed a petition to adjust its MRP to authorize increased rates consistent with the Refiled Grid Plan. ComEd has completed and placed in service additional utility plant assets in 2023 and 2024 and will continue to complete and place in service additional utility plant assets prior to the approval of the new Grid Plan. There are still significant unknowns, but ComEd does not currently believe that it is probable that the initially uncollected depreciation or return on the recently completed plant will ultimately be disallowed.

In January 2022, ComEd filed a request with the ICC proposing performance metrics that would be used in determining ROE incentives and penalties in the event ComEd filed a MRP in January 2023. On September 27, 2022, the ICC issued a final order approving seven performance metrics that provide symmetrical performance adjustments of 32 total basis points to ComEd's rate of return on common equity based on the extent to which ComEd achieves the annual performance goals. On November 10, 2022, the ICC granted ComEd's application for rehearing, in part. On April 5, 2023, the ICC issued its final order on rehearing for the performance and tracking metrics proceeding, in which the ICC declined to adopt ComEd's proposed modifications to the reliability and peak load reduction performance metrics. Efforts are underway to implement the performance metrics, which took effect on January 1, 2024. ComEd will make its initial filing in 2025 to assess performance achieved under the metrics in 2024, and to determine any ROE adjustment, which would take effect in 2026.

*Carbon Mitigation Credit*

CEJA establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. ComEd is required to purchase CMCs from participating nuclear-powered generating facilities between June 1, 2022 and May 31, 2027. The price to be paid for each CMC was established through a competitive bidding process that included consumer-protection measures that capped the maximum acceptable bid amount and a formula that reduces CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy if applicable. The consumer protection measures contained in CEJA will result in net payments to ComEd ratepayers if the energy index, the capacity price and applicable federal tax credits or subsidy exceed the CMC contract price. In the June 2022 billing period, ComEd began issuing credits to its retail customers under its new CMC rider. A regulatory asset is recorded for the difference between customer credits issued and the credit to be received from the participating nuclear-powered generating facilities. The balance as of March 31, 2024 is \$405 million.

Under CEJA, the costs of procuring CMCs, including carrying costs, are recovered through a rider, the Rider Carbon-Free Resource Adjustment (Rider CFRA). As originally approved by the ICC, Rider CFRA provides for an annual reconciliation and true-up to actual costs incurred or credits received by ComEd to purchase CMCs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods. The difference between the net payments to (or receivables from) ComEd ratepayers and the credits received by ComEd to purchase CMCs is recorded to Purchased power expense with an offset to the regulatory asset (or regulatory liability). On December 21, 2022, ComEd filed an amendment to Rider CFRA proposing that it recover costs or provide credits faster than the tariff allows, implement monthly reconciliations, and allow ComEd to adjust Rider CFRA rates based not only on anticipated differences but also past payments or credits, and implement monthly reconciliations beginning the June 2023 delivery period. The ICC approved the proposal on January 19, 2023. In addition, on March 24, 2023, ComEd submitted revisions to Rider CFRA which clarified the methodology for calculating interest to be included in the annual reconciliation associated with the June 2022 through May 2023 delivery year. The ICC approved the proposal on April 20, 2023. On February 2, 2024, ComEd filed a petition with the ICC to initiate the reconciliation proceeding for the costs incurred in connection with the procurement of CMCs during the delivery year beginning June 1, 2022 and extending through May 31, 2023.

*Beneficial Electrification Plan*

On March 23, 2023, the ICC issued its final order approving the beneficial electrification plan for ComEd. The ICC rejected ComEd's request to treat a large portion of beneficial electrification costs as a regulatory asset and ordered ComEd to seek cost recovery through the multi-year rate plan filing for 2024 and 2025, and the final formula rate reconciliation docket for 2023, rather than through a separate charge. The order also authorized an overall annual budget of \$77 million per year for the three-year plan period (2023 through 2025), with flexibility to roll forward unused funds to future years within the same plan period. On April 18, 2023, ComEd filed an application for rehearing in the beneficial electrification plan docket. The Chicago Transit Authority and City of Chicago, jointly, and the Office of the Illinois Attorney General (ILAG) also filed applications for rehearing. On

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

April 27, 2023, ICC staff filed a motion for clarification, seeking clarification from the ICC on the precise budget described in the final order. On May 8, 2023, the ICC denied all applications for rehearing, and entered an amendatory order regarding the annual beneficial electrification plan budgets. ComEd has been directed to use good faith efforts to spend \$77 million annually. ComEd subsequently filed its compliance filing in May 2023, detailing project related spending, clarifying the procedure that will be used to seek stakeholder feedback related to beneficial electrification pilot programs, and including the timeline for tariff changes required to implement the programs. ComEd and the ILAG both filed appeals of the ICC's interim order that addressed the permissible scope of utility beneficial electrification programs outside of transportation and the rate impact cap. The ILAG also filed an appeal seeking reversal of portions of the ICC's final decision. The final order partly mooted ComEd's appeal of the interim order and ComEd has decided not to pursue the other issues. As such, ComEd moved to voluntarily dismiss its appeal and the appellate court granted that request. The ILAG consolidated their appeals and filed their opening brief on April 16, 2024. Any ruling on the appeals, even a negative ruling removing programs from the BE Plan or lowering the overall budget of the BE Plan, will only impact forward-looking costs.

*Energy Efficiency*

CEJA extends ComEd's current cumulative annual energy efficiency MWh savings goals through 2040, adds expanded electrification measures to those goals, increases low-income commitments and adds a new performance adjustment to the energy efficiency formula rate. ComEd expects its annual spend to increase in 2023 through 2040 to achieve these energy efficiency MWh savings goals, which will be deferred as a separate regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures.

***New Jersey Regulatory Matters***

***Termination of Energy Procurement Provisions of PPAs (Exelon, PHI, and ACE).*** On December 22, 2021, ACE filed with the NJBPU a petition to terminate the provisions in the PPAs to purchase electricity from two coal-powered generation facilities located in the state of New Jersey. The petition was approved by the NJBPU on March 23, 2022. Upon closing of the transaction on March 31, 2022, ACE recognized a liability of \$203 million for the contract termination fee, which is to be paid by the end of 2024, and recognized a corresponding regulatory asset of \$203 million.

As of March 31, 2024, the \$31 million liability for the contract termination fee is included in Other current liabilities in Exelon's Consolidated Balance Sheet and PPA termination obligation in PHI's and ACE's Consolidated Balance Sheets. For the three months ended March 31, 2024 and 2023, ACE has respectively paid \$18 million and \$19 million of the liability, which is recorded in Changes in Other assets and liabilities in Exelon's, PHI's, and ACE's Consolidated Statements of Cash Flows.

***Other Federal Regulatory Matters***

***FERC Audit (Exelon and ComEd).*** The Utility Registrants are subject to periodic audits and investigations by FERC. FERC's Division of Audits and Accounting initiated a nonpublic audit of ComEd in April 2021 evaluating ComEd's compliance with (1) approved terms, rates and conditions of its federally regulated service; (2) accounting requirements of the Uniform System of Accounts; (3) reporting requirements of the FERC Form 1; and (4) the requirements for record retention. The audit period extends back to January 1, 2017.

On July 27, 2023, FERC issued a final audit report which included, among other things, findings and recommendations related to ComEd's methodology regarding the allocation of certain overhead costs to capitalized construction costs under FERC regulations, including a suggestion that refunds may be due to customers for amounts collected in previous years. On August 28, 2023, ComEd filed a formal notice of the issues it will contest. On December 14, 2023, FERC appointed a settlement judge for the contested overhead allocation findings and set the matter for a trial-type hearing. That hearing process has been held in abeyance while a formal settlement process, which began in February 2024, takes place. Based on the preliminary findings and the ongoing settlement process, ComEd determined that a loss was probable and recorded its regulatory liability to reflect its best estimate of that loss. The final outcome and resolution of any contested audit issues as well as a reasonable estimate of potential future losses cannot be accurately estimated at this stage; however, the final resolution of these matters could result in recognition of future losses, above the amounts currently accrued, that could be material to the Exelon and ComEd financial statements.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 2 — Regulatory Matters

**Regulatory Assets and Liabilities**

The Utility Registrants' regulatory assets and liabilities have not changed materially since December 31, 2023, unless noted below. See Note 3 — Regulatory Matters of the 2023 Form 10-K for additional information on the specific regulatory assets and liabilities.

**ComEd.** Regulatory assets decreased \$286 million primarily due to a decrease of \$268 million in the CMC regulatory asset.

**PECO.** Regulatory liabilities increased \$17 million primarily due to an increase of \$26 million in the Decommissioning the regulatory agreement units regulatory liability.

**BGE.** Regulatory liabilities decreased \$75 million primarily due to a decrease of \$75 million in the Deferred income taxes regulatory liability.

**ACE.** Regulatory assets increased \$34 million primarily due to an increase of \$13 million in the Under-recovered revenue decoupling regulatory asset, an increase of \$8 million in the Energy efficiency and demand response programs regulatory asset, and an increase of \$8 million in the Deferred storm costs regulatory asset.

**Capitalized Ratemaking Amounts Not Recognized**

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes in the Registrants' Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to the Utility Registrants' customers. PECO had no related amounts at March 31, 2024 and December 31, 2023.

	Exelon	ComEd <sup>(a)</sup>	BGE <sup>(b)</sup>	PHI	Pepco <sup>(c)</sup>	DPL <sup>(c)</sup>	ACE <sup>(d)</sup>
March 31, 2024	\$ 106	\$ 36	\$ 30	\$ 40	\$ 27	\$ 1	\$ 12
December 31, 2023	110	32	33	45	34	1	10

- (a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its energy efficiency and electric distribution formula rate regulatory assets.
- (b) BGE's amount capitalized for ratemaking purposes primarily relates to earnings on shareholders' investment on their AMI programs and on investments in rate base included in the multi-year plan reconciliations.
- (c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI programs and Energy efficiency and demand response programs, and for Pepco District of Columbia revenue decoupling program. The earnings on energy efficiency are on Pepco District of Columbia and DPL Delaware programs only.
- (d) ACE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on AMI programs.

**3. Revenue from Contracts with Customers (All Registrants)**

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. The primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services.

See Note 4 — Revenue from Contracts with Customers of the 2023 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

**Contract Liabilities**

The Registrants record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. The Registrants record contract liabilities in Other current liabilities and Other noncurrent deferred credits and other liabilities in their Consolidated Balance Sheets.

For Pepco, DPL, and ACE these contract liabilities primarily relate to upfront consideration received in the third quarter of 2020 for a collaborative arrangement ("Agreement") with an unrelated owner and manager of communication infrastructure, as well as additional consideration received for the payment option amendment

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(a)

(a)

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(a)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 3 — Revenue from Contracts with Customers

("Amendment") executed during the fourth quarter of 2023, which is discussed in further detail within Note 4 — Revenue from Contracts with Customers of the 2023 Form 10-K. The contract liability balance attributable to the Agreement and the Amendment is being recognized as Electric operating revenues over a 35 year period and 31 year period, respectively.

The following table provides a rollforward of the contract liabilities reflected in Exelon's, PHI's, Pepco's, DPL's, and ACE's Consolidated Balance Sheets for the three months ended March 31, 2024 and 2023. At March 31, 2024 and December 31, 2023, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

	Exelon <sup>(a)</sup>	PHI <sup>(a)</sup>	Pepco <sup>(a)</sup>	DPL	ACE
Balance at December 31, 2023	\$ 133	\$ 133	\$ 107	\$ 13	\$ 13
Revenues recognized	(2)	(2)	(2)	—	—
Balance at March 31, 2024	<u>\$ 131</u>	<u>\$ 131</u>	<u>\$ 105</u>	<u>\$ 13</u>	<u>\$ 13</u>
	Exelon <sup>(a)</sup>	PHI <sup>(a)</sup>	Pepco <sup>(a)</sup>	DPL	ACE
Balance at December 31, 2022	\$ 101	\$ 101	\$ 81	\$ 10	\$ 10
Revenues recognized	(1)	(1)	(1)	—	—
Balance at March 31, 2023	<u>\$ 100</u>	<u>\$ 100</u>	<u>\$ 80</u>	<u>\$ 10</u>	<u>\$ 10</u>

(a) Revenues recognized in the three months ended March 31, 2024 and 2023, were included in the contract liabilities at December 31, 2023 and 2022, respectively.

#### Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of March 31, 2024. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

This disclosure excludes the Utility Registrants' gas and electric tariff sales contracts and transmission revenue contracts as they generally have an original expected duration of one year or less and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure.

Year	Exelon	PHI	Pepco	DPL	ACE
2024	\$ 4	\$ 4	\$ 4	\$ —	\$ —
2025	7	7	5	1	1
2026	6	6	5	1	—
2027	5	5	5	—	—
2028 and thereafter	109	109	86	11	12
Total	<u>\$ 131</u>	<u>\$ 131</u>	<u>\$ 105</u>	<u>\$ 13</u>	<u>\$ 13</u>

#### Revenue Disaggregation

The Registrants disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 4 — Segment Information for the presentation of the Registrants' revenue disaggregation.

#### 4. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the CODMs in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has six reportable segments, which include ComEd, PECO, BGE, and PHI's three reportable segments consisting of Pepco, DPL, and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon,

(b)

(a)

(c)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 4 — Segment Information

ComEd, PECO, BGE, Pepco, DPL, and ACE's CODMs evaluate the performance of and allocate resources to the segments based on net income.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended March 31, 2024 and 2023 is as follows:

	ComEd	PECO	BGE	PHI	Other <sup>(a)</sup>	Intersegment Eliminations	Exelon
<b>Operating revenues<sup>(b)</sup>:</b>							
2024							
Electric revenues	\$ 2,095	\$ 782	\$ 881	\$ 1,532	\$ —	\$ (6)	\$ 5,284
Natural gas revenues	—	272	416	72	—	(1)	759
Shared service and other revenues	—	—	—	2	459	(461)	—
Total operating revenues	<u>\$ 2,095</u>	<u>\$ 1,054</u>	<u>\$ 1,297</u>	<u>\$ 1,606</u>	<u>\$ 459</u>	<u>\$ (468)</u>	<u>\$ 6,043</u>
2023							
Electric revenues	\$ 1,667	\$ 795	\$ 814	\$ 1,436	\$ —	\$ (5)	\$ 4,707
Natural gas revenues	—	317	443	97	—	(1)	856
Shared service and other revenues	—	—	—	3	437	(440)	—
Total operating revenues	<u>\$ 1,667</u>	<u>\$ 1,112</u>	<u>\$ 1,257</u>	<u>\$ 1,536</u>	<u>\$ 437</u>	<u>\$ (446)</u>	<u>\$ 5,563</u>
<b>Intersegment revenues<sup>(c)</sup>:</b>							
2024	\$ 2	\$ 2	\$ 2	\$ 3	\$ 457	\$ (466)	\$ —
2023	3	2	3	3	434	(445)	—
<b>Depreciation and amortization:</b>							
2024	\$ 362	\$ 104	\$ 150	\$ 246	\$ 17	\$ —	\$ 879
2023	338	98	167	241	16	—	860
<b>Operating expenses:</b>							
2024	\$ 1,781	\$ 851	\$ 967	\$ 1,335	\$ 472	\$ (475)	\$ 4,931
2023	1,256	902	964	1,297	485	(447)	4,457
<b>Interest expense, net:</b>							
2024	\$ 122	\$ 55	\$ 50	\$ 90	\$ 151	\$ —	\$ 468
2023	117	48	44	76	127	—	412
<b>Income taxes:</b>							
2024	\$ 19	\$ 10	\$ 24	\$ 40	\$ (30)	\$ —	\$ 63
2023	71	4	52	34	(27)	—	134
<b>Net income (loss):</b>							
2024	\$ 193	\$ 149	\$ 264	\$ 168	\$ (116)	\$ —	\$ 658
2023	241	166	200	155	(93)	—	669
<b>Capital expenditures:</b>							
2024	\$ 594	\$ 361	\$ 324	\$ 453	\$ 35	\$ —	\$ 1,767
2023	617	335	350	561	18	—	1,881
<b>Total assets:</b>							
March 31, 2024	\$ 43,132	\$ 16,116	\$ 14,444	\$ 27,535	\$ 6,376	\$ (4,392)	\$ 103,211
December 31, 2023	42,827	15,595	14,184	26,903	6,374	(4,337)	101,546

(a) Other primarily includes Exelon's corporate operations, shared service entities, and other financing and investment activities.

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(b)

(a)

(c)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 4 — Segment Information

- (b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in Taxes other than income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Supplemental Financial Information for additional information on total utility taxes.
- (c) See Note 15 — Related Party Transactions for additional information on intersegment revenues.

**PHI:**

	Pepco	DPL	ACE	Other <sup>(a)</sup>	Intersegment Eliminations	PHI
<b>Operating revenues<sup>(b)</sup>:</b>						
2024						
Electric revenues	\$ 759	\$ 419	\$ 358	\$ —	\$ (4)	\$ 1,532
Natural gas revenues	—	72	—	—	—	72
Shared service and other revenues	—	—	—	109	(107)	2
Total operating revenues	<u>\$ 759</u>	<u>\$ 491</u>	<u>\$ 358</u>	<u>\$ 109</u>	<u>\$ (111)</u>	<u>\$ 1,606</u>
2023						
Electric revenues	\$ 710	\$ 377	\$ 353	\$ —	\$ (4)	\$ 1,436
Natural gas revenues	—	97	—	—	—	97
Shared service and other revenues	—	—	—	102	(99)	3
Total operating revenues	<u>\$ 710</u>	<u>\$ 474</u>	<u>\$ 353</u>	<u>\$ 102</u>	<u>\$ (103)</u>	<u>\$ 1,536</u>
<b>Intersegment revenues<sup>(c)</sup>:</b>						
2024	\$ 2	\$ 2	\$ 1	\$ 109	\$ (111)	\$ 3
2023	1	2	1	102	(103)	3
<b>Depreciation and amortization:</b>						
2024	\$ 107	\$ 61	\$ 74	\$ 4	\$ —	\$ 246
2023	108	60	67	6	—	241
<b>Operating expenses:</b>						
2024	\$ 640	\$ 391	\$ 303	\$ 111	\$ (110)	\$ 1,335
2023	610	388	298	104	(103)	1,297
<b>Interest expense, net:</b>						
2024	\$ 45	\$ 22	\$ 20	\$ 3	\$ —	\$ 90
2023	39	17	16	4	—	76
<b>Income taxes:</b>						
2024	\$ 14	\$ 17	\$ 11	\$ (2)	\$ —	\$ 40
2023	12	12	11	(1)	—	34
<b>Net income (loss):</b>						
2024	\$ 75	\$ 66	\$ 29	\$ (2)	\$ —	\$ 168
2023	65	60	33	(3)	—	155
<b>Capital expenditures:</b>						
2024	\$ 229	\$ 134	\$ 89	\$ 1	\$ —	\$ 453
2023	264	134	161	2	—	561
<b>Total assets:</b>						
March 31, 2024	\$ 11,585	\$ 6,291	\$ 5,253	\$ 4,718	\$ (312)	\$ 27,535
December 31, 2023	11,194	5,966	5,157	4,627	(41)	26,903

- (a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
- (b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in Taxes other than income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Supplemental Financial Information for additional information on total utility taxes.
- (c) Includes intersegment revenues with ComEd, PECO, and BGE, which are eliminated at Exelon.

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(a)

(b)

(c)

(d)

(e)

(e)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 4 — Segment Information

**Electric and Gas Revenue by Customer Class (Utility Registrants):**

The following tables disaggregate the Registrants' revenues recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of electric sales and natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with the Utility Registrants, but exclude any intercompany revenues.

Revenues from contracts with customers	Three Months Ended March 31, 2024						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Electric revenues</b>							
Residential	\$ 918	\$ 520	\$ 534	\$ 775	\$ 345	\$ 256	\$ 174
Small commercial & industrial	594	126	90	158	46	62	50
Large commercial & industrial	320	57	132	340	262	29	49
Public authorities & electric railroads	17	7	7	20	11	4	5
Other <sup>(a)</sup>	227	74	93	192	64	63	67
<b>Total electric revenues<sup>(b)</sup></b>	<b>\$ 2,076</b>	<b>\$ 784</b>	<b>\$ 856</b>	<b>\$ 1,485</b>	<b>\$ 728</b>	<b>\$ 414</b>	<b>\$ 345</b>
<b>Natural gas revenues</b>							
Residential	\$ —	\$ 193	\$ 271	\$ 46	\$ —	\$ 46	\$ —
Small commercial & industrial	—	64	47	17	—	17	—
Large commercial & industrial	—	—	72	2	—	2	—
Transportation	—	8	—	5	—	5	—
Other <sup>(c)</sup>	—	7	5	2	—	2	—
<b>Total natural gas revenues<sup>(d)</sup></b>	<b>\$ —</b>	<b>\$ 272</b>	<b>\$ 395</b>	<b>\$ 72</b>	<b>\$ —</b>	<b>\$ 72</b>	<b>\$ —</b>
<b>Total revenues from contracts with customers</b>	<b>\$ 2,076</b>	<b>\$ 1,056</b>	<b>\$ 1,251</b>	<b>\$ 1,557</b>	<b>\$ 728</b>	<b>\$ 486</b>	<b>\$ 345</b>
<b>Other revenues</b>							
Revenues from alternative revenue programs	\$ 19	\$ (2)	\$ 43	\$ 46	\$ 29	\$ 4	\$ 13
Other electric revenues <sup>(e)</sup>	—	—	2	3	2	1	—
Other natural gas revenues <sup>(e)</sup>	—	—	1	—	—	—	—
<b>Total other revenues</b>	<b>\$ 19</b>	<b>\$ (2)</b>	<b>\$ 46</b>	<b>\$ 49</b>	<b>\$ 31</b>	<b>\$ 5</b>	<b>\$ 13</b>
<b>Total revenues for reportable segments</b>	<b>\$ 2,095</b>	<b>\$ 1,054</b>	<b>\$ 1,297</b>	<b>\$ 1,606</b>	<b>\$ 759</b>	<b>\$ 491</b>	<b>\$ 358</b>

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 4 — Segment Information

Revenues from contracts with customers	Three Months Ended March 31, 2023						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Electric revenues</b>							
Residential	\$ 836	\$ 519	\$ 434	\$ 639	\$ 283	\$ 210	\$ 146
Small commercial & industrial	361	135	92	160	39	62	59
Large commercial & industrial	84	65	149	378	282	33	63
Public authorities & electric railroads	10	8	7	17	8	4	5
Other <sup>(a)</sup>	217	68	96	176	56	58	63
<b>Total electric revenues<sup>(b)</sup></b>	<b>\$ 1,508</b>	<b>\$ 795</b>	<b>\$ 778</b>	<b>\$ 1,370</b>	<b>\$ 668</b>	<b>\$ 367</b>	<b>\$ 336</b>
<b>Natural gas revenues</b>							
Residential	\$ —	\$ 223	\$ 278	\$ 60	\$ —	\$ 60	\$ —
Small commercial & industrial	—	75	41	26	—	26	—
Large commercial & industrial	—	1	70	1	—	1	—
Transportation	—	8	—	4	—	4	—
Other <sup>(c)</sup>	—	9	19	6	—	6	—
<b>Total natural gas revenues<sup>(d)</sup></b>	<b>\$ —</b>	<b>\$ 316</b>	<b>\$ 408</b>	<b>\$ 97</b>	<b>\$ —</b>	<b>\$ 97</b>	<b>\$ —</b>
<b>Total revenues from contracts with customers</b>	<b>\$ 1,508</b>	<b>\$ 1,111</b>	<b>\$ 1,186</b>	<b>\$ 1,467</b>	<b>\$ 668</b>	<b>\$ 464</b>	<b>\$ 336</b>
<b>Other revenues</b>							
Revenues from alternative revenue programs	\$ 153	\$ (4)	\$ 65	\$ 65	\$ 39	\$ 9	\$ 17
Other electric revenues <sup>(e)</sup>	6	4	4	4	3	1	—
Other natural gas revenues <sup>(e)</sup>	—	1	2	—	—	—	—
<b>Total other revenues</b>	<b>\$ 159</b>	<b>\$ 1</b>	<b>\$ 71</b>	<b>\$ 69</b>	<b>\$ 42</b>	<b>\$ 10</b>	<b>\$ 17</b>
<b>Total revenues for reportable segments</b>	<b>\$ 1,667</b>	<b>\$ 1,112</b>	<b>\$ 1,257</b>	<b>\$ 1,536</b>	<b>\$ 710</b>	<b>\$ 474</b>	<b>\$ 353</b>

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.

(b) Includes operating revenues from affiliates in 2024 and 2023 respectively of:

- \$2 million, \$3 million at ComEd
- \$2 million, \$1 million at PECO
- \$1 million, \$2 million at BGE
- \$3 million, \$3 million at PHI
- \$2 million, \$1 million at Pepco
- \$2 million, \$2 million at DPL
- \$1 million, \$1 million at ACE

(c) Includes revenues from off-system natural gas sales.

(d) Includes operating revenues from affiliates in 2024 and 2023 respectively of:

- less than \$1 million, \$1 million at PECO
- \$1 million, \$1 million at BGE

(e) Includes late payment charge revenues.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 5 — Accounts Receivable

**5. Accounts Receivable (All Registrants)**

**Allowance for Credit Losses on Accounts Receivable**

The following tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Three Months Ended March 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2023	\$ 317	\$ 69	\$ 95	\$ 46	\$ 107	\$ 52	\$ 19	\$ 36
Plus: Current period provision for expected credit losses <sup>(a)(b)(c)</sup>	79	22	23	15	19	12	3	4
Less: Write-offs <sup>(d)</sup> , net of recoveries <sup>(e)</sup>	50	9	11	9	21	12	5	4
Balance at March 31, 2024	\$ 346	\$ 82	\$ 107	\$ 52	\$ 105	\$ 52	\$ 17	\$ 36

	Three Months Ended March 31, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2022	\$ 327	\$ 59	\$ 105	\$ 54	\$ 109	\$ 47	\$ 21	\$ 41
Plus: Current period provision for expected credit losses	108	22	39	30	17	9	7	1
Less: Write-offs, net of recoveries	46	7	14	11	14	7	2	5
Balance at March 31, 2023	\$ 389	\$ 74	\$ 130	\$ 73	\$ 112	\$ 49	\$ 26	\$ 37

(a) For PECO, the change in current period provision for expected credit losses is primarily a result of decreased receivable balances.

(b) For BGE and DPL, the change in the current period provision for expected credit losses is primarily a result of changes in customer risk profile.

(c) For ACE, the change in current period provision for expected credit losses is primarily a result of increased receivable balances.

(d) For Pepco and DPL, the change in write-offs is primarily attributable to unfavorable customer payment behavior.

(e) Recoveries were not material to the Registrants.

The following tables present the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	Three Months Ended March 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2023	\$ 82	\$ 17	\$ 8	\$ 7	\$ 50	\$ 28	\$ 8	\$ 14
Plus: Current period provision for expected credit losses	18	3	5	2	8	7	—	1
Less: Write-offs, net of recoveries <sup>(a)</sup>	4	1	—	2	1	—	—	1
Balance at March 31, 2024	\$ 96	\$ 19	\$ 13	\$ 7	\$ 57	\$ 35	\$ 8	\$ 14

	Three Months Ended March 31, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2022	\$ 82	\$ 17	\$ 9	\$ 10	\$ 46	\$ 25	\$ 7	\$ 14
Plus: Current period provision for expected credit losses	14	2	3	4	5	3	1	1
Less: Write-offs, net of recoveries	5	1	1	2	1	—	—	1
Balance at March 31, 2023	\$ 91	\$ 18	\$ 11	\$ 12	\$ 50	\$ 28	\$ 8	\$ 14

(a) Recoveries were not material to the Registrants.



(a)

64

(b)

(c)

(b)

(a)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 5 — Accounts Receivable

**Unbilled Customer Revenue**

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets at March 31, 2024 and December 31, 2023.

	Unbilled customer revenues <sup>(a)</sup>							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2024	\$ 849	\$ 344	\$ 138	\$ 171	\$ 196	\$ 96	\$ 53	\$ 47
December 31, 2023	991	351	185	208	247	109	64	74

(a) Unbilled customer revenues are classified in Customer accounts receivable, net in the Registrants' Consolidated Balance Sheets.

**Other Purchases of Customer and Other Accounts Receivables**

The Utility Registrants are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, Delaware, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in the utilities' consolidated billing. The following table presents the total receivables purchased.

	Total receivables purchased							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three months ended March 31, 2024	\$ 1,060	\$ 235	\$ 297	\$ 219	\$ 309	\$ 194	\$ 60	\$ 55
Three months ended March 31, 2023	1,108	240	309	245	314	210	56	48

(a)

(b)

(c)

(b)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 6 — Income Taxes

**6. Income Taxes (All Registrants)**

**Rate Reconciliation**

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

	Three Months Ended March 31, 2024 <sup>(a)</sup>							
	Exelon	ComEd <sup>(b)</sup>	PECO <sup>(c)</sup>	BGE <sup>(b)</sup>	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	6.4	7.8	(0.6)	6.3	6.4	6.2	6.2	7.1
Plant basis differences	(3.8)	(0.9)	(12.2)	(1.2)	(0.9)	(1.3)	(1.1)	0.1
Excess deferred tax amortization	(14.7)	(18.9)	(2.3)	(17.5)	(6.8)	(9.9)	(5.4)	(1.3)
Amortization of investment tax credit, including deferred taxes on basis difference	(0.1)	(0.1)	—	—	(0.1)	—	(0.1)	(0.1)
Tax credits	(0.4)	(0.3)	—	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)
Other	0.3	0.4	0.4	0.1	(0.1)	—	0.2	1.0
Effective income tax rate	<u>8.7 %</u>	<u>9.0 %</u>	<u>6.3 %</u>	<u>8.3 %</u>	<u>19.2 %</u>	<u>15.7 %</u>	<u>20.5 %</u>	<u>27.5 %</u>

	Three Months Ended March 31, 2023 <sup>(a)</sup>							
	Exelon	ComEd	PECO <sup>(c)</sup>	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	6.0	7.9	(1.4)	6.4	6.0	5.4	6.3	6.9
Plant basis differences	(4.0)	(0.3)	(15.2)	(0.7)	(1.8)	(2.5)	(1.0)	(0.9)
Excess deferred tax amortization	(6.3)	(5.7)	(2.4)	(5.4)	(7.0)	(8.4)	(8.8)	(2.0)
Amortization of investment tax credit, including deferred taxes on basis difference	(0.1)	(0.1)	—	(0.1)	(0.1)	—	(0.1)	(0.1)
Tax credits	(0.5)	(0.3)	—	(0.5)	(0.4)	(0.4)	(0.4)	(0.3)
Other	0.6	0.3	0.4	(0.1)	0.3	0.5	(0.3)	0.4
Effective income tax rate	<u>16.7 %</u>	<u>22.8 %</u>	<u>2.4 %</u>	<u>20.6 %</u>	<u>18.0 %</u>	<u>15.6 %</u>	<u>16.7 %</u>	<u>25.0 %</u>

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.

(b) For ComEd, the lower effective tax rate is primarily due to CEJA which resulted in the acceleration of certain income tax benefits. For BGE, the lower effective tax rate is primarily due to the Maryland multi-year plan which resulted in the acceleration of certain income tax benefits.

(c) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 6 — Income Taxes

**Unrecognized Tax Benefits**

Exelon, PHI and ACE have the following unrecognized tax benefits at March 31, 2024 and December 31, 2023. ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

	Exelon <sup>(a)</sup>	PHI	ACE
March 31, 2024	\$ 95	\$ 51	\$ 15
December 31, 2023	94	51	15

(a) At March 31, 2024 and December 31, 2023, Exelon's unrecognized tax benefits is inclusive of \$31 million related to Constellation's share of unrecognized tax benefits for periods prior to the separation. Exelon reflected an offsetting receivable of \$31 million in Other deferred debits and other assets in the Consolidated Balance Sheet for these amounts.

**Other Tax Matters**

***Tax Matters Agreement (Exelon)***

In connection with the separation, Exelon entered into a TMA with Constellation. The TMA governs the respective rights, responsibilities, and obligations between Exelon and Constellation after the separation with respect to tax liabilities, refunds and attributes for open tax years that Constellation was part of Exelon's consolidated group for U.S. federal, state, and local tax purposes.

*Indemnification for Taxes.* As a former subsidiary of Exelon, Constellation has joint and several liability with Exelon to the IRS and certain state jurisdictions relating to the taxable periods prior to the separation. The TMA specifies that Constellation is liable for their share of taxes required to be paid by Exelon with respect to taxable periods prior to the separation to the extent Constellation would have been responsible for such taxes under the existing Exelon tax sharing agreement.

*Tax Refunds.* The TMA specifies that Constellation is entitled to their share of any future tax refunds claimed by Exelon with respect to taxable periods prior to the separation to the extent that Constellation would have received such tax refunds under the existing Exelon tax sharing agreement.

*Tax Attributes.* At the date of separation certain tax attributes, primarily pre-closing tax credit carryforwards, that were generated by Constellation were required by law to be allocated to Exelon. The TMA provides that Exelon will reimburse Constellation when those allocated tax credit carryforwards are utilized. As of March 31, 2024, Exelon recorded a payable of \$183 million and \$331 million in Other current liabilities and Other deferred credits and other liabilities, respectively, in the Consolidated Balance Sheet for tax attribute carryforwards that are expected to be utilized and reimbursed to Constellation.

***Corporate Alternative Minimum Tax (All Registrants)***

On August 16, 2022, the IRA was signed into law and implements a new corporate alternative minimum tax (CAMT) that imposes a 15.0% tax on modified GAAP net income. Corporations are entitled to a tax credit (minimum tax credit) to the extent the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT.

Beginning in 2023, based on the existing statute, Exelon and each of the Utility Registrants will be subject to and will report the CAMT on a separate Registrant basis in the Consolidated Statements of Operations and Comprehensive Income and the Consolidated Balance Sheets. The deferred tax asset related to the minimum tax credit carryforward will be realized to the extent Exelon's consolidated deferred tax liabilities exceed the minimum tax credit carryforward. Exelon's deferred tax liabilities are expected to exceed the minimum tax credit carryforward for the foreseeable future and thus no valuation allowance is required. Exelon is continuing to assess the financial statement impacts of the IRA and will update estimates based on future guidance issued by the U.S. Treasury.

**7. Retirement Benefits (All Registrants)**

**Defined Benefit Pension and OPEB**



**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 7 — Retirement Benefits

The majority of the 2024 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 5.19%. The majority of the 2024 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.50% for funded plans and a discount rate of 5.17%.

During the first quarter of 2024, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2024. This valuation resulted in an increase to the pension obligation of \$98 million and a decrease to the OPEB obligation of \$1 million. Additionally, AOCI increased by \$25 million (after-tax) and regulatory assets and liabilities increased by \$66 million and \$2 million, respectively.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three months ended March 31, 2024 and 2023.

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2024	2023	2024	2023
<b>Components of net periodic benefit cost</b>				
Service cost	\$ 42	\$ 39	\$ 7	\$ 6
Interest cost	141	145	24	25
Expected return on assets	(184)	(189)	(21)	(21)
Amortization of:				
Prior service cost (credit)	1	1	(2)	(2)
Actuarial loss	53	41	—	—
<b>Net periodic benefit cost</b>	<b>\$ 53</b>	<b>\$ 37</b>	<b>\$ 8</b>	<b>\$ 8</b>

The amounts below represent the Registrants' allocated pension and OPEB costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant, and equipment, net while the non-service cost components are included in Other, net and Regulatory assets. For the Utility Registrants, which apply multi-employer accounting, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant, and equipment, net in their consolidated financial statements.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 7 — Retirement Benefits

Pension and OPEB Costs (Benefit)	Three Months Ended March 31,	
	2024	2023
Exelon	\$ 61	\$ 45
ComEd	17	6
PECO	—	(3)
BGE	15	14
PHI	23	24
Pepco	9	8
DPL	4	4
ACE	3	4

**Defined Contribution Savings Plan**

The Registrants participate in a 401(k) defined contribution savings plan that is sponsored by Exelon. The plan is qualified under applicable sections of the IRC and allows employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the employer contributions and employer matching contributions to the savings plan for the three months ended March 31, 2024 and 2023.

Savings Plan Employer Contributions	Three Months Ended March 31,	
	2024	2023
Exelon	\$ 22	\$ 21
ComEd	10	9
PECO	3	3
BGE	3	2
PHI	2	3
Pepco	1	1
DPL	1	1
ACE	—	—

**8. Derivative Financial Instruments (All Registrants)**

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations. The Registrants do not execute derivatives for speculative or proprietary trading purposes.

Authoritative 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 immediately. 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 NPNS, cash flow hedges, and fair value hedges. At ComEd, derivative economic hedges related to commodities are recorded at fair value and offset by a corresponding regulatory asset or liability. At Exelon, derivative economic hedges related to interest rates are recorded at fair value and offsets are recorded to Electric operating revenues or Interest expense based on the activity the transaction is economically hedging. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed. At Exelon, derivative hedges that qualify and are designated as cash flow hedges are recorded at fair value and offsets are recorded to AOCI.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade. Cash collateral held by PECO, BGE, Pepco, DPL, and ACE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meets certain qualifications.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 8 — Derivative Financial Instruments

**Commodity Price Risk**

The Utility Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, which are either determined to be non-derivative or classified as economic hedges. The Utility Registrants procure electric and natural gas supply through a competitive procurement process approved by each of the respective state utility commissions. The Utility Registrants' hedging programs are intended to reduce exposure to energy and natural gas price volatility and have no direct earnings impact as the costs are fully recovered from customers through regulatory-approved recovery mechanisms. The following table provides a summary of the Utility Registrants' primary derivative hedging instruments, listed by commodity and accounting treatment.

Registrant	Commodity	Accounting Treatment	Hedging Instrument
ComEd	Electricity	NPNS	Fixed price contracts based on all requirements in the IPA procurement plans.
	Electricity	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability <sup>(a)</sup>	20-year floating-to-fixed energy swap contracts beginning June 2012 based on the renewable energy resource procurement requirements in the Illinois Settlement Legislation of approximately 1.3 million MWhs per year.
PECO	Electricity	NPNS	Fixed price contracts for default supply requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts to cover about 10% of planned natural gas purchases in support of projected firm sales.
BGE	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts for between 10-20% of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period.
Pepco	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
DPL	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed and index priced contracts through full requirements contracts.
	Gas	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability <sup>(b)</sup>	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

(a) See Note 3 — Regulatory Matters of the 2023 Form 10-K for additional information.

(b) The fair value of the DPL economic hedge is not material at March 31, 2024 and December 31, 2023.

The fair value of derivative economic hedges is presented in Other current assets and current and noncurrent Mark-to-market derivative liabilities in Exelon's and ComEd's Consolidated Balance Sheets.

**Interest Rate and Other Risk (Exelon)**

Exelon Corporate uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon Corporate may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. In addition, Exelon Corporate utilized interest rate swaps to manage interest rate exposure and manage potential fluctuations in Electric operating revenues at the corporate level in consolidation. These interest rate swaps are accounted for as economic hedges. A hypothetical 50 basis point change in the interest rates associated with Exelon's interest rate swaps as of March 31, 2024 would result in an immaterial impact to Exelon's Consolidated Net Income.



**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 8 — Derivative Financial Instruments

Below is a summary of the interest rate hedge balances at March 31, 2024 and December 31, 2023.

	March 31, 2024		
	Derivatives Designated as Hedging Instruments	Economic Hedges	Total
Other deferred debits (noncurrent assets)	\$ 2	\$ —	\$ 2
Total derivative assets	2	—	2
Mark-to-market derivative liabilities (noncurrent liabilities)	(1)	—	(1)
Total mark-to-market derivative liabilities	(1)	—	(1)
Total mark-to-market derivative net assets	\$ 1	\$ —	\$ 1

	December 31, 2023		
	Derivatives Designated as Hedging Instruments	Economic Hedges	Total
Other current assets	\$ 11	\$ 1	\$ 12
Total derivative assets	11	1	12
Mark-to-market derivative liabilities (current liabilities)	(24)	(22)	(46)
Total mark-to-market derivative liabilities	(24)	(22)	(46)
Total mark-to-market derivative net assets	\$ (13)	\$ (21)	\$ (34)

**Cash Flow Hedges (Interest Rate Risk)**

For derivative instruments that qualify and are designated as cash flow hedges, the changes in fair value each period are initially recorded in AOCI and reclassified into earnings when the underlying transaction affects earnings.

In February 2024, Exelon terminated the previously issued floating-to-fixed swaps with a total notional of \$1.3 billion upon issuance of \$1.7 billion of debt. See Note 9 – Debt and Credit Agreements for additional information on the debt issuance. Prior to the termination, the 2024 year-to-date AOCI derivative gain was \$33 million (net of tax). The settlements resulted in a cash receipt of \$30 million. The accumulated AOCI gain of \$23 million (net of tax) is being amortized into Interest expense in Exelon's Consolidated Statement of Operations and Comprehensive Income over the 5-year and 10-year terms of the swaps. During the first quarter of 2024, Exelon Corporate entered into \$145 million notional of 5-year maturity floating-to-fixed swaps and \$145 million notional of 10-year maturity floating-to-fixed swaps, for a total notional of \$290 million designated as cash flow hedges. The following table provides the notional amounts outstanding held by Exelon at March 31, 2024 and December 31, 2023.

	March 31, 2024	December 31, 2023
5-year maturity floating-to-fixed swaps	\$ 145	\$ 655
10-year maturity floating-to-fixed swaps	145	655
Total	\$ 290	\$ 1,310

The related AOCI derivative gains for the three months ended March 31, 2024 and 2023 were immaterial, respectively. See Note 13 – Changes in Accumulated Other Comprehensive Income (Loss) for additional information.

**Economic Hedges (Interest Rate and Other Risk)**

Exelon Corporate executes derivative instruments to mitigate exposure to fluctuations in interest rates but for which the fair value or cash flow hedge elections were not made. For derivatives intended to serve as economic hedges, fair value is recorded on the balance sheet and changes in fair value each period are recognized in earnings or as a regulatory asset or liability, if regulatory requirements are met, each period.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 8 — Derivative Financial Instruments

Exelon Corporate entered into floating-to-fixed interest rate cap swaps to manage a portion of interest rate exposure in connection with existing borrowings. As of December 31, 2023, Exelon held \$1,000 million notional of floating-to-fixed interest rate cap swaps, which matured in March 2024. Exelon received payments on the interest rate cap when the floating rate exceeded the fixed rate. Settlements received are immaterial as of March 31, 2024.

Additionally, to manage potential fluctuations in Electric operating revenues related to ComEd's distribution formula rate, Exelon Corporate entered into a total \$4,875 million of notional of 30-year constant maturity treasury interest rate (Corporate 30-year treasury) swaps from 2022 through 2023. The Corporate 30-year treasury swaps matured on December 31, 2023 and Exelon recorded a Mark-to-market liability of \$22 million for the final settlement amount, which was paid in January 2024.

Exelon Corporate recognized the following net pre-tax mark-to-market (losses) which are also recognized in Net fair value changes related to derivatives in Exelon's Consolidated Statements of Cash Flows.

Income Statement Location	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	Gain (Loss)	Gain (Loss)
Electric operating revenues	\$ —	\$ 1
Interest expense	—	(1)
<b>Total</b>	<b>\$ —</b>	<b>\$ —</b>

**Credit Risk**

The Registrants 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. The Utility Registrants have contracts to procure electric and natural gas supply that provide suppliers with a certain amount of unsecured credit. If the exposure on the supply contract exceeds the amount of unsecured credit, the suppliers may be required to post collateral. The net credit exposure is mitigated primarily by the ability to recover procurement costs through customer rates. The amount of cash collateral received from external counterparties remained relatively consistent as of March 31, 2024 due to stable energy prices. The following table reflects the Registrants' cash collateral held from external counterparties, which is recorded in Other current liabilities on their respective Consolidated Balance Sheets, as of March 31, 2024 and December 31, 2023:

	March 31, 2024	December 31, 2023
Exelon	\$ 156	\$ 148
ComEd	154	146
PECO <sup>(a)</sup>	—	—
BGE	1	1
PHI	1	1
Pepco <sup>(b)</sup>	—	1
DPL	1	—
ACE	1	—

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 8 — Derivative Financial Instruments

- (a) PECO had less than one million in cash collateral held with external parties at March 31, 2024 and December 31, 2023.  
(b) Pepco had less than one million in cash collateral held with external parties at March 31, 2024.

The Utility Registrants' electric supply procurement contracts do not contain provisions that would require them to post collateral. PECO's, BGE's, and DPL's natural gas procurement contracts contain provisions that could require PECO, BGE, and DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty, with thresholds contingent upon PECO's, BGE's, and DPL's credit rating. As of March 31, 2024, PECO, BGE, and DPL were not required to post collateral for any of these agreements. If PECO, BGE, or DPL lost their investment grade credit rating as of March 31, 2024, they could have been required to post collateral to their counterparties of \$27 million, \$47 million, and \$12 million, respectively.

**9. Debt and Credit Agreements (All Registrants)**

**Short-Term Borrowings**

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and borrowings from the Exelon intercompany money pool. The Registrants may use their respective 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 the Registrants' commercial paper programs supported by the revolving credit agreements at March 31, 2024 and December 31, 2023.

Commercial Paper Issuer	Outstanding Commercial Paper at		Average Interest Rate on Commercial Paper Borrowings at	
	March 31, 2024	December 31, 2023	March 31, 2024	December 31, 2023
Exelon <sup>(a)</sup>	\$ 1,307	\$ 1,624	5.53 %	5.58 %
ComEd	\$ 330	\$ 202	5.43 %	5.53 %
PECO	\$ —	\$ 165	— %	5.57 %
BGE	\$ 406	\$ 336	5.57 %	5.59 %
PHI <sup>(b)</sup>	\$ —	\$ 394	— %	5.60 %
Pepco	\$ —	\$ 132	— %	5.59 %
DPL	\$ —	\$ 63	— %	5.60 %
ACE	\$ —	\$ 199	— %	5.60 %

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 9 — Debt and Credit Agreements

- (a) Exelon Corporate had \$571 million and \$527 million in outstanding commercial paper borrowings at March 31, 2024 and December 31, 2023, respectively.
- (b) Represents the consolidated amounts of Pepco, DPL, and ACE.

**Revolving Credit Agreements**

Exelon Corporate and the Utility Registrants each have a 5-year revolving credit facility. The following table reflects the credit agreements:

Borrower	Aggregate Bank Commitment	Interest Rate
Exelon Corporate	\$ 900	SOFR plus 1.275 %
ComEd	\$ 1,000	SOFR plus 1.000 %
PECO	\$ 600	SOFR plus 0.900 %
BGE	\$ 600	SOFR plus 0.900 %
Pepco	\$ 300	SOFR plus 1.075 %
DPL	\$ 300	SOFR plus 1.000 %
ACE	\$ 300	SOFR plus 1.000 %

Exelon Corporate and the Utility Registrants had no outstanding amounts on the revolving credit facilities as of March 31, 2024.

The Utility Registrants have credit facility agreements, arranged at minority and community banks, which are solely utilized to issue letters of credit. The facility agreements have aggregate commitments of \$40 million, \$40 million, \$15 million, \$15 million, \$15 million, and \$15 million, at ComEd, PECO, BGE, Pepco, DPL, and ACE, respectively. These facilities expire on October 4, 2024.

See Note 16 — Debt and Credit Agreements of the 2023 Form 10-K for additional information on the Registrants' credit facilities.

**Short-Term Loan Agreements**

On March 23, 2017, Exelon Corporate entered into a term loan agreement for \$500 million. The loan agreement was renewed in the first quarter of 2024 and was bifurcated into two tranches of \$350 million and \$150 million on March 14, 2024. The agreements will expire on March 14, 2025. Pursuant to the loan agreements, loans made thereunder bear interest at a variable rate equal to SOFR plus 1.05% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On May 9, 2023, ComEd entered into a 364-day term loan agreement for \$400 million with a variable rate equal to SOFR plus 1.00% and an expiration date of May 7, 2024. On May 1, 2024, ComEd entered into an agreement to extend the \$400 million term loan through the expiration date of June 28, 2024. Interest on the extended loan will be based on a variable rate equal to SOFR plus 1.00%. The original proceeds from the loan were used to repay outstanding commercial paper obligations and for general corporate purposes. The loan agreement is reflected in Exelon's and ComEd's Consolidated Balance Sheets within Short-term borrowings.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 9 — Debt and Credit Agreements

**Long-Term Debt**

***Issuance of Long-Term Debt***

During the three months ended March 31, 2024, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Notes	5.15%	March 15, 2029	\$650	Repay Exelon SMBC Term Loan, outstanding commercial paper, and for general corporate purposes.
Exelon	Notes	5.45%	March 15, 2034	\$650	Repay Exelon SMBC Term Loan, outstanding commercial paper, and for general corporate purposes.
Exelon	Notes	5.60%	March 15, 2053	\$400	Repay Exelon SMBC Term Loan, outstanding commercial paper, and for general corporate purposes.
Pepco	First Mortgage Bonds	5.20%	March 15, 2034	\$375	Refinance existing indebtedness, refinance outstanding commercial paper obligations, and for general corporate purposes.
Pepco	First Mortgage Bonds	5.50%	March 15, 2054	\$300	Refinance existing indebtedness, refinance outstanding commercial paper obligations, and for general corporate purposes.
DPL	First Mortgage Bonds	5.24%	March 20, 2034	\$100	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.55%	March 20, 2054	\$75	Repay existing indebtedness and for general corporate purposes.
ACE <sup>(a)</sup>	First Mortgage Bonds	5.55%	March 20, 2054	\$75	Repay existing indebtedness and for general corporate purposes.

(a) On March 20, 2024, ACE entered into a purchase agreement of First Mortgage Bonds of \$75 million and \$100 million at 5.29% and 5.49% due on August 28, 2034 and August 28, 2039, respectively. The closing date of the issuance is expected to occur in August 2024.

**Debt Covenants**

As of March 31, 2024, the Registrants are in compliance with debt covenants.

**10. Fair Value of Financial Assets and Liabilities (All Registrants)**

Exelon measures and classifies fair value measurements in accordance with the hierarchy as defined by GAAP. 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 the Registrants have the ability to 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.

Exelon's valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 17 — Fair Value of Financial Assets and Liabilities of the 2023 Form 10-K.

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(a)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 10 — Fair Value of Financial Assets and Liabilities

**Fair Value of Financial Liabilities Recorded at Amortized Cost**

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of March 31, 2024 and December 31, 2023. The Registrants have no financial liabilities measured using the NAV practical expedient.

The carrying amounts of the Registrants' short-term liabilities as presented in their Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	March 31, 2024					December 31, 2023				
	Carrying Amount	Fair Value			Total	Carrying Amount	Fair Value			Total
		Level 1	Level 2	Level 3			Level 1	Level 2	Level 3	
<b>Long-Term Debt, including amounts due within one year<sup>(a)</sup></b>										
Exelon	\$ 42,774	\$ —	\$ 34,426	\$ 3,613	\$ 38,039	\$ 41,095	\$ —	\$ 33,804	\$ 3,442	\$ 37,246
ComEd	11,487	—	9,910	—	9,910	11,486	—	10,210	—	10,210
PECO	5,134	—	4,391	—	4,391	5,134	—	4,562	—	4,562
BGE	4,602	—	4,015	—	4,015	4,602	—	4,145	—	4,145
PHI	9,153	—	4,356	3,613	7,969	8,648	—	4,160	3,442	7,602
Pepco	4,359	—	2,549	1,570	4,119	4,096	—	2,311	1,600	3,911
DPL	2,254	—	668	1,274	1,942	2,080	—	694	1,134	1,828
ACE	1,909	—	929	768	1,697	1,833	—	939	708	1,647
<b>Long-Term Debt to Financing Trusts</b>										
Exelon	\$ 390	\$ —	\$ —	\$ 392	\$ 392	\$ 390	\$ —	\$ —	\$ 390	\$ 390
ComEd	205	—	—	209	209	205	—	—	208	208
PECO	184	—	—	183	183	184	—	—	182	182

(a) Includes unamortized debt issuance costs, unamortized debt discount and premium, net, purchase accounting fair value adjustments, and finance lease liabilities which are not fair valued. Refer to Note 16 — Debt and Credit Agreements of the 2023 Form 10-K for unamortized debt issuance costs, unamortized debt discount and premium, net, and purchase accounting fair value adjustments and Note 10 — Leases of the 2023 Form 10-K for finance lease liabilities.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 10 — Fair Value of Financial Assets and Liabilities

**Recurring Fair Value Measurements**

The following tables present assets and liabilities measured and recorded at fair value in the Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at March 31, 2024 and December 31, 2023. Exelon and the Utility Registrants have immaterial and no financial assets or liabilities measured using the NAV practical expedient, respectively:

**Exelon**

	At March 31, 2024				At December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>								
Cash equivalents <sup>(a)</sup>	\$ 883	\$ —	\$ —	\$ 883	\$ 618	\$ —	\$ —	\$ 618
Rabbi trust investments								
Cash equivalents	68	—	—	68	67	—	—	67
Mutual funds	57	—	—	57	53	—	—	53
Fixed income	—	7	—	7	—	7	—	7
Life insurance contracts	—	65	43	108	—	61	43	104
Rabbi trust investments subtotal	125	72	43	240	120	68	43	231
Interest rate derivative assets								
Derivatives designated as hedging instruments	—	2	—	2	—	11	—	11
Economic hedges	—	—	—	—	—	1	—	1
Interest rate derivative assets subtotal	—	2	—	2	—	12	—	12
<b>Total assets</b>	<b>1,008</b>	<b>74</b>	<b>43</b>	<b>1,125</b>	<b>738</b>	<b>80</b>	<b>43</b>	<b>861</b>
<b>Liabilities</b>								
Commodity derivative liabilities	—	—	(108)	(108)	—	—	(133)	(133)
Interest rate derivative liabilities								
Derivatives designated as hedging instruments	—	(1)	—	(1)	—	(24)	—	(24)
Economic hedges	—	—	—	—	—	(22)	—	(22)
Interest rate derivative liabilities subtotal	—	(1)	—	(1)	—	(46)	—	(46)
Deferred compensation obligation	—	(75)	—	(75)	—	(75)	—	(75)
<b>Total liabilities</b>	<b>—</b>	<b>(76)</b>	<b>(108)</b>	<b>(184)</b>	<b>—</b>	<b>(121)</b>	<b>(133)</b>	<b>(254)</b>
<b>Total net assets (liabilities)</b>	<b>\$ 1,008</b>	<b>\$ (2)</b>	<b>\$ (65)</b>	<b>\$ 941</b>	<b>\$ 738</b>	<b>\$ (41)</b>	<b>\$ (90)</b>	<b>\$ 607</b>

(a) Exelon excludes cash of \$271 million and \$334 million at March 31, 2024 and December 31, 2023, respectively, and restricted cash of \$154 million and \$149 million at March 31, 2024 and December 31, 2023, respectively, and includes long-term restricted cash of \$99 million and \$174 million at March 31, 2024 and December 31, 2023, respectively, which is reported in Other deferred debits and other assets in the Consolidated Balance Sheets.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 10 — Fair Value of Financial Assets and Liabilities

**ComEd, PECO, and BGE**

At March 31, 2024	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents <sup>(a)</sup>	\$ 398	\$ —	\$ —	\$ 398	\$ 14	\$ —	\$ —	\$ 14	\$ —	\$ —	\$ —	\$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	10	—	—	10	10	—	—	10
Life insurance contracts	—	—	—	—	—	19	—	19	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	10	19	—	29	10	—	—	10
<b>Total assets</b>	<b>398</b>	<b>—</b>	<b>—</b>	<b>398</b>	<b>24</b>	<b>19</b>	<b>—</b>	<b>43</b>	<b>10</b>	<b>—</b>	<b>—</b>	<b>10</b>
<b>Liabilities</b>												
Commodity derivative liabilities <sup>(b)</sup>	—	—	(108)	(108)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(9)	—	(9)	—	(9)	—	(9)	—	(4)	—	(4)
<b>Total liabilities</b>	<b>—</b>	<b>(9)</b>	<b>(108)</b>	<b>(117)</b>	<b>—</b>	<b>(9)</b>	<b>—</b>	<b>(9)</b>	<b>—</b>	<b>(4)</b>	<b>—</b>	<b>(4)</b>
<b>Total net assets (liabilities)</b>	<b>\$ 398</b>	<b>\$ (9)</b>	<b>\$ (108)</b>	<b>\$ 281</b>	<b>\$ 24</b>	<b>\$ 10</b>	<b>\$ —</b>	<b>\$ 34</b>	<b>\$ 10</b>	<b>\$ (4)</b>	<b>\$ —</b>	<b>\$ 6</b>

At December 31, 2023	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents <sup>(a)</sup>	\$ 453	\$ —	\$ —	\$ 453	\$ 9	\$ —	\$ —	\$ 9	\$ —	\$ —	\$ —	\$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	9	—	—	9
Life insurance contracts	—	—	—	—	—	18	—	18	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	18	—	27	9	—	—	9
<b>Total assets</b>	<b>453</b>	<b>—</b>	<b>—</b>	<b>453</b>	<b>18</b>	<b>18</b>	<b>—</b>	<b>36</b>	<b>9</b>	<b>—</b>	<b>—</b>	<b>9</b>
<b>Liabilities</b>												
Commodity derivative liabilities <sup>(b)</sup>	—	—	(133)	(133)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(8)	—	(8)	—	(4)	—	(4)
<b>Total liabilities</b>	<b>—</b>	<b>(8)</b>	<b>(133)</b>	<b>(141)</b>	<b>—</b>	<b>(8)</b>	<b>—</b>	<b>(8)</b>	<b>—</b>	<b>(4)</b>	<b>—</b>	<b>(4)</b>
<b>Total net assets (liabilities)</b>	<b>\$ 453</b>	<b>\$ (8)</b>	<b>\$ (133)</b>	<b>\$ 312</b>	<b>\$ 18</b>	<b>\$ 10</b>	<b>\$ —</b>	<b>\$ 28</b>	<b>\$ 9</b>	<b>\$ (4)</b>	<b>\$ —</b>	<b>\$ 5</b>

(a) ComEd excludes cash of \$75 million and \$86 million at March 31, 2024 and December 31, 2023, respectively, and restricted cash of \$154 million and \$147 million at March 31, 2024 and December 31, 2023, respectively. Additionally, ComEd includes long-term restricted cash of \$99 million and \$174 million at March 31, 2024 and December 31, 2023, respectively, which is reported in Other deferred debits and other assets in the Consolidated Balance Sheets. PECO excludes cash of \$34 million and \$42 million at March 31, 2024 and December 31, 2023, respectively. BGE excludes cash of \$27 million and \$47 million at March 31, 2024 and December 31, 2023, respectively, and restricted cash of zero and \$1 million at March 31, 2024 and December 31, 2023, respectively.

(b) The Level 3 balance consists of the current and noncurrent liability of \$29 million and \$79 million, respectively, at March 31, 2024 and \$27 million and \$106 million, respectively, at December 31, 2023 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 10 — Fair Value of Financial Assets and Liabilities

**PHI, Pepco, DPL, and ACE**

PHI	At March 31, 2024				At December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>								
Cash equivalents <sup>(a)</sup>	\$ 438	\$ —	\$ —	\$ 438	\$ 107	\$ —	\$ —	\$ 107
Rabbi trust investments								
Cash equivalents	65	—	—	65	64	—	—	64
Mutual funds	9	—	—	9	9	—	—	9
Fixed income	—	7	—	7	—	7	—	7
Life insurance contracts	—	22	41	63	—	21	41	62
Rabbi trust investments subtotal	74	29	41	144	73	28	41	142
<b>Total assets</b>	<b>512</b>	<b>29</b>	<b>41</b>	<b>582</b>	<b>180</b>	<b>28</b>	<b>41</b>	<b>249</b>
<b>Liabilities</b>								
Deferred compensation obligation	—	(12)	—	(12)	—	(13)	—	(13)
<b>Total liabilities</b>	<b>—</b>	<b>(12)</b>	<b>—</b>	<b>(12)</b>	<b>—</b>	<b>(13)</b>	<b>—</b>	<b>(13)</b>
<b>Total net assets</b>	<b>\$ 512</b>	<b>\$ 17</b>	<b>\$ 41</b>	<b>\$ 570</b>	<b>\$ 180</b>	<b>\$ 15</b>	<b>\$ 41</b>	<b>\$ 236</b>

At March 31, 2024	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents <sup>(a)</sup>	\$ 192	\$ —	\$ —	\$ 192	\$ 241	\$ —	\$ —	\$ 241	\$ —	\$ —	\$ —	\$ —
Rabbi trust investments												
Cash equivalents	64	—	—	64	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	41	63	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	64	22	41	127	—	—	—	—	—	—	—	—
<b>Total assets</b>	<b>256</b>	<b>22</b>	<b>41</b>	<b>319</b>	<b>241</b>	<b>—</b>	<b>—</b>	<b>241</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Liabilities</b>												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
<b>Total liabilities</b>	<b>—</b>	<b>(1)</b>	<b>—</b>	<b>(1)</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Total net assets</b>	<b>\$ 256</b>	<b>\$ 21</b>	<b>\$ 41</b>	<b>\$ 318</b>	<b>\$ 241</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 241</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ —</b>

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 10 — Fair Value of Financial Assets and Liabilities

At December 31, 2023	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents <sup>(a)</sup>	\$ 23	\$ —	\$ —	\$ 23	\$ 1	\$ —	\$ —	\$ 1	\$ —	\$ —	\$ —	\$ —
<b>Rabbi trust investments</b>												
Cash equivalents	63	—	—	63	—	—	—	—	—	—	—	—
Life insurance contracts	—	21	41	62	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	63	21	41	125	—	—	—	—	—	—	—	—
<b>Total assets</b>	<b>86</b>	<b>21</b>	<b>41</b>	<b>148</b>	<b>1</b>	<b>—</b>	<b>—</b>	<b>1</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Liabilities</b>												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
<b>Total liabilities</b>	<b>—</b>	<b>(1)</b>	<b>—</b>	<b>(1)</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Total net assets</b>	<b>\$ 86</b>	<b>\$ 20</b>	<b>\$ 41</b>	<b>\$ 147</b>	<b>\$ 1</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 1</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ —</b>

(a) PHI excludes cash of \$89 million and \$96 million at March 31, 2024 and December 31, 2023, respectively, and restricted cash of zero and \$1 million at March 31, 2024 and December 31, 2023, respectively. Pepco excludes cash of \$28 million and \$48 million at March 31, 2024 and December 31, 2023, respectively, and restricted cash of zero and \$1 million at March 31, 2024 and December 31, 2023, respectively. DPL excludes cash of \$29 million and \$15 million at March 31, 2024 and December 31, 2023, respectively. ACE excludes cash of \$27 million and \$21 million at March 31, 2024 and December 31, 2023, respectively.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 10 — Fair Value of Financial Assets and Liabilities

**Reconciliation of Level 3 Assets and Liabilities**

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2024 and 2023:

	Exelon	ComEd	PHI and Pepco
	Total	Commodity Derivatives	Life Insurance Contracts
<b>Three Months Ended March 31, 2024</b>			
Balance at December 31, 2023	\$ (90)	\$ (133)	\$ 41
Total realized / unrealized gains (losses)			
Included in net income <sup>(a)</sup>	—	—	—
Included in regulatory assets/liabilities	25	25 <sup>(b)</sup>	—
Balance at March 31, 2024	\$ (65)	\$ (108) <sup>(c)</sup>	\$ 41
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities at March 31, 2024	\$ —	\$ —	\$ —
<b>Three Months Ended March 31, 2023</b>			
Balance at December 31, 2022	\$ (44)	\$ (84)	\$ 40
Total realized / unrealized gains (losses)			
Included in net income <sup>(a)</sup>	1	—	1
Included in regulatory assets/liabilities	(14)	(14) <sup>(b)</sup>	—
Balance at March 31, 2023	\$ (57)	\$ (98)	\$ 41
The amount of total gains included in income attributed to the change in unrealized gain related to assets and liabilities at March 31, 2023	\$ 1	\$ —	\$ 1

(a) Classified in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

(b) Includes \$13 million of increases in fair value and an increase for realized gains due to settlements of \$12 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2024. Includes \$25 million of decreases in fair value and an increase for realized losses due to settlements of \$11 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2023.

(c) The balance of the current and noncurrent asset was effectively zero as of March 31, 2024. The balance consists of a current and noncurrent liability of \$29 million and \$79 million, respectively, as of March 31, 2024.

**Commodity Derivatives (Exelon and ComEd)**

The table below discloses the significant unobservable inputs to the forward curve used to value mark-to-market derivatives.

Type of trade	Fair Value at March 31, 2024	Fair Value at December 31, 2023	Valuation Technique	Unobservable Input	2024 Range & Arithmetic Average		2023 Range & Arithmetic Average					
Commodity derivatives	\$ (108)	\$ (133)	Discounted Cash Flow	Forward power price <sup>(a)</sup>	\$22.68	\$ -	\$84.62	\$46.94	\$30.27	\$ -	\$73.71	\$43.35

(a) An increase to the forward power price would increase the fair value.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

**11. Commitments and Contingencies (All Registrants)**

The following is an update to the current status of commitments and contingencies set forth in Note 18 — Commitments and Contingencies of the 2023 Form 10-K.

**Commitments**

**PHI Merger Commitments (Exelon, PHI, Pepco, DPL, and ACE).** Approval of the PHI Merger in Delaware, New Jersey, Maryland, and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments. The following amounts represent total commitment costs that have been recorded since the acquisition date and the total remaining obligations for Exelon, PHI, Pepco, DPL, and ACE at March 31, 2024:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	\$ 513	\$ 320	\$ 120	\$ 89	\$ 111
Remaining commitments <sup>(a)</sup>	35	31	28	2	1

(a) Remaining commitments extend through 2026 and include escrow funds, charitable contributions, and rate credits.

(a)  
(b)  
(c)  
(d)

(a)  
(b)  
(c)

(a)  
(b)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Commitments and Contingencies

**Commercial Commitments (All Registrants).** The Registrants' commercial commitments at March 31, 2024, representing commitments potentially triggered by future events were as follows:

	Total	Expiration within					2029 and beyond
		2024	2025	2026	2027	2028	
<b>Exelon</b>							
Letters of credit <sup>(a)</sup>	\$ 32	\$ 24	\$ 8	\$ —	\$ —	\$ —	\$ —
Surety bonds <sup>(b)</sup>	194	181	13	—	—	—	—
Financing trust guarantees <sup>(c)</sup>	378	—	—	—	—	78	300
Guaranteed lease residual values <sup>(d)</sup>	25	—	3	5	4	6	7
Total commercial commitments	<u>\$ 629</u>	<u>\$ 205</u>	<u>\$ 24</u>	<u>\$ 5</u>	<u>\$ 4</u>	<u>\$ 84</u>	<u>\$ 307</u>
<b>ComEd</b>							
Letters of credit <sup>(a)</sup>	\$ 17	\$ 14	\$ 3	\$ —	\$ —	\$ —	\$ —
Surety bonds <sup>(b)</sup>	36	34	2	—	—	—	—
Financing trust guarantees <sup>(c)</sup>	200	—	—	—	—	—	200
Total commercial commitments	<u>\$ 253</u>	<u>\$ 48</u>	<u>\$ 5</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 200</u>
<b>PECO</b>							
Letters of credit <sup>(a)</sup>	\$ 3	\$ —	\$ 3	\$ —	\$ —	\$ —	\$ —
Surety bonds <sup>(b)</sup>	2	1	1	—	—	—	—
Financing trust guarantees <sup>(c)</sup>	178	—	—	—	—	78	100
Total commercial commitments	<u>\$ 183</u>	<u>\$ 1</u>	<u>\$ 4</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 78</u>	<u>\$ 100</u>
<b>BGE</b>							
Letters of credit <sup>(a)</sup>	\$ 7	\$ 7	\$ —	\$ —	\$ —	\$ —	\$ —
Surety bonds <sup>(b)</sup>	3	2	1	—	—	—	—
Total commercial commitments	<u>\$ 10</u>	<u>\$ 9</u>	<u>\$ 1</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>
<b>PHI</b>							
Surety bonds <sup>(b)</sup>	\$ 96	\$ 91	\$ 5	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values <sup>(d)</sup>	25	—	3	5	4	6	7
Total commercial commitments	<u>\$ 121</u>	<u>\$ 91</u>	<u>\$ 8</u>	<u>\$ 5</u>	<u>\$ 4</u>	<u>\$ 6</u>	<u>\$ 7</u>
<b>Pepco</b>							
Surety bonds <sup>(a)</sup>	\$ 85	\$ 84	\$ 1	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values <sup>(d)</sup>	8	—	1	2	1	2	2
Total commercial commitments	<u>\$ 93</u>	<u>\$ 84</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 1</u>	<u>\$ 2</u>	<u>\$ 2</u>
<b>DPL</b>							
Surety bonds <sup>(b)</sup>	\$ 6	\$ 3	\$ 3	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values <sup>(d)</sup>	10	—	1	2	2	2	3
Total commercial commitments	<u>\$ 16</u>	<u>\$ 3</u>	<u>\$ 4</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 3</u>
<b>ACE</b>							
Surety bonds <sup>(b)</sup>	\$ 5	\$ 4	\$ 1	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values <sup>(d)</sup>	7	—	1	1	1	2	2
Total commercial commitments	<u>\$ 12</u>	<u>\$ 4</u>	<u>\$ 2</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 2</u>	<u>\$ 2</u>

(a) Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.



**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

- (b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds. Historically, payments under the guarantees have not been made and the likelihood of payments being required is remote.
- (c) Reflects guarantee of ComEd and PECO securities held by ComEd Financing III, PECO Trust III, and PECO Trust IV.
- (d) 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 lease term associated with these assets ranges from 1 to 9 years. The maximum potential obligation at the end of the minimum lease term would be \$57 million guaranteed by Exelon and PHI, of which \$19 million, \$22 million, and \$16 million is guaranteed by Pepco, DPL, and ACE, respectively. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

**Environmental Remediation Matters**

**General (All Registrants).** The Registrants' 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, the Registrants are 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. The Registrants own or lease 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, the Registrants are 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, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, 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 Registrants' financial statements.

**MGP Sites (All Registrants).** ComEd, PECO, BGE, and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For some sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has 16 sites that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2031.
- PECO has 6 sites that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2025.
- BGE has 4 sites that currently require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2025.
- DPL has 1 site that is currently under study and the required cost at the site is not expected to be material.

The historical nature of the MGP and gas purification 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, including probabilistic and deterministic modeling for ComEd and PECO, 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.

ComEd, pursuant to an ICC order, and PECO, pursuant to a PAPUC order, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

At March 31, 2024 and December 31, 2023, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Accrued expenses, Other current liabilities, and Other deferred credits and other liabilities in their respective Consolidated Balance Sheets:

	March 31, 2024		December 31, 2023	
	Total Environmental Investigation and Remediation Liabilities	Portion of Total Related to MGP Investigation and Remediation	Total Environmental Investigation and Remediation Liabilities	Portion of Total Related to MGP Investigation and Remediation
Exelon	\$ 413	\$ 328	\$ 428	\$ 338
ComEd	293	292	303	302
PECO	27	25	27	25
BGE	14	11	14	11
PHI	76	—	81	—
Pepco	74	—	79	—
DPL	1	—	1	—
ACE	1	—	1	—

**Benning Road Site (Exelon, PHI, and Pepco).** In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site, which is owned by Pepco, was formerly the location of an electric generating facility owned by Pepco subsidiary, Pepco Energy Services (PES), which became a part of Generation, following the 2016 merger between PHI and Exelon. This generating facility was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services (hereinafter "Pepco Entities") with the DOEE, which requires the Pepco Entities to conduct a Remedial Investigation and Feasibility Study (RI/FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The purpose of this RI/FS is to define the nature and extent of contamination from the Benning Road site and to evaluate remedial alternatives.

Pursuant to an internal agreement between the Pepco Entities, since 2013, Pepco has performed the work required by the Consent Decree and has been reimbursed for that work by an agreed upon allocation of costs between the Pepco Entities. In September 2019, the Pepco Entities issued a draft "final" RI report which DOEE approved on February 3, 2020. The Pepco Entities are completing a FS to evaluate possible remedial alternatives for submission to DOEE. In October 2022, DOEE approved dividing the work to complete the landside portion of the FS from the waterside portion to expedite the overall schedule for completion of the project. The landside FS was approved by DOEE on March 15, 2024, and the waterside FS is scheduled to be complete and approved by DOEE by the end of the fourth quarter of 2024. Following the completion of each FS, DOEE will issue a Proposed Plan for public comment and then issue a Record of Decision (ROD) identifying the remedial actions determined to be necessary for the area in question. On October 3, 2023, DOEE and Pepco entered into an addendum to the Benning Consent Decree pursuant to which Pepco has agreed to fund or perform the remedial actions to be selected by DOEE for the landslide and water areas. This addendum to the Benning Consent Decree was entered by the Court on February 27, 2024 and became effective on that date.

As part of the separation between Exelon and Constellation in February 2022, the internal agreement between the Pepco Entities for completion and payment for the remaining Consent Decree work was memorialized in a formal agreement for post-separation activities. A second post-separation assumption agreement between Exelon and Constellation transferred any of the potential remaining remediation liability, if any, of PES/Generation to a non-utility subsidiary of Exelon which going forward will be responsible for those liabilities. Exelon, PHI, and Pepco have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

**Anacostia River Tidal Reach (Exelon, PHI, and Pepco).** Contemporaneous with the Benning Road site RI/FS being performed by the Pepco Entities, DOEE and NPS have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-District of Columbia boundary line to the confluence of the Anacostia and Potomac Rivers. The river-wide RI incorporated the results of the river sampling performed by the Pepco Entities as part of the Benning RI/FS, as well as similar sampling efforts

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor.

On September 30, 2020, DOEE released its Interim ROD for the Anacostia River sediments. The Interim ROD reflects an adaptive management approach which will require several identified "hot spots" in the river to be addressed first while continuing to conduct studies and to monitor the river to evaluate improvements and determine potential future remediation plans. The adaptive management process chosen by DOEE is less intrusive, provides more long-term environmental certainty, is less costly, and allows for site specific remediation plans already underway, including the plan for the Benning Road site to proceed to conclusion.

On July 15, 2022, Pepco received a letter from the District of Columbia's Office of the Attorney General (D.C. OAG) on behalf of DOEE conveying a settlement offer to resolve all PRPs' liability to the District of Columbia (District) for their past costs and their anticipated future costs to complete the work for the Interim ROD. Pepco responded on July 27, 2022 to enter into settlement discussions. On October 3, 2023, Pepco and the District entered into another consent decree (the "Anacostia River Consent Decree") pursuant to which Pepco agreed to pay \$47 million to resolve its liability to the District for all past costs to perform the river-wide RI/FS and all future costs to complete the work required by the Interim ROD. This amount will be paid in four equal annual installments beginning a year after the effective date of the Anacostia River Consent Decree. The funds will be deposited into the DOEE's Clean Land Fund for the District's costs of the Interim ROD work. The Anacostia River Consent Decree caps Pepco's liability for these costs and provides Pepco with the right to seek contribution from other potentially responsible parties. The Anacostia River Consent Decree was signed by the judge for the U.S. District Court for the District of Columbia and became effective on April 11, 2024. Exelon, PHI, and Pepco have accrued a liability for Pepco's payment obligations under the Anacostia Consent Decree and management's best estimate of its share of any other future Anacostia River response costs. Pepco has concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

In addition to the activities associated with the remedial process outlined above, CERCLA separately requires federal and state (here including Washington, D.C.) Natural Resource Trustees (federal or state agencies designated by the President or the relevant state, respectively, or Indian tribes) to conduct an assessment of any damages to natural resources within their jurisdiction as a result of the contamination that is being remediated. The Trustees can seek compensation from responsible parties for such damages, including restoration costs. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of a NRD assessment, a process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the very early stage of the NRD process, Pepco cannot reasonably estimate the final range of loss potentially resulting from this process.

As noted in the Benning Road Site disclosure above, as part of the separation of Exelon and Constellation in February 2022, an assumption agreement was executed transferring any potential future remediation liabilities associated with the Benning Site remediation to a non-utility subsidiary of Exelon. Similarly, any potential future liability associated with the Anacostia River Sediment Project (ARSP) was also assumed by this entity.

**Buzzard Point Site (Exelon, PHI, and Pepco).** On December 8, 2022, Pepco received a letter from the D.C. OAG, alleging wholly past violations of the District's stormwater discharge and waste disposal requirements related to operations at the Buzzard Point facility, a 9-acre parcel of waterfront property in Washington, D.C. occupied by an active substation and former steam plant building. The letter also alleged wholly past violations by Pepco of stormwater discharge requirements related to its district-wide system of underground vaults. On October 3, 2023, Pepco entered into a Consent Order with the District of Columbia to resolve the alleged violations without any admission of liability. The Consent Order requires Pepco to pay a civil penalty of \$10 million. In addition, Pepco has agreed to assess the environmental conditions at its Buzzard Point facility and conduct any remedial actions deemed necessary as a result of the assessment, and also to assess potential environmental impacts associated with the operation of its underground vaults. The Consent Order was lodged with the District of Columbia Superior Court in January 2024. The court signed and entered the Consent Order, and it became effective on February 2, 2024. Exelon, PHI, and Pepco have accrued a liability for the penalty payments and for the projected costs for the required environmental assessments and remediation. Pepco has concluded that incremental exposure is reasonably possible, but the range of loss cannot be reasonably estimated beyond the amounts included in the table above.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

### Litigation and Regulatory Matters

**DPA and Related Matters (Exelon and ComEd).** Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney's Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. On October 22, 2019, the SEC notified Exelon and ComEd that it had also opened an investigation into their lobbying activities. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation, which included a payment to the U.S. Treasury of \$200 million, which was paid in November 2020. The three-year term of the DPA ended on July 17, 2023, and on that same date the court granted the USAO's motion to dismiss the pending charge against ComEd that had been deferred by the DPA.

On September 28, 2023, Exelon and ComEd reached a settlement with the SEC, concluding and resolving in its entirety the SEC investigation, which related to the conduct identified in the DPA that was entered into by ComEd in July 2020 and successfully exited in July 2023. Under the terms of the settlement, Exelon has agreed to pay a civil penalty of \$46.2 million and Exelon and ComEd have agreed to cease and desist from committing or causing any violations and any future violations of specified provisions of the federal securities laws and rules promulgated thereunder. Exelon recorded an accrual for the full amount of the penalty in the second quarter of 2023, which was reflected in Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and in Accrued expenses on the Consolidated Balance Sheets. Exelon paid the civil penalty in full on October 4, 2023.

Subsequent to Exelon announcing the receipt of the USAO subpoenas, various lawsuits were filed, and various demand letters were received related to the subject of the subpoenas, the conduct described in the DPA and the SEC's investigation, including:

- Four putative class action lawsuits against ComEd and Exelon were filed in federal court on behalf of ComEd customers in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. On September 9, 2021, the federal court granted ComEd and Exelon's motion to dismiss and dismissed plaintiffs' federal law claim with prejudice. The federal court also dismissed the related state law claims made by the federal plaintiffs on jurisdictional grounds. Plaintiffs appealed dismissal of the federal law claim to the Seventh Circuit Court of Appeals, and refiled their state law claims in state court. On August 22, 2022, the Seventh Circuit affirmed the dismissal of the consolidated federal cases in their entirety. The time to further appeal has passed and the Seventh Circuit's decision is final.
- Three putative class action lawsuits against ComEd and Exelon were filed in Illinois state court in the third quarter of 2020 seeking restitution and compensatory damages on behalf of ComEd customers. The cases were consolidated into a single action in October of 2020. ComEd and Exelon filed a motion to dismiss on January 11, 2021. On December 23, 2021, the state court granted ComEd and Exelon's motion to dismiss with prejudice. Plaintiffs appealed the court's ruling dismissing their complaint to the First District Court of Appeals. On February 15, 2022, ComEd and Exelon moved to dismiss the federal plaintiffs' refiled state law claims, seeking dismissal on the same legal grounds asserted in their motion to dismiss the original state court plaintiffs' complaint. The court granted dismissal of the refiled state claims on February 16, 2022. The original federal plaintiffs appealed that dismissal on February 18, 2022. The two state appeals were consolidated on March 21, 2022. On September 8, 2023, the appellate court affirmed the dismissal. On December 22, 2023, plaintiffs filed a petition for leave to appeal to the Illinois Supreme Court, which ComEd and Exelon responded to on January 12, 2024. On March 27, 2024, the Illinois Supreme Court denied plaintiffs' petition for leave to appeal. The dismissal of this action is final.
- On November 3, 2022, a plaintiff filed a putative class action complaint in Lake County, Illinois Circuit Court against ComEd and Exelon for unjust enrichment and deceptive business practices in connection with the conduct giving rise to the DPA. Plaintiff seeks an accounting and disgorgement of any benefits ComEd allegedly obtained from said conduct. ComEd and Exelon filed a motion to dismiss the Complaint on February 3, 2023. On June 16, 2023, the court granted ComEd and Exelon's motion to dismiss the action with prejudice. Plaintiff filed its notice of appeal of that dismissal on July 17, 2023. On April 12, 2024, the appellate court issued its decision affirming dismissal of the action.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

- A putative class action lawsuit against Exelon and certain officers of Exelon and ComEd was filed in federal court in December 2019 alleging misrepresentations and omissions in Exelon's SEC filings related to ComEd's lobbying activities and the related investigations. The complaint was amended on September 16, 2020, to dismiss two of the original defendants and add other defendants, including ComEd. Defendants filed a motion to dismiss in November 2020. The court denied the motion in April 2021. Following mediation, the parties reached a settlement of the lawsuit, under which defendants agreed to pay plaintiffs \$173 million. On May 26, 2023, plaintiffs filed a motion for preliminary approval of the settlement, which the court granted on June 9, 2023. The court granted final settlement approval on September 7, 2023. The settlement was fully covered by insurance and has been paid in full.
- Several shareholders have sent letters to the Exelon Board of Directors since 2020 demanding, among other things, that the Exelon Board of Directors investigate and address alleged breaches of fiduciary duties and other alleged violations by Exelon and ComEd officers and directors related to the conduct described in the DPA. In the first quarter of 2021, the Exelon Board of Directors appointed a Special Litigation Committee (SLC) consisting of disinterested and independent parties to investigate and address these shareholders' allegations and make recommendations to the Exelon Board of Directors based on the outcome of the SLC's investigation. In July 2021, one of the demand letter shareholders filed a derivative action against current and former Exelon and ComEd officers and directors, and against Exelon, as nominal defendant, asserting the same claims made in its demand letter. Since that date, multiple parties have filed separate derivative lawsuits that were subsequently consolidated. On October 12, 2021, the parties filed an agreed motion to stay the litigation for 120 days in order to allow the SLC to continue its investigation, which the court granted. The stay has been extended several times. Through mediation efforts, a settlement of the derivative claims was reached by the SLC, the Independent Review Committee of the Board (which had been formed in the third quarter of 2022, to ensure the Board's consideration of any SLC recommendations would be independent and objective), the Board, and certain of the derivative shareholders. On June 16, 2023, the SLC filed a motion for preliminary approval of the settlement, attaching the Stipulation and Agreement of Settlement (Stipulation), which contains the terms of the proposed settlement. The proposed settlement terms include but are not limited to: a payment of \$40 million to Exelon by Exelon's insurers of which \$10 million constitutes the attorneys' fee award to be paid to the Settling Shareholders' counsel; various compliance and disclosure-related reforms; and certain changes in Board and Committee composition. On June 30, 2023, the court granted the non-settling shareholders' request for limited discovery into the settlement. Following that discovery, on October 26, 2023, the SLC filed its renewed motion for preliminary approval with supporting submissions filed by the Independent Review Committee, Exelon, and the settling shareholders on that same day. The parties briefing on preliminary approval was completed on January 18, 2024.

In August 2022, the ICC concluded its investigation initiated on August 12, 2021 into rate impacts of conduct admitted in the DPA, including the costs recovered from customers related to the DPA and Exelon's funding of the fine paid by ComEd. On August 17, 2022, the ICC issued its final order accepting ComEd's voluntary customer refund offer of approximately \$38 million (of which about \$31 million is ICC jurisdictional; the remaining balance is FERC jurisdictional) that resolves the question of whether customer funds were used for DPA related activities. The customer refund includes the cost of every individual or entity that was either (i) identified in the DPA or (ii) identified by ComEd as an associate of the former Speaker of the Illinois House of Representatives in the ICC proceeding. The ICC's DPA investigation is now closed. The ICC jurisdictional refund was made to customers during the April 2023 billing cycle, as required by the ICC. The FERC jurisdictional refund was included in ComEd's transmission formula rate update proceeding, filed on May 12, 2023. The filed transmission rate, inclusive of the FERC jurisdictional DPA refund, will appear on ComEd retail customers' bills for the June 2023 through May 2024 monthly billing periods, in the line designated as "Transmission Services Charge." The customer refund will not be recovered in rates or charged to customers and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon. An accrual for the amount of the customer refund has been recorded in Regulatory assets in Exelon's and ComEd's Consolidated Balance Sheets as of March 31, 2024.

**General (All Registrants).** The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The Registrants are also from time to time subject to audits and investigations by the FERC and other regulators. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 11 — Commitments and Contingencies

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.

**12. Shareholders' Equity (Exelon)**

**At-the-Market Program**

On August 4, 2022, Exelon executed an equity distribution agreement ("Equity Distribution Agreement"), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program under which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to \$1.0 billion. Exelon has no obligation to offer or sell any shares of Common stock under the Equity Distribution Agreement and may, at any time, suspend or terminate offers and sales under the Equity Distribution Agreement. In November and December 2023, Exelon issued approximately 3.6 million shares of Common stock at an average gross price of \$39.58 per share. The net proceeds from these issuances were \$140 million, which were used for general corporate purposes. As of March 31, 2024, \$858 million of Common stock remained available for sale pursuant to the ATM program.

**13. Changes in Accumulated Other Comprehensive Income (Loss) (Exelon)**

The following table presents changes in Exelon's AOCI, net of tax, by component:

Three Months Ended March 31, 2024	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items <sup>(a)</sup>	Total
<b>Balance at December 31, 2023</b>	\$ (3)	\$ (723)	\$ (726)
OCI before reclassifications	34	(24)	10
Amounts reclassified from AOCI	(1)	5	4
Net current-period OCI	\$ 33	\$ (19)	\$ 14
<b>Balance at March 31, 2024</b>	<b>\$ 30</b>	<b>\$ (742)</b>	<b>\$ (712)</b>

Three Months Ended March 31, 2023	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items <sup>(a)</sup>	Total
<b>Balance at December 31, 2022</b>	\$ 2	\$ (640)	\$ (638)
OCI before reclassifications	6	(10)	(4)
Amounts reclassified from AOCI	—	3	3
Net current-period OCI	\$ 6	\$ (7)	\$ (1)
<b>Balance at March 31, 2023</b>	<b>\$ 8</b>	<b>\$ (647)</b>	<b>\$ (639)</b>

(a) This AOCI component is included in the computation of net periodic pension and OPEB cost. See Note 14 — Retirement Benefits of the 2023 Form 10-K and Note 7 — Retirement Benefits for additional information. See Exelon's Statements of Operations and Comprehensive Income for individual components of AOCI.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 13 — Changes in Accumulated Other Comprehensive Income

The following table presents Income tax benefit (expense) allocated to each component of Exelon's Other comprehensive income (loss):

	Three Months Ended March 31,	
	2024	2023
Pension and non-pension postretirement benefit plans:		
Actuarial losses reclassified to periodic benefit cost	\$ (2)	\$ (1)
Pension and non-pension postretirement benefit plans valuation adjustments	8	3
Unrealized gains on cash flow hedges	(10)	(1)

#### 14. Supplemental Financial Information (All Registrants)

##### Supplemental Statement of Operations Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income:

	Taxes other than income taxes							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Three Months Ended March 31, 2024</b>								
Utility taxes <sup>(a)</sup>	\$ 229	\$ 75	\$ 41	\$ 31	\$ 82	\$ 74	\$ 8	\$ —
Property	105	9	4	53	38	26	11	1
Payroll	34	9	5	5	7	2	1	1
<b>Three Months Ended March 31, 2023</b>								
Utility taxes <sup>(a)</sup>	\$ 220	\$ 74	\$ 40	\$ 29	\$ 77	\$ 68	\$ 8	\$ 1
Property	99	10	4	50	35	24	11	—
Payroll	32	7	5	5	7	2	1	1

(a) The Registrants' 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 Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Other, net							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Three Months Ended March 31, 2024</b>								
AFUDC — Equity	\$ 40	\$ 10	\$ 8	\$ 7	\$ 15	\$ 12	\$ 3	\$ —
Non-service net periodic benefit cost	(7)	—	—	—	—	—	—	—
<b>Three Months Ended March 31, 2023</b>								
AFUDC — Equity	\$ 38	\$ 10	\$ 6	\$ 3	\$ 19	\$ 14	\$ 2	\$ 3
Non-service net periodic benefit cost	(1)	—	—	—	—	—	—	—

##### Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Cash Flows.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 14 — Supplemental Financial Information

	Depreciation, amortization, and accretion							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Three Months Ended March 31, 2024</b>								
Property, plant, and equipment <sup>(a)</sup>	\$ 711	\$ 284	\$ 101	\$ 122	\$ 190	\$ 81	\$ 52	\$ 53
Amortization of regulatory assets and liabilities, net <sup>(a)</sup>	166	78	3	28	56	26	9	21
Amortization of intangible assets, net <sup>(a)</sup>	2	—	—	—	—	—	—	—
ARO accretion <sup>(b)</sup>	1	—	—	—	—	—	—	—
<b>Total depreciation, amortization and accretion</b>	<b>\$ 880</b>	<b>\$ 362</b>	<b>\$ 104</b>	<b>\$ 150</b>	<b>\$ 246</b>	<b>\$ 107</b>	<b>\$ 61</b>	<b>\$ 74</b>
<b>Three Months Ended March 31, 2023</b>								
Property, plant, and equipment <sup>(a)</sup>	\$ 680	\$ 267	\$ 95	\$ 124	\$ 180	\$ 76	\$ 51	\$ 47
Amortization of regulatory assets and liabilities, net <sup>(a)</sup>	178	71	3	43	61	32	9	20
Amortization of intangible assets, net <sup>(a)</sup>	2	—	—	—	—	—	—	—
<b>Total depreciation and amortization</b>	<b>\$ 860</b>	<b>\$ 338</b>	<b>\$ 98</b>	<b>\$ 167</b>	<b>\$ 241</b>	<b>\$ 108</b>	<b>\$ 60</b>	<b>\$ 67</b>

(a) Included in Depreciation and amortization expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(b) Included in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

	Other non-cash operating activities							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Three Months Ended March 31, 2024</b>								
Pension and OPEB costs	\$ 61	\$ 17	\$ —	\$ 15	\$ 23	\$ 9	\$ 4	\$ 3
Allowance for credit losses	63	2	27	12	22	16	3	3
True-up adjustments to decoupling mechanisms and formula rates <sup>(a)</sup>	(91)	(19)	2	(43)	(31)	(29)	4	(6)
Amortization of operating ROU asset	9	—	—	2	6	1	2	1
AFUDC — Equity	(40)	(10)	(8)	(7)	(15)	(12)	(3)	—
<b>Three Months Ended March 31, 2023</b>								
Pension and OPEB costs (benefit)	\$ 45	\$ 6	\$ (3)	\$ 14	\$ 24	\$ 8	\$ 4	\$ 4
Allowance for credit losses	70	—	37	18	15	7	5	3
True-up adjustments to decoupling mechanisms and formula rates <sup>(a)</sup>	(282)	(153)	4	(65)	(68)	(39)	(11)	(18)
Long-term incentive plan	2	—	—	—	—	—	—	—
Amortization of operating ROU asset	10	1	—	1	7	1	2	1
Change in environmental liabilities	25	—	—	—	25	25	—	—
AFUDC — Equity	(38)	(10)	(6)	(3)	(19)	(14)	(2)	(3)

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
**(Dollars in millions, except per share data, unless otherwise noted)**

Note 14 — Supplemental Financial Information

- (a) For ComEd, reflects the true-up adjustments in Regulatory assets and liabilities associated with its distribution, energy efficiency, distributed generation, and transmission formula rates. For PECO, reflects the change in Regulatory assets and liabilities associated with its transmission formula rates. For BGE, Pepco, DPL, and ACE, reflects the change in Regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. See Note 3 — Regulatory Matters of the 2023 Form 10-K for additional information.

The following tables provide a reconciliation of cash, cash equivalents, and restricted cash reported within the Registrants' Consolidated Balance Sheets that sum to the total of the same amounts in their Consolidated Statements of Cash Flows.

	Cash, cash equivalents, and restricted cash							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Balance at March 31, 2024</b>								
Cash and cash equivalents	\$ 720	\$ 100	\$ 39	\$ 27	\$ 504	\$ 198	\$ 269	\$ 27
Restricted cash and cash equivalents	489	428	9	—	23	22	1	—
Restricted cash included in Other deferred debits and other assets	99	99	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,308</u>	<u>\$ 627</u>	<u>\$ 48</u>	<u>\$ 27</u>	<u>\$ 527</u>	<u>\$ 220</u>	<u>\$ 270</u>	<u>\$ 27</u>
<b>Balance at December 31, 2023</b>								
Cash and cash equivalents	\$ 445	\$ 110	\$ 42	\$ 47	\$ 180	\$ 48	\$ 16	\$ 21
Restricted cash and cash equivalents	482	402	9	1	24	24	—	—
Restricted cash included in Other deferred debits and other assets	174	174	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,101</u>	<u>\$ 686</u>	<u>\$ 51</u>	<u>\$ 48</u>	<u>\$ 204</u>	<u>\$ 72</u>	<u>\$ 16</u>	<u>\$ 21</u>
<b>Balance at March 31, 2023</b>								
Cash and cash equivalents	\$ 522	\$ 75	\$ 27	\$ 20	\$ 367	\$ 126	\$ 142	\$ 71
Restricted cash and cash equivalents	381	323	9	1	29	27	1	—
Restricted cash included in Other deferred debits and other assets	180	180	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,083</u>	<u>\$ 578</u>	<u>\$ 36</u>	<u>\$ 21</u>	<u>\$ 396</u>	<u>\$ 153</u>	<u>\$ 143</u>	<u>\$ 71</u>

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the 2023 Form 10-K.

**Supplemental Balance Sheet Information**

The following table provides additional information about material items recorded in the Registrants' Consolidated Balance Sheets.

**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 14 — Supplemental Financial Information

	Accrued expenses							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Balance at March 31, 2024</b>								
Compensation-related accruals <sup>(a)</sup>	\$ 349	\$ 102	\$ 46	\$ 46	\$ 59	\$ 19	\$ 12	\$ 8
Taxes accrued	237	214	93	140	170	135	42	16
Interest accrued	408	80	54	59	87	40	29	17
<b>Balance at December 31, 2023</b>								
Compensation-related accruals <sup>(a)</sup>	\$ 661	\$ 206	\$ 87	\$ 81	\$ 107	\$ 27	\$ 17	\$ 12
Taxes accrued	221	204	96	75	137	116	30	10
Interest accrued	414	148	49	44	72	38	13	15

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

**15. Related Party Transactions (All Registrants)**

**Service Company Costs for Corporate Support**

The Registrants receive a variety of corporate support services from BSC. Pepco, DPL, and ACE also receive corporate support services from PHISCO. See Note 1 — Significant Accounting Policies for additional information regarding BSC and PHISCO.

The following table presents the service company costs allocated to the Registrants:

	Operating and maintenance from affiliates		Capitalized costs	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2024	2023	2024	2023
<b>Exelon</b>				
BSC			\$ 158	\$ 175
PHISCO			29	24
<b>ComEd</b>				
BSC	\$ 100	\$ 83	71	81
<b>PECO</b>				
BSC		58	51	29
<b>BGE</b>				
BSC		59	54	24
<b>PHI</b>				
BSC		50	42	34
PHISCO		—	—	29
<b>Pepco</b>				
BSC		31	27	17
PHISCO		33	30	12
<b>DPL</b>				
BSC		19	17	12
PHISCO		25	24	9
<b>ACE</b>				
BSC		16	14	5
PHISCO		23	22	8



**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**  
(Dollars in millions, except per share data, unless otherwise noted)

Note 15 — Related Party Transactions

**Current Receivables from/Payables to Affiliates**

The following tables present current Receivables from affiliates and current Payables to affiliates:

**March 31, 2024**

Payables to affiliates:	Receivables from affiliates:									
	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
ComEd		\$ —	\$ —	\$ —	\$ —	\$ —	\$ 66	\$ —	\$ 6	\$ 72
PECO	\$ —						33		8	41
BGE							35		2	37
PHI							6		11	17
Pepco							19	17	1	37
DPL							13	12		25
ACE							10	12		22
Other	3			1		4				8
<b>Total</b>	<b>\$ 3</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 1</b>	<b>\$ —</b>	<b>\$ 4</b>	<b>\$ 182</b>	<b>\$ 41</b>	<b>\$ 28</b>	<b>\$ 259</b>

**December 31, 2023**

Payables to affiliates:	Receivables from affiliates:									
	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
ComEd		\$ —	\$ —	\$ —	\$ —	\$ —	\$ 64	\$ —	\$ 8	\$ 72
PECO	\$ —						36		3	39
BGE							33		2	35
PHI							5		10	15
Pepco							17	14	1	32
DPL		1					12	11	1	25
ACE		1		1	1		11	11		25
Other	3			1		3	1			8
<b>Total</b>	<b>\$ 3</b>	<b>\$ 2</b>	<b>\$ —</b>	<b>\$ 2</b>	<b>\$ 1</b>	<b>\$ 3</b>	<b>\$ 179</b>	<b>\$ 36</b>	<b>\$ 25</b>	<b>\$ 251</b>

**Borrowings from Exelon/PHI intercompany money pool**

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing both Exelon and PHI operate an intercompany money pool. PECO and PHI Corporate participate in the Exelon intercompany money pool. Pepco, DPL, and ACE participate in the PHI intercompany money pool.

**Long-term debt to financing trusts**

The following table presents Long-term debt to financing trusts:

	March 31, 2024			December 31, 2023		
	Exelon	ComEd	PECO	Exelon	ComEd	PECO
ComEd Financing III	\$ 206	\$ 205	\$ —	\$ 206	\$ 205	\$ —
PECO Trust III	81		81	81		81
PECO Trust IV	103		103	103		103
<b>Total</b>	<b>\$ 390</b>	<b>\$ 205</b>	<b>\$ 184</b>	<b>\$ 390</b>	<b>\$ 205</b>	<b>\$ 184</b>

(a)

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Dollars in millions except per share data, unless otherwise noted)

### Exelon

#### Executive Overview

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through its six reportable segments: ComEd, PECO, BGE, Pepco, DPL, and ACE. See Note 1 — Significant Accounting Policies and Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

Exelon's consolidated financial information includes the results of its seven separate operating subsidiary registrants, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

#### Financial Results of Operations

**GAAP Results of Operations.** The following table sets forth Exelon's GAAP consolidated Net income attributable to common shareholders by Registrant for the three months ended March 31, 2024 compared to the same period in 2023. For additional information regarding the financial results for the three months ended March 31, 2024 and 2023, see the discussions of Results of Operations by Registrant.

	Three Months Ended March 31,		(Unfavorable) Favorable Variance
	2024	2023	
Exelon	\$ 658	\$ 669	\$ (11)
ComEd	193	241	(48)
PECO	149	166	(17)
BGE	264	200	64
PHI	168	155	13
Pepco	75	65	10
DPL	66	60	6
ACE	29	33	(4)
Other <sup>(a)</sup>	(116)	(93)	(23)

(a) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities, and other financing and investment activities.

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023. Net income attributable to common shareholders** decreased by \$11 million and diluted earnings per average common share decreased to \$0.66 in 2024 from \$0.67 in 2023 primarily due to:

- Higher interest expense at PECO, PHI, and Exelon Corporate;
- Higher storm costs at PECO and BGE;
- Lower electric distribution earnings from lower ROE and the absence of a return on the pension asset at ComEd; and
- Lower carrying costs related to the CMC regulatory assets at ComEd.

The decreases were partially offset by:

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(a)

- The favorable impacts of rate increases at BGE and PHI; and
- Less unfavorable weather impacts at PECO.

**Adjusted (non-GAAP) operating earnings.** In addition to Net income, Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses, and other specified items. This information is intended to enhance an investor's overall understanding of year-over-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets, and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between GAAP Net income attributable to common shareholders and Adjusted (non-GAAP) operating earnings for the three months ended March 31, 2024 compared to the same period in 2023:

	Three Months Ended March 31,			
	2024		2023	
		Earnings per Diluted Share		Earnings per Diluted Share
<i>(In millions, except per share data)</i>				
<b>Net income attributable to common shareholders</b>	<b>\$ 658</b>	<b>\$ 0.66</b>	<b>\$ 669</b>	<b>\$ 0.67</b>
Mark-to-market impact of economic hedging activities (net of taxes of \$0)	—	—	(1)	—
Change in environmental liabilities (net of taxes of \$7)	—	—	18	0.02
Separation costs (net of taxes of \$0) <sup>(a)</sup>	—	—	(1)	—
Change in FERC audit liability (net of taxes of \$9 and \$4, respectively)	27	0.03	11	0.01
<b>Adjusted (non-GAAP) operating earnings</b>	<b>\$ 685</b>	<b>\$ 0.68</b>	<b>\$ 696</b>	<b>\$ 0.70</b>

Note:

Amounts may not sum due to rounding.

Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net income attributable to common shareholders and Adjusted (non-GAAP) operating earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. The marginal statutory income tax rates for 2024 and 2023 ranged from 24.0% to 29.0%.

- (a) Represents costs related to the separation primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation, and employee-related severance costs, which are recorded in Operating and maintenance expense and Other, net.

## Significant 2024 Transactions and Developments

### *Distribution Base Rate Case Proceedings*

The Utility Registrants file base rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future financial statements.

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2024. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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*Completed Distribution Base Rate Case Proceedings*

<u>Registrant/Jurisdiction</u>	<u>Filing Date</u>	<u>Service</u>	<u>Requested Revenue Requirement Increase</u>	<u>Approved Revenue Requirement Increase</u>	<u>Approved ROE</u>	<u>Approval Date</u>	<u>Rate Effective Date</u>
ComEd - Illinois	January 17, 2023	Electric	\$ 1,487	\$ 501	8.905%	December 14, 2023	January 1, 2024
			\$ 838	\$ 810	8.905%	April 18, 2024	May 1, 2024
	April 21, 2023	Electric	\$ 247	\$ 259	8.91%	November 30, 2023	January 1, 2024
BGE - Maryland	February 17, 2023	Electric	\$ 313	\$ 179	9.50 %	December 14, 2023	January 1, 2024
		Natural Gas	\$ 289	\$ 229	9.45 %		
Pepco - Maryland	October 26, 2020 (amended March 31, 2021)	Electric	\$ 104	\$ 52	9.55 %	June 28, 2021	June 28, 2021
DPL - Maryland	May 19, 2022	Electric	\$ 38	\$ 29	9.60 %	December 14, 2022	January 1, 2023
DPL - Delaware	December 15, 2022 (amended September 29, 2023)	Electric	\$ 39	\$ 28	9.60 %	April 18, 2024	July 15, 2023
ACE - New Jersey	February 15, 2023 (amended August 21, 2023)	Electric	\$ 92	\$ 45	9.60 %	November 17, 2023	December 1, 2023

*Pending Distribution Base Rate Case Proceedings*

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois	March 15, 2024	Electric	\$ 670	8.905%	December 2024
	April 26, 2024	Electric	\$ 627	9.89%	December 2024
PECO - Pennsylvania	March 28, 2024	Electric	\$ 464	10.95%	Fourth quarter of 2024
		Natural Gas	\$ 111	11.15%	
Pepco - District of Columbia	April 13, 2023 (amended February 27, 2024)	Electric	\$ 186	10.50 %	Third quarter of 2024
Pepco - Maryland	May 16, 2023 (amended February 23, 2024)	Electric	\$ 186	10.50 %	Second quarter of 2024

**Transmission Formula Rates**

For 2024, the following total increases/(decreases) were included in ComEd's and BGE's electric transmission formula rate updates. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase	Annual Reconciliation (Decrease) Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
ComEd	\$ 32	\$ (12)	\$ 20	8.14 %	11.50 %
BGE	\$ 42	\$ 13	\$ 53	7.47 %	10.50 %

**ComEd's FERC Audit**

The Utility Registrants are subject to periodic audits and investigations by FERC. FERC's Division of Audits and Accounting initiated a nonpublic audit of ComEd in April 2021 evaluating ComEd's compliance with (1) approved terms, rates and conditions of its federally regulated service; (2) accounting requirements of the Uniform System of Accounts; (3) reporting requirements of the FERC Form 1; and (4) the requirements for record retention. The audit period extends back to January 1, 2017.

On July 27, 2023, FERC issued a final audit report which included, among other things, findings and recommendations related to ComEd's methodology regarding the allocation of certain overhead costs to capitalized construction costs under FERC regulations, including a suggestion that refunds may be due to customers for amounts collected in previous years. On August 28, 2023, ComEd filed a formal notice of the issues it will contest. On December 14, 2023, FERC appointed a settlement judge for the contested overhead allocation findings and set the matter for a trial-type hearing. That hearing process has been held in abeyance while a formal settlement process, which began in February 2024, takes place. Based on the preliminary findings and the ongoing settlement process, ComEd determined that a loss was probable and recorded its regulatory liability to reflect its best estimate of that loss. The final outcome and resolution of any contested audit issues as well as a reasonable estimate of potential future losses cannot be accurately estimated at this stage; however, the final resolution of these matters could result in recognition of future losses, above the amounts currently accrued, that could be material to the Exelon and ComEd financial statements.

## Other Key Business Drivers and Management Strategies

The following discussion of other key business drivers and management strategies includes current developments of previously disclosed matters and new issues arising during the period that may impact future financial statements. This section should be read in conjunction with ITEM 1. Business in the 2023 Form 10-K, ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Key Business Drivers and Management Strategies in the 2023 Form 10-K, and Note 11 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in this report for additional information on various environmental matters.

### Legislative and Regulatory Developments

#### *Infrastructure Investment and Jobs Act*

On November 15, 2021, President Biden signed the \$1.2 trillion IIJA into law. IIJA provides for approximately \$550 billion in new federal spending. Categories of funding include funding for a variety of infrastructure needs, including but not limited to: (1) power and grid reliability and resilience, (2) resilience for cybersecurity to address critical infrastructure needs, and (3) electric vehicle charging infrastructure for alternative fuel corridors. Federal agencies are developing guidelines to implement spending programs under IIJA. The time needed to develop these guidelines will vary with some limited program applications opened as early as the first quarter of 2022. The Registrants continue to evaluate programs under the legislation and consider possible opportunities to apply for funding, either directly or in potential collaborations with state and/or local agencies and key stakeholders. The Registrants cannot predict the ultimate timing and success of securing funding from programs under IIJA.

In March 2023, Exelon, ComEd, and PHI submitted three applications related to the Smart Grid Grants program under section 40107 of IIJA. These applications are focused on replacing existing Advanced Distribution Management Systems (ADMS) in support of distributed energy resources (DERs) and grid-edged technologies, strengthening interoperability and data architecture of systems in support of two-way power flows and accelerating advanced metering deployment in disadvantaged communities. In October 2023, ComEd's project, Deployment of a Community-Oriented Interoperable Control Framework for Aggregating and Integrating Distributed Energy Resources and Other Grid-Edge Devices, was recommended by the Grid Deployment Office (GDO) for negotiation of a final award up to \$50 million. This project will enable ComEd and its local partners to deploy the next generation of grid technologies that support the growth of solar and electric vehicles (EVs), while piloting new local workforce training initiatives to support job creation connected to the clean energy transition. The award negotiation process is currently ongoing.

In April 2023, ComEd, PECO, BGE, and PHI submitted seven applications related to the Grid Resilience Grants program under section 40101(c) of IIJA. These applications are broadly focused on improving grid resilience with an emphasis on disadvantaged communities, relief of capacity constraints and modernizing infrastructure, deployment of DER and microgrid technologies and providing improved resilience through storm hardening projects. In October 2023, PECO's project, Creating a Resilient, Equitable, and Accessible Transformation in Energy for Greater Philadelphia (CREATE), was recommended by the GDO for negotiation of a final award up to \$100 million. This project will support critical electric infrastructure investments to help reduce the impact of extreme weather and historic flooding on the Registrants' electric distribution system. The award negotiation process is currently ongoing.

The Registrants are supporting three different Regional Clean Hydrogen Hub opportunities, covering all five states that Exelon operates in plus Washington D.C. under a program that will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier that can deliver or store energy. Applications for the three opportunities under this program were submitted in April 2023. In October 2023 the DOE announced it selected two of the projects for further negotiation: (1) the Mid-Atlantic Clean Hydrogen Hub (MACH2), which is being supported by PECO and PHI, and (2) the Midwest Alliance for Clean Hydrogen (MachH2), which is being supported by ComEd.

In November 2023, the GDO announced up to \$3.9 billion available through the second-round funding opportunity of the Grid Resilience and Innovation Partnerships (GRIP) Program for Fiscal Years 2024 and 2025. This funding opportunity focuses on projects that will improve electric transmission by increasing funding and advancing interconnection processes for faster build out of energy projects, create comprehensive solutions that

link grid communications systems and operations to increase resilience and reduce power outages and threats, and deploy advanced technologies such as distributed energy resources and battery systems to provide essential grid services to ensure American communities across the country have access to affordable, reliable, clean electricity. In January 2024, Exelon, ComEd, BGE, PHI, Pepco, DPL, and ACE submitted seven concept papers in response to the second round of the GRIP program. The concept papers were focused on improving the resilience of the electric grid and deployment of technologies to enhance grid flexibility and deliver benefits to customers and communities across the Exelon footprint. Six of the seven concept papers submitted received notifications of encouragement to submit a full application. Exelon, BGE, PHI, Pepco, DPL, and ACE are in the process of evaluating the development and submission of final applications. Formal applications for Topic Area 1 (Grid Resilience) and Topic Area 3 (Grid Innovation) were due on April 17, 2024. ACE in coordination with the NJBPU Division of Clean Energy submitted an application for Topic Area 3 to expand DER hosting capacity through integrated grid enhancing technologies. Formal applications for Topic Area 2 (Smart Grid Grants) are due on May 22, 2024. The GDO is expected to announce award notification in the second half of 2024. Exelon, BGE, PHI, Pepco, DPL and ACE cannot predict if their applications will be selected for negotiation of a final award.

## **Critical Accounting Policies and Estimates**

Management of each of the Registrants makes a number of significant estimates, assumptions, and judgments in the preparation of its financial statements. As of March 31, 2024, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2023. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the 2023 Form 10-K for further information.

## Results of Operations by Registrant

### Results of Operations — ComEd

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2024	2023	
<b>Operating revenues</b>	\$ 2,095	\$ 1,667	\$ 428
<b>Operating expenses</b>			
Purchased power	907	488	(419)
Operating and maintenance	418	337	(81)
Depreciation and amortization	362	338	(24)
Taxes other than income taxes	94	93	(1)
Total operating expenses	<u>1,781</u>	<u>1,256</u>	<u>(525)</u>
<b>Operating income</b>	<u>314</u>	<u>411</u>	<u>(97)</u>
<b>Other income and (deductions)</b>			
Interest expense, net	(122)	(117)	(5)
Other, net	20	18	2
Total other income and (deductions)	<u>(102)</u>	<u>(99)</u>	<u>(3)</u>
<b>Income before income taxes</b>	<u>212</u>	<u>312</u>	<u>(100)</u>
<b>Income taxes</b>	<u>19</u>	<u>71</u>	<u>52</u>
<b>Net income</b>	<u>\$ 193</u>	<u>\$ 241</u>	<u>\$ (48)</u>

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023.** Net income decreased by \$48 million as compared to the same period in 2023, primarily due to decreases in electric distribution earnings reflecting lower allowed ROE.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase (Decrease)	
Distribution	\$	34
Transmission		2
Energy efficiency		20
Other		(5)
		<u>51</u>
Regulatory required programs		377
Total increase	<u>\$</u>	<u>428</u>

**Revenue Decoupling.** The demand for electricity is affected by weather and customer usage. Operating revenues are not impacted by abnormal weather, usage per customer, or number of customers as a result of revenue decoupling mechanisms.

**Distribution Revenue.** Distribution revenues were under a performance-based formula rate through 2023. Starting in 2024, distribution revenues are under a MRP. Both the performance-based formula rate and the MRP require annual reconciliations of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred with certain limitations for the MRP reconciliations. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, (e.g., severe weather and storm restoration), investments being recovered, and allowed ROE. Electric distribution revenue increased for the three months ended March 31, 2024 as compared to the same period in 2023, due to higher fully recoverable costs offset by lower allowed ROE.

**Transmission Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak

(a)

load, which is updated annually in January based on the prior calendar year. Transmission revenue increased for the three months ended March 31, 2024 as compared to the same period in 2023, primarily due to higher peak load.

**Energy Efficiency Revenue.** Energy efficiency revenues are under a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased for the three months ended March 31, 2024 as compared to the same period in 2023, primarily due to increased regulatory asset amortization, which is fully recoverable.

**Other Revenue** primarily includes assistance provided to other utilities through mutual assistance programs. Other revenue decreased for the three months ended March 31, 2024 as compared to the same period in 2023, which primarily reflects less mutual assistance revenues associated with storm restoration efforts.

**Regulatory Required Programs** represents revenues collected under approved riders to recover costs incurred for regulatory programs such as recoveries under the credit loss expense tariff, environmental costs associated with MGP sites, ETAC, and costs related to electricity, ZEC, CMC, and REC procurement. ETAC is a retail customer surcharge collected and remitted to an Illinois state agency for programs to support clean energy jobs and training. The riders are designed to provide full and current cost recovery. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries as ComEd remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ComEd either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ComEd, ComEd is permitted to recover the electricity, ZEC, CMC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, CMCs, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The increase of \$419 million for the three months ended March 31, 2024 compared to the same period in 2023, in **Purchased power expense** is offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>	
	<b>Increase</b>	
Labor, other benefits, contracting and materials	\$	45
BSC costs		17
Storm-related costs		6
Pension and non-pension postretirement benefits expense		6
Other		3
		<u>77</u>
Regulatory required programs <sup>(a)</sup>		<u>4</u>
Total increase	\$	<u>81</u>

(a) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism.

The changes in **Depreciation and amortization expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>	
	<b>Increase</b>	
Depreciation and amortization <sup>(a)</sup>	\$	16
Regulatory asset amortization <sup>(b)</sup>		8
<b>Total increase</b>	<b>\$</b>	<b>24</b>

(a) Reflects ongoing capital expenditures.

(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset.

**Effective income tax rates** were 9.0% and 22.8% for the three months ended March 31, 2024 and 2023, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations — PECO**

	Three Months Ended March 31,		(Unfavorable) Favorable Variance
	2024	2023	
<b>Operating revenues</b>	\$ 1,054	\$ 1,112	\$ (58)
<b>Operating expenses</b>			
Purchased power and fuel	403	484	81
Operating and maintenance	293	270	(23)
Depreciation and amortization	104	98	(6)
Taxes other than income taxes	51	50	(1)
Total operating expenses	851	902	51
<b>Gain on sales of assets</b>	2	—	2
<b>Operating income</b>	205	210	(5)
<b>Other income and (deductions)</b>			
Interest expense, net	(55)	(48)	(7)
Other, net	9	8	1
Total other income and (deductions)	(46)	(40)	(6)
<b>Income before income taxes</b>	159	170	(11)
<b>Income taxes</b>	10	4	(6)
<b>Net income</b>	\$ 149	\$ 166	\$ (17)

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023.** Net income decreased by \$17 million, due to an increase in operating expenses as a result of higher storm costs and an increase in interest expense, partially offset by an increase in revenue as a result of less unfavorable weather impact relative to the same period last year.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2024		
	Increase (Decrease)		
	Electric	Gas	Total
<b>Weather</b>	\$ 12	\$ 12	\$ 24
Volume	(2)	(2)	(4)
Pricing	1	3	4
Transmission	8	—	8
Other	(4)	(3)	(7)
	15	10	25
<b>Regulatory required programs</b>	(30)	(53)	(83)
<b>Total decrease</b>	\$ (15)	\$ (43)	\$ (58)

**Weather.** The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2024 compared to the same period in 2023, Operating revenues related to weather increased due to less unfavorable weather conditions in PECO's service territory.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in

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(a)

(b)

(a)

(b)

PECO's service territory for the three months ended March 31, 2024 compared to the same period in 2023 and normal weather consisted of the following:

PECO Service Territory	Three Months Ended March 31,			% Change	
	2024	2023	Normal	2024 vs. 2023	2024 vs. Normal
Heating Degree-Days	2,089	1,888	2,410	10.6 %	(13.3)%
Cooling Degree-Days	—	—	1	N/A	(100.0)%

**Volume.** Electric volume, exclusive of the effects of weather, for the three months ended March 31, 2024 compared to the same period in 2023, remained relatively consistent. Natural gas volume for the three months ended March 31, 2024 compared to the same period in 2023, remained relatively consistent.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,			% Change	Weather - Normal % Change <sup>(b)</sup>
	2024	2023			
Residential	3,455	3,358		2.9 %	(1.2)%
Small commercial & industrial	1,891	1,843		2.6 %	(1.7)%
Large commercial & industrial	3,355	3,237		3.6 %	2.5 %
Public authorities & electric railroads	179	168		6.5 %	7.1 %
Total electric retail deliveries <sup>(a)</sup>	8,880	8,606		3.2 %	0.2 %

Number of Electric Customers	At March 31,	
	2024	2023
Residential	1,540,491	1,529,779
Small commercial & industrial	156,475	155,846
Large commercial & industrial	3,160	3,118
Public authorities & electric railroads	10,713	10,401
Total	1,710,839	1,699,144

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Natural Gas Deliveries to Customers (in mmcf)	Three Months Ended March 31,			% Change	Weather - Normal % Change <sup>(b)</sup>
	2024	2023			
Residential	18,895	17,190		9.9 %	0.6 %
Small commercial & industrial	9,488	8,699		9.1 %	(0.8)%
Large commercial & industrial	16	29		(44.8)%	(12.2)%
Transportation	6,899	7,014		(1.6)%	(3.0)%
Total natural gas retail deliveries <sup>(a)</sup>	35,298	32,932		7.2 %	(0.5)%

Number of Natural Gas Customers	At March 31,	
	2024	2023
Residential	508,429	504,181
Small commercial & industrial	45,038	45,003
Large commercial & industrial	7	9
Transportation	646	650
Total	554,120	549,843

(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

**Pricing** for the three months ended March 31, 2024 compared to the same period in 2023 remained relatively consistent.

(a)

**Transmission Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered.

**Other revenue** primarily includes revenue related to late payment charges. Other revenue for the three months ended March 31, 2024 compared to the same period in 2023 remained relatively consistent.

**Regulatory Required Programs** represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as PECO remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, PECO either acts as the billing agent or the competitive supplier separately bills its own customers and therefore PECO does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from PECO, PECO is permitted to recover the electricity, natural gas, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power and fuel expense related to the electricity, natural gas, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The decrease of \$81 million for the three months ended March 31, 2024 compared to the same period in 2023, in **Purchased power and fuel expense** is offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase (Decrease)	
Storm-related costs	\$	25
BSC costs		7
Pension and non-pension postretirement benefit expense		2
Labor, other benefits, contracting and materials		(6)
Credit loss expense		(10)
Other		7
		<u>25</u>
Regulatory required programs		(2)
Total increase	\$	<u>23</u>

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase	
Depreciation and amortization <sup>(a)</sup>	\$	6
Regulatory asset amortization		—
Total increase	\$	<u>6</u>

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.



**Interest expense, net** increased \$7 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily due to an increase in interest rates and the issuance of debt in the second quarter of 2023.

**Effective income tax rates** were 6.3% and 2.4% for the three months ended March 31, 2024 and 2023, respectively, See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations — BGE**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2024	2023	
<b>Operating revenues</b>	\$ 1,297	\$ 1,257	\$ 40
<b>Operating expenses</b>			
Purchased power and fuel	464	492	28
Operating and maintenance	264	222	(42)
Depreciation and amortization	150	167	17
Taxes other than income taxes	89	83	(6)
Total operating expenses	967	964	(3)
<b>Operating income</b>	330	293	37
<b>Other income and (deductions)</b>			
Interest expense, net	(50)	(44)	(6)
Other, net	8	3	5
Total other income and (deductions)	(42)	(41)	(1)
<b>Income before income taxes</b>	288	252	36
<b>Income taxes</b>	24	52	28
<b>Net income</b>	\$ 264	\$ 200	\$ 64

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023. Net Income** increased \$64 million primarily due to favorable impacts of the multi-year plans, partially offset by an increase in storm costs, an increase in property tax expense, and an increase in interest expense. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric and natural gas distribution multi-year plans.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2024		
	Increase (Decrease)		
	Electric	Gas	Total
Distribution	\$ 23	\$ 44	\$ 67
Transmission	(1)	—	(1)
Other	(1)	(2)	(3)
	21	42	63
Regulatory required programs	47	(70)	(23)
Total increase (decrease)	\$ 68	\$ (28)	\$ 40

**Revenue Decoupling.** The demand for electricity and natural gas is affected by weather and customer usage. However, Operating revenues are not impacted by abnormal weather or usage per customer as a result of a monthly rate adjustment that provides for fixed distribution revenue per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

	At March 31,	
	2024	2023
<b>Number of Electric Customers</b>		
Residential	1,213,063	1,207,486
Small commercial & industrial	115,406	115,658
Large commercial & industrial	13,110	12,911
Public authorities & electric railroads	261	266
Total	1,341,840	1,336,321



Number of Natural Gas Customers	At March 31,	
	2024	2023
Residential	658,818	656,583
Small commercial & industrial	37,982	38,260
Large commercial & industrial	6,336	6,261
Total	703,136	701,104

**Distribution Revenue** increased for the three months ended March 31, 2024, compared to the same period in 2023, due to favorable impacts of the multi-year plans.

**Transmission Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue remained relatively the same for the three months ended March 31, 2024, compared to the same period in 2023.

**Other Revenue** includes revenue related to late payment, charges, mutual assistance, off-system sales, and service application fees. Other Revenue decreased for the three months ended March 31, 2024 compared to the same period in 2023.

**Regulatory Required Programs** represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, and the POLR mechanism. The riders are designed to provide full and current cost recovery, as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as BGE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, BGE acts as the billing agent and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from BGE, BGE is permitted to recover the electricity and natural gas procurement costs from customers and therefore records the amounts related to the electricity and/or natural gas in Operating revenues and Purchased power and fuel expense. BGE recovers electricity and natural gas procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The decrease of \$28 million for the three months ended March 31, 2024 compared to the same period in 2023, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>
	<b>Increase (Decrease)</b>
Storm-related costs	10
BSC costs	5
Credit loss expense	(6)
Labor, other benefits, contracting, and materials	(3)
	6
Regulatory required programs <sup>(a)</sup>	36
<b>Total increase</b>	<b>\$ 42</b>

(a) Increase due to the cost recovery associated with Empower Maryland. Please refer to 2023 10-K Note 3 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>
	<b>Increase (Decrease)</b>
Depreciation and amortization	\$ 1
Regulatory required programs <sup>(a)</sup>	(25)
Regulatory asset amortization	7
<b>Total decrease</b>	<b>\$ (17)</b>

(a) Decrease due to the cost recovery associated with Empower Maryland. Please refer to 2023 10-K Note 3 — Regulatory Matters for additional information.

**Interest expense, net** increased by \$6 million for the three months ended March 31, 2024, respectively compared to the same period in 2023, primarily due to the issuance of debt during the second quarter of 2023.

**Taxes other than income taxes** increased by \$6 million for the three months ended March 31, 2024, respectively, compared to the same period in 2023, primarily due to increased property taxes.

**Effective income tax rates** were 8.3% and 20.6% for the three months ended March 31, 2024 and 2023, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations — PHI**

PHI's Results of Operations include the results of its three reportable segments, Pepco, DPL, and ACE. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services, and the costs are directly charged or allocated to the applicable subsidiaries. Additionally, the results of PHI's corporate operations include interest costs from various financing activities. All material intercompany accounts and transactions have been eliminated in consolidation. The following table sets forth PHI's GAAP consolidated Net income, by Registrant, for the three months ended March 31, 2024 compared to the same period in 2023. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2024	2023	
PHI	\$ 168	\$ 155	\$ 13
Pepco	75	65	10
DPL	66	60	6
ACE	29	33	(4)
Other <sup>(a)</sup>	(2)	(3)	1

(a) Primarily includes eliminating and consolidating adjustments, PHI's corporate operations, shared service entities, and other financing and investment activities.

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023. Net Income** increased by \$13 million primarily due to the absence of an increase environmental liabilities, an increase in ACE and DPL Delaware electric distribution rates, favorable impacts of the Pepco Maryland and DPL Maryland multi-year plans, and higher transmission rates at Pepco and DPL, partially offset by an increase in interest expense and various operating expenses.

**Results of Operations — Pepco**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2024	2023	
<b>Operating revenues</b>	\$ 759	\$ 710	\$ 49
<b>Operating expenses</b>			
Purchased power	281	258	(23)
Operating and maintenance	150	150	—
Depreciation and amortization	107	108	1
Taxes other than income taxes	102	94	(8)
Total operating expenses	640	610	(30)
<b>Operating income</b>	119	100	19
<b>Other income and (deductions)</b>			
Interest expense, net	(45)	(39)	(6)
Other, net	15	16	(1)
Total other income and (deductions)	(30)	(23)	(7)
<b>Income before income taxes</b>	89	77	12
<b>Income taxes</b>	14	12	(2)
<b>Net income</b>	\$ 75	\$ 65	\$ 10

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023.** Net income increased by \$10 million primarily due to the absence of an increase in environmental liabilities, favorable impacts of the Maryland multi-year plan, customer growth, and higher transmission rates, partially offset by an increase in interest expense, credit loss expense, and depreciation expense.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase	
Distribution	\$	9
Transmission		9
Other		—
Regulatory required programs		18
		31
Total increase	\$	49

**Revenue Decoupling.** The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in both Maryland and the District of Columbia are not impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

Number of Electric Customers	At March 31,	
	2024	2023
Residential	869,606	859,207
Small commercial & industrial	54,177	54,089
Large commercial & industrial	22,992	22,858
Public authorities & electric railroads	207	201
Total	946,982	936,355

(a)

(b)

**Distribution Revenue** increased for the three months ended March 31, 2024 compared to the same period in 2023 primarily due to favorable impacts of the Maryland multi-year plan, and customer growth.

**Transmission Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the three months ended March 31, 2024, compared to the same period in 2023, primarily due to increases in underlying costs and capital investment.

**Other Revenue** includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

**Regulatory Required Programs** represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG, and SOS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as Pepco remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, Pepco acts as the billing agent and therefore, Pepco does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from Pepco, Pepco is permitted to recover the electricity and REC procurement costs from customers and therefore records the amounts related to the electricity and RECs in Operating revenues and Purchased power expense. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The increase of \$23 million for the three months ended March 31, 2024 compared to the same period in 2023, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>	
	<b>Increase (Decrease)</b>	
BSC and PHISCO costs	\$	7
Credit loss expense		7
Pension and non-pension postretirement benefits expense		(1)
Labor, other benefits, contracting and materials <sup>(a)</sup>		(22)
Other		1
		(8)
Regulatory required programs <sup>(b)</sup>		8
Total increase	\$	—

(a) Primarily reflects the absence of an increase in environmental liabilities for the three months ended March 31, 2024 compared to the same period in 2023.

(b) Increase due to the cost recovery associated with Empower Maryland. Please refer to 2023 10-K Note 3 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>	
	<b>Increase (Decrease)</b>	
Depreciation and amortization <sup>(a)</sup>	\$	5
Regulatory asset amortization		—
Regulatory required programs		(6)
Total decrease	\$	(1)

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

**Taxes other than income taxes** increased \$8 million for the or the three months ended March 31, 2024 compared to the same period in 2023, primarily due to an increase in property taxes.

**Interest expense, net** increased by \$6 million for the three months ended March 31, 2024 compared to the same period in 2023, primarily due to an increase in interest rates and the issuance of debt in 2023 and 2024.

**Effective income tax rates** were 15.7% and 15.6% for the three months ended March 31, 2024 and 2023, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations — DPL**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2024	2023	
<b>Operating revenues</b>	\$ 491	\$ 474	\$ 17
<b>Operating expenses</b>			
Purchased power and fuel	215	221	6
Operating and maintenance	95	87	(8)
Depreciation and amortization	61	60	(1)
Taxes other than income taxes	20	20	—
Total operating expenses	391	388	(3)
<b>Operating income</b>	100	86	14
<b>Other income and (deductions)</b>			
Interest expense, net	(22)	(17)	(5)
Other, net	5	3	2
Total other income and (deductions)	(17)	(14)	(3)
<b>Income before income taxes</b>	83	72	11
<b>Income taxes</b>	17	12	(5)
<b>Net income</b>	\$ 66	\$ 60	\$ 6

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023.** Net income increased \$6 million primarily due to an increase in Delaware electric distribution rates, higher transmission rates, and favorable impacts of the Maryland multi-year plan, partially offset by an increase in interest expense.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2024		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ 3	\$ 3	\$ 6
Volume	(1)	(1)	(2)
Distribution	10	1	11
Transmission	7	—	7
Other	2	—	2
	21	3	24
Regulatory required programs	21	(28)	(7)
Total increase (decrease)	\$ 42	\$ (25)	\$ 17

**Revenue Decoupling.** The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in Maryland are not impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer by customer class. While Operating revenues from electric distribution customers in Maryland are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

**Weather.** The demand for electricity and natural gas in Delaware is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2024, compared to the same period in 2023, Operating revenues related to weather increased due to favorable weather conditions in Delaware electric and natural gas service territories.

(a)

(b)

(a)

(b)

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in the Delaware electric service territory and a 30-year period in the Delaware natural gas service territory. The changes in heating and cooling degree days in the Delaware service territory for the three months ended March 31, 2024 compared to same period in 2023 and normal weather consisted of the following:

<b>Delaware Electric Service Territory</b>	<b>Three Months Ended March 31,</b>		<b>Normal</b>	<b>% Change</b>	
	<b>2024</b>	<b>2023</b>		<b>2024 vs. 2023</b>	<b>2024 vs. Normal</b>
Heating Degree-Days	2,204	1,952	2,447	12.9 %	(9.9)%
Cooling Degree-Days	—	—	1	— %	(100.0)%

<b>Delaware Natural Gas Service Territory</b>	<b>Three Months Ended March 31,</b>		<b>Normal</b>	<b>% Change</b>	
	<b>2024</b>	<b>2023</b>		<b>2024 vs. 2023</b>	<b>2024 vs. Normal</b>
Heating Degree-Days	2,204	1,952	2,476	12.9 %	(11.0)%

**Volume**, exclusive of the effects of weather, remained relatively consistent for the three months ended March 31, 2024 compared to the same period in 2023.

<b>Electric Retail Deliveries to Delaware Customers (in GWhs)</b>	<b>Three Months Ended March 31,</b>		<b>% Change</b>	<b>Weather - Normal % Change<sup>(b)</sup></b>
	<b>2024</b>	<b>2023</b>		
Residential	857	797	7.5 %	(0.4)%
Small commercial & industrial	339	327	3.7 %	(0.3)%
Large commercial & industrial	718	719	(0.1)%	(1.0)%
Public authorities & electric railroads	7	9	(22.2)%	(24.7)%
<b>Total electric retail deliveries<sup>(a)</sup></b>	<b>1,921</b>	<b>1,852</b>	<b>3.7 %</b>	<b>(0.7)%</b>

<b>Number of Total Electric Customers (Maryland and Delaware)</b>	<b>At March 31,</b>	
	<b>2024</b>	<b>2023</b>
Residential	486,950	482,979
Small commercial & industrial	64,338	63,794
Large commercial & industrial	1,260	1,236
Public authorities & electric railroads	593	595
<b>Total</b>	<b>553,141</b>	<b>548,604</b>

(a) Reflects delivery volumes from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

<b>Natural Gas Retail Deliveries to Delaware Customers (in mmcf)</b>	<b>Three Months Ended March 31,</b>		<b>% Change</b>	<b>Weather - Normal % Change<sup>(b)</sup></b>
	<b>2024</b>	<b>2023</b>		
Residential	3,913	3,581	9.3 %	(1.2)%
Small commercial & industrial	1,717	1,652	3.9 %	(6.8)%
Large commercial & industrial	428	414	3.4 %	3.5 %
Transportation	1,960	1,900	3.2 %	(1.9)%
<b>Total natural gas deliveries<sup>(a)</sup></b>	<b>8,018</b>	<b>7,547</b>	<b>6.2 %</b>	<b>(2.4)%</b>

<u>Number of Delaware Natural Gas Customers</u>	<u>At March 31,</u>	
	<u>2024</u>	<u>2023</u>
Residential	130,427	129,791
Small commercial & industrial	10,182	10,158
Large commercial & industrial	16	16
Transportation	163	158
<b>Total</b>	<b>140,788</b>	<b>140,123</b>

(a) Reflects delivery volumes from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

**Distribution Revenue** increased for the three months ended March 31, 2024 compared to the same period in 2023 primarily due to favorable impacts of the higher electric distribution rates in Delaware that became effective July 2023, favorable impacts of the Maryland multi-year plan that became effective in January 2024, and higher natural gas DSIC rates in Delaware that became effective in January 2024, partially offset by lower electric DSIC rates in Delaware that became effective in January 2024.

**Transmission Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. During the three months ended March 31, 2024 compared to the same period in 2023, transmission revenue increased primarily due to increases in underlying costs and capital investment.

**Other Revenue** includes rental revenue, service connection fees, and mutual assistance revenues.

**Regulatory Required Programs** represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DE Renewable Portfolio Standards, SOS procurement and administrative costs, and GCR costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. All customers have the choice to purchase electricity from competitive electric generation suppliers; however, only certain commercial and industrial customers have the choice to purchase natural gas from competitive natural gas suppliers. Customer choice programs do not impact the volume of deliveries as DPL remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, DPL either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from DPL, DPL is permitted to recover the electricity, natural gas, and REC procurement costs from customers and therefore records the amounts related to the electricity, natural gas, and RECs in Operating revenues and Purchased power and fuel expense. DPL recovers electricity and REC procurement costs from customers with a slight mark-up, and natural gas costs without mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The decrease of \$6 million for the three months ended March 31, 2024, compared to the same period in 2023, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>	
	<b>Increase (Decrease)</b>	
Storm-related Costs	\$	6
BSC and PHISCO costs		3
Labor and contracting		2
Credit loss expense		(2)
Other		(1)
		8
Regulatory required programs		—
Total increase	\$	8

The changes in **Depreciation and amortization expense** consisted of the following:

	<b>Three Months Ended March 31, 2024</b>	
	<b>Increase</b>	
Depreciation and amortization <sup>(a)</sup>	\$	1
Regulatory required programs		—
Regulatory asset amortization		—
Total increase	\$	1

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

**Interest expense, net** increased by \$5 million for the three months ended March 31, 2024 compared to the same period in 2023, primarily due to an increase in interest rates and the issuance of debt in 2023 and 2024.

**Effective income tax rates** were 20.5% and 16.7% for the three months ended March 31, 2024 and 2023, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations — ACE**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2024	2023	
<b>Operating revenues</b>	\$ 358	\$ 353	\$ 5
<b>Operating expenses</b>			
Purchased power	140	148	8
Operating and maintenance	87	81	(6)
Depreciation and amortization	74	67	(7)
Taxes other than income taxes	2	2	—
Total operating expenses	303	298	(5)
<b>Operating income</b>	55	55	—
<b>Other income and (deductions)</b>			
Interest expense, net	(20)	(16)	(4)
Other, net	5	5	—
Total other income and (deductions)	(15)	(11)	(4)
<b>Income before income taxes</b>	40	44	(4)
<b>Income taxes</b>	11	11	—
<b>Net income</b>	\$ 29	\$ 33	\$ (4)

**Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023.** Net income decreased by \$4 million primarily due to an increase in various operating expenses, depreciation expense, and interest expense, partially offset by an increase in distribution rates.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase (Decrease)	
Distribution	\$	11
Transmission		2
Other		1
		14
Regulatory required programs		(9)
Total increase	\$	5

**Revenue Decoupling.** The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in New Jersey are not impacted by abnormal weather or usage per customer as a result of the CIP which became effective, prospectively, in the third quarter of 2021. The CIP compares current distribution revenues by customer class to approved target revenues established in ACE's most recent distribution base rate case. The CIP is calculated annually, and recovery is subject to certain conditions, including an earnings test and ceilings on customer rate increases. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

Number of Electric Customers	At March 31,	
	2024	2023
Residential	505,793	503,260
Small commercial & industrial	62,704	62,230
Large commercial & industrial	2,893	3,030
Public authorities & electric railroads	728	726
Total	572,118	569,246

**Distribution Revenue** increased for the three months ended March 31, 2024 compared to the same period in 2023 due to higher distribution rates that became effective December 2023 and the expiration of customer credits related to the TCJA tax benefits.

**Transmission Revenues.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the three months ended March 31, 2024 compared to the same period in 2023, primarily due to increases in underlying costs and capital investment.

**Other Revenue** includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

**Regulatory Required Programs** represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bond Charge, and BGS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as ACE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ACE acts as the billing agent and therefore, ACE does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ACE, ACE is permitted to recover the electricity, ZEC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The decrease of \$8 million for the three months ended March 31, 2024 compared to the same period in 2023, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase	
BSC and PHISCO costs	\$	3
Storm-related costs		2
Other		1
		6
Regulatory required programs <sup>(a)</sup>		—
Total increase	\$	6

(a) ACE is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through the Societal Benefits Charge.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2024	
	Increase	
Depreciation and amortization <sup>(a)</sup>	\$	5
Regulatory asset amortization		2
Regulatory required programs		—
Total increase	\$	7

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

**Interest expense, net** increased \$4 million for the year ended March 31, 2024 compared to the same period in 2023 primarily due to an increase in interest rates and the issuance of debt in 2023 and 2024.

**Effective income tax rates** were 27.5% and 25.0% for the three months ended March 31, 2024 and 2023, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

## **Liquidity and Capital Resources (All Registrants)**

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations, as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each of the Registrants annually evaluates its financing plan, dividend practices, and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, including construction expenditures, retire debt, pay dividends, and fund pension and OPEB obligations. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, the Utility Registrants operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to credit facilities with aggregate bank commitments of \$4.0 billion. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings, and to issue letters of credit. See the "Credit Matters and Cash Requirements" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

### **Cash Flows from Operating Activities**

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE, and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, and their ability to achieve operating cost reductions. Additionally, ComEd is required to purchase CMCs from participating nuclear-powered generating facilities for a five-year period that began in June 2022, and all of its costs of doing so will be recovered through a rider. The price to be paid for each CMC is established through a competitive bidding process. ComEd will provide net payments to, or collect net payments from, customers for the difference between customer credits issued and the credit to be received from the participating nuclear-powered generating facilities. ComEd's cash flows are affected by the establishment of CMC prices and the timing of recovering costs through the CMC regulatory asset.

See Note 3 — Regulatory Matters of the 2023 Form 10-K and Notes 2 — Regulatory Matters and 11 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on regulatory and legal proceedings and proposed legislation.

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The following table provides a summary of the change in cash flows from operating activities for the three months ended March 31, 2024 and 2023 by Registrant:

Increase (decrease) in cash flows from operating activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income (loss)	\$ (11)	\$ (48)	\$ (17)	\$ 64	\$ 13	\$ 10	\$ 6	\$ (4)
Adjustments to reconcile net income to cash:								
Non-cash operating activities	129	115	—	(34)	24	(4)	17	19
Collateral received (paid), net	221	12	—	22	189	24	120	45
Income taxes	(2)	6	(1)	—	4	4	1	(2)
Pension and non-pension postretirement benefit contributions	(67)	18	(2)	(17)	(65)	—	—	(6)
Regulatory assets and liabilities, net	576	653	(35)	31	(69)	9	(28)	(50)
Changes in working capital and other assets and liabilities	(338)	(84)	(72)	(58)	(63)	(38)	(6)	(18)
Increase (decrease) in cash flows from operating activities	\$ 508	\$ 672	\$ (127)	\$ 8	\$ 33	\$ 5	\$ 110	\$ (16)

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. See above for additional information related to cash flows from Generation. Significant operating cash flow impacts for the Registrants and Generation for the three months ended March 31, 2024 and 2023 were as follows:

- See Note 14 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **non-cash operating activities**.
- Changes in **collateral** depended upon whether the Registrant was in a net mark-to-market liability or asset position, and collateral may have been required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differed depending on whether the transactions were on an exchange or in the over-the-counter markets. Changes in collateral for the Registrants are dependent upon the credit exposure of procurement contracts that may require suppliers to post collateral. The change in Collateral received (paid), net, when comparing the three month ended March 31, 2024 to the three month ended March 31, 2023, is due to stable energy prices for the current year. See Note 8 — Derivative Financial Instruments for additional information.
- See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **income taxes**.
- Changes in **Pension and non-pension postretirement benefit contributions** relates to Exelon's increased contributions to the Qualified Plans during the three months ended March 31, 2024. See Note 14 — Retirement Benefits of the 2023 Form 10-K for additional information.
- Changes in **regulatory assets and liabilities, net**, are due to the timing of cash payments for costs recoverable, or cash receipts for costs recovered, under our regulatory mechanisms differs from the recovery period of those costs. Included within the changes is energy efficiency spend for ComEd of \$80 million and \$72 million for the three months ended March 31, 2024 and 2023, respectively. Also included within the changes is energy efficiency and demand response programs spend for BGE, Pepco, DPL and ACE of \$28 million, \$10 million, \$4 million, and \$8 million for the three months ended March 31, 2024 and \$33 million, \$14 million, \$5 million, and \$4 million for the three months ended March 31, 2023, respectively. PECO had no energy efficiency and demand response programs spend recorded to the regulatory asset for the three months ended March 31,

2024 and 2023. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

- **Changes in working capital and other assets and liabilities** for the Utility Registrants and Exelon Corporate totaled \$(276) million and \$(338) million, respectively. The change in working capital and other noncurrent assets and liabilities for Exelon Corporate and the Utility Registrants is dependent upon the normal course of operations for all Registrants. For ComEd, it is also dependent upon whether the participating nuclear-powered generating facilities are owed money from ComEd as a result of the established pricing for CMCs. For the three months ended March 31, 2024, the established pricing resulted in ComEd owing payments to nuclear-powered generating facilities, which is reported within the cash flows from operations as a change in accounts payable and accrued expense.

### Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the three months ended March 31, 2024 and 2023 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	\$ 114	\$ 23	\$ (26)	\$ 26	\$ 108	\$ 35	\$ —	\$ 72
Proceeds from sales of assets and businesses	2	—	—	—	—	—	—	—
Changes in intercompany money pool	—	—	—	—	—	(134)	—	—
Other investing activities	(12)	—	2	5	(8)	(8)	—	—
Increase (decrease) in cash flows from investing activities	\$ 104	\$ 23	\$ (24)	\$ 31	\$ 100	\$ (107)	\$ —	\$ 72

Significant investing cash flow impacts for the Registrants for three months ended March 31, 2024 and 2023 were as follows:

- Changes in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. See the "Credit Matters and Cash Requirements" section below for additional information on projected capital expenditure spending for the Utility Registrants. See Note — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for capital expenditures related to Generation prior to the separation.
- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.

### Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the three months ended March 31, 2024 and 2023 by Registrant:

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(Decrease) increase in cash flows from financing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	\$ 963	\$ 296	\$ (71)	\$ 235	\$ 20	\$ 167	\$ 52	\$ (199)
Long-term debt, net	(1,344)	(975)	—	—	75	25	50	—
Changes in intercompany money pool	—	—	—	—	—	—	—	134
Dividends paid on common stock	(23)	(7)	1	(12)	—	(3)	(3)	(1)
Distributions to member	—	—	—	—	(6)	—	—	—
Contributions from parent/member	—	(147)	250	(237)	82	8	55	18
Other financing activities	6	12	—	—	(4)	(1)	(1)	(1)
(Decrease) increase in cash flows from financing activities	\$ (398)	\$ (821)	\$ 180	\$ (14)	\$ 167	\$ 196	\$ 153	\$ (49)

Significant financing cash flow impacts for the Registrants for the three months ended March 31, 2024 and 2023 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings for the Registrants.
- **Long-term debt, net**, varies due to debt issuances and redemptions each year. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on debt issuances. Refer to the debt redemptions table below for additional information.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer below for more information regarding the intercompany money pool.
- Exelon's ability to pay **dividends** on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. See Note 18 — Commitments and Contingencies of the 2023 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.

### **Debt**

See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt issuances.

During the three months ended March 31, 2024, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	SMBC Term Loan Agreement	SOFR plus 0.85%	April 8, 2024	\$ 500
Exelon	Software Licensing Agreement	3.62 %	December 1, 2025	\$ 1
Pepco	First Mortgage Bonds	3.60 %	March 15, 2024	\$ 400

### **Dividends**

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2024 and for the second quarter of 2024 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share <sup>(a)</sup>
First Quarter 2024	February 21, 2024	March 4, 2024	March 15, 2024	\$ 0.3800
Second Quarter 2024	April 30, 2024	May 13, 2024	June 14, 2024	\$ 0.3800

(a) Exelon's Board of Directors approved an updated dividend policy for 2024. The 2024 quarterly dividend will be \$0.38 per share.

### Credit Matters and Cash Requirements

The Registrants fund liquidity needs for capital investment, working capital, energy hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, and large, diversified credit facilities. The credit facilities include \$4.0 billion in aggregate total commitments of which \$2.7 billion was available to support additional commercial paper as of March 31, 2024, and of which no financial institution has more than 6% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during the three months ended March 31, 2024 to fund their short-term liquidity needs, when necessary. Exelon Corporate and the Utility Registrants each have a 5-year revolving credit facility. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I. ITEM 1A. RISK FACTORS of the 2023 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flows from operating activities, access to credit markets, and their credit facilities provide sufficient liquidity to support the estimated future cash requirements.

On August 4, 2022, Exelon executed an equity distribution agreement (“Equity Distribution Agreement”) with certain sales agents and forward sellers and certain forward purchasers establishing an ATM equity distribution program under which it may offer and sell shares of its common stock, having an aggregate gross sales price of up to \$1.0 billion. Exelon has no obligation to offer or sell any shares of common stock under the Equity Distribution Agreement and may at any time suspend or terminate offers and sales under the Equity Distribution Agreement. As of December 31, 2023, \$858 million of Common stock remained available for sale pursuant to the ATM program. For the period ended March 31, 2024, Exelon did not issue any shares of common stock under the ATM program and did not enter into any forward sale agreements.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at March 31, 2024 and available credit facility capacity prior to any incremental collateral at March 31, 2024:

	PJM Credit Policy Collateral	Other Incremental Collateral Required <sup>(a)</sup>	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ —	\$ —	\$ 660
PECO	—	27	598
BGE	—	47	188
Pepco	—	—	300
DPL	—	12	300
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

### Capital Expenditure Spending

As of March 31, 2024, the most recent estimates of capital expenditures for plant additions and improvements for 2024 are as follows:

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<b>(In millions)</b>	<b>Transmission</b>	<b>Distribution</b>	<b>Gas</b>	<b>Total<sup>(a)</sup></b>
Exelon	N/A	N/A	N/A	\$ 7,425
ComEd	475	1,675	N/A	2,150
PECO	75	1,225	400	1,700
BGE	475	625	500	1,600
PHI	575	1,325	100	1,975
Pepco	225	750	N/A	975
DPL	200	300	100	625
ACE	125	275	N/A	400

(a) Numbers rounded to the nearest \$25M and may not sum due to rounding.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

### **Retirement Benefits**

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 projected contributions reflect a funding strategy to make annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This funding strategy helps minimize volatility of future period required pension contributions. Exelon's estimated annual qualified pension contributions will be \$93 million in 2024. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery).

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

See Note 14 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements of the 2023 Form 10-K for additional information on pension and OPEB contributions.

### **Credit Facilities**

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' credit facilities and short term borrowing activity.

**Security Ratings**

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 8 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for the Registrants did not change for the three months ended March 31, 2024.

**Intercompany Money Pool**

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2024, are presented in the following table:

	During the Three Months Ended March 31, 2024		At March 31, 2024
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
<b>Exelon Intercompany Money Pool</b>			
Exelon Corporate	\$ 626	\$ —	\$ 330
PECO	55	(255)	—
BSC	—	(420)	(302)
PHI Corporate	—	(86)	(73)
PCI	45	—	45

	During the Three Months Ended March 31, 2024		At March 31, 2024
	Maximum Contributed	Maximum Borrowed	(Borrowed) Contributed
<b>PHI Intercompany Money Pool</b>			
Pepco	\$ 171	\$ —	\$ 134
DPL	—	(33)	—
ACE	—	(171)	(134)

**Shelf Registration Statements**

As of January 1st, 2024 Exelon and the Utility Registrants had an effective combined shelf registration statement, unlimited in amount ("Legacy Registration Statement"). On February 20, 2024, Exelon Corporation filed with the SEC Post-Effective Amendment 1 to its Legacy Registration Statement to remove and withdraw registration of all registered securities of ACE, DPL, PECO and BGE.

On February 21, 2024, Exelon Corporation, together with Pepco and ComEd as co-registrants, filed with the SEC Post-Effective Amendment 2 to its Legacy Registration Statement. Post-Effective Amendment 2 amends the Legacy Registration Statement to include an authorized limit of \$7,200 million, which can be used to issue Exelon Corporation debt securities and equity securities, as well as Pepco and ComEd debt securities, through the expiration date of August 3, 2025. On February 21, 2024, PECO and BGE filed with the SEC a standalone effective shelf registration statement, unlimited in amount, which can be used to issue PECO and BGE debt securities through the expiration date of February 20, 2027. The ability of Exelon Corporation, ComEd, Pepco,

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(a) (b)

(c)

(e)

PECO and BGE to sell securities off their corresponding registration Statements, or to access the private placement markets, will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

As a result of Post-Effect Amendment 1, DPL and ACE filed to deregister all securities that remain unsold. DPL and ACE periodically issue securities through the private placement markets. DPL and ACE's ability to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, current financial condition, securities ratings and market conditions.

**Regulatory Authorizations**

The Utility Registrants are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	At March 31, 2024					
	Short-term Financing Authority <sup>(a)</sup>			Remaining Long-term Financing Authority		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd <sup>(a) (b)</sup>	FERC	December 31, 2025	\$ 2,500	ICC	January 1, 2027	\$ 2,368
PECO	FERC	December 31, 2025	1,500	PAPUC	December 31, 2024	550
BGE <sup>(c)</sup>	FERC	December 31, 2025	700	MDPSC	N/A	1,100
Pepco	FERC	December 31, 2025	500	MDPSC / DCPSC	December 31, 2025	375
DPL	FERC	December 31, 2025	500	MDPSC / DEPSC	December 31, 2025	375
ACE	NJBPU	December 31, 2025	350	NJBPU	December 31, 2024	550

- (a) On June 29, 2023, ComEd filed an application for \$2 billion in new money long-term debt financing authority from the ICC and received approval on January 1, 2024.
- (b) On February 20, 2024, ComEd filed an application for \$750 million in refinancing authority from the ICC, which was approved on April 18, 2024. The refinancing authority under the approved application has an effective date of May 1, 2024, and extends the expiration date to May 1, 2027.
- (c) The financing authority filed with MDPSC does not have an expiration date, while the financing authority filed with DCPSC and DEPSC have an expiration date of December 31, 2025.

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Registrants hold commodity and financial instruments that are exposed to the following market risks:

- Commodity price risk, which is discussed further below.
- Counterparty credit risk associated with non-performance by counterparties on executed derivative instruments and participation in all, or some of the established, wholesale spot energy markets that are administered by PJM. The credit policies of PJM may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. See Note 8 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of counterparty credit risk related to derivative instruments.
- Equity price and interest rate risk associated with Exelon's pension and OPEB plan trusts. See Note 7 — Retirement Benefits of the 2023 Form 10-K for additional information.
- Interest rate risk associated with changes in interest rates for the Registrants' outstanding long-term debt. This risk is significantly reduced as substantially all of the Registrants' outstanding debt has fixed interest rates. There is inherent interest rate risk related to refinancing maturing debt by issuing new long-term debt. The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. In addition, Exelon may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges, or to lock in rate levels on borrowings, which are typically designated as economic hedges. See Note 8 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants operate primarily under cost-based rate regulation limiting exposure to the effects of market risk. Hedging programs are utilized to reduce exposure to energy and natural gas price volatility and have no direct earnings impacts as the costs are fully recovered through regulatory-approved recovery mechanisms.

Exelon manages these risks through risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. Risk management issues are reported to Exelon's Executive Committee, the Risk Management Committees of each Utility Registrant, and the Audit and Risk Committee of Exelon's Board of Directors.

#### Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the total amount of energy Exelon purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity and natural gas.

ComEd entered into 20-year floating-to-fixed renewable energy swap contracts beginning in June 2012, which are considered an economic hedge and have changes in fair value recorded to an offsetting regulatory asset or liability. ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. PECO, BGE, Pepco, DPL, and ACE have contracts to procure electric supply that are executed through a competitive procurement process. PECO, BGE, Pepco, DPL, and ACE have certain full requirements contracts, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE, and DPL also have executed derivative natural gas contracts, which qualify for NPNS, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their financial statements.

For additional information on these contracts, see Note 8 — Derivative Financial Instruments and Note 10 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements.

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The following table presents the maturity and source of fair value for Exelon's and ComEd's mark-to-market commodity contract net liabilities. These net liabilities are associated with ComEd's floating-to-fixed energy swap contracts with unaffiliated suppliers. The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of Exelon's and ComEd's total mark-to-market net liabilities. Second, the table shows the maturity, by year, of Exelon's and ComEd's commodity contract net liabilities giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 10 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Commodity derivative contracts <sup>(a)</sup> :	Maturities Within					2029 and Beyond	Total Fair Value
	2024	2025	2026	2027	2028		
Prices based on model or other valuation methods (Level 3)	\$ (24)	\$ (17)	\$ (14)	\$ (14)	\$ (14)	\$ (25)	\$ (108)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

### ITEM 4. CONTROLS AND PROCEDURES

During the first quarter of 2024, each of the Registrants' management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by the Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to that Registrant's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of March 31, 2024, the principal executive officer and principal financial officer of each of the Registrants concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. In the first quarter of 2024, ComEd and PECO implemented a new customer care and billing information system replacing the existing system. ComEd and PECO expect the new system to further automate, enhance and standardize the processes by which they engage with their customers. As part of this system implementation, ComEd and PECO appropriately considered the impacts to internal controls over financial reporting. There were no other changes in internal control over financial reporting that occurred during the three months ended March 31, 2024, that have materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting.

## PART II — OTHER INFORMATION

### ITEM 1. LEGAL PROCEEDINGS

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of the 2023 Form 10-K, (b) Notes 3 — Regulatory Matters and 18 — Commitments and Contingencies of the 2023 Form 10-K, and (c) Notes 2 — Regulatory Matters and 11 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

### ITEM 1A. RISK FACTORS

#### Risks Related to All Registrants

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At March 31, 2024, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2023 Form 10-K in ITEM 1A. RISK FACTORS.

**ITEM 5. OTHER INFORMATION**

**All Registrants**

None.

**ITEM 6. EXHIBITS**

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable Registrant and its subsidiaries on a consolidated basis and the relevant. Registrant agrees to furnish a copy of any such instrument to the Commission upon request.

**(4) Instruments Defining the Rights of Securities Holders, Including Indentures**

Exelon Corporation

Exhibit No.	Description	Location
<a href="#">4-1</a>	Seventh Supplemental Indenture, dated as of February 27, 2024, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	<a href="#">File No. 001-16169, Form 8-K dated February 27, 2024, Exhibit 4.2</a>

Potomac Electric Power Company

Exhibit No.	Description	Location
<a href="#">4-2</a>	Pepco Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 15, 2024	<a href="#">File No. 001-01072, Form 8-K dated March 4, 2024, Exhibit 4.3</a>

Atlantic City Electric Company

Exhibit No.	Description	Location
<a href="#">4-3</a>	ACE Supplemental Indenture to the Mortgage and Deed of Trust, dated as of March 1, 2024	<a href="#">File No. 001-03559, Form 8-K dated March 20, 2024, Exhibit 4.2</a>

Delmarva Power & Light Company

<a href="#">4-4</a>	DPL Supplemental Indenture to the Mortgage and Deed of Trust, dated as of March 1, 2024	<a href="#">File No. 001-01405, Form 8-K dated March 20, 2024, Exhibit 4.4</a>
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**(10) Material Contracts**

Exelon Corporation

Exhibit No.	Description	Location
<a href="#">10-1</a>	Exelon Corporation Senior Management Severance Plan, as amended and restated effective February 1, 2024.	<a href="#">Filed herewithin.</a>
<a href="#">10-2</a>	Exelon Corporation Long-Term Incentive Program, as amended and restated effective February 1, 2024.	<a href="#">Filed herewithin.</a>

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Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2024 filed by the following officers for the following companies:

### Exelon Corporation

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-1</a>	<a href="#">Filed by Calvin G. Butler, Jr. for Exelon Corporation</a>
<a href="#">31-2</a>	<a href="#">Filed by Jeanne M. Jones for Exelon Corporation</a>

### Commonwealth Edison Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-3</a>	<a href="#">Filed by Gil C. Quiniones for Commonwealth Edison Company</a>
<a href="#">31-4</a>	<a href="#">Filed by Joshua S. Levin for Commonwealth Edison Company</a>

### PECO Energy Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-5</a>	<a href="#">Filed by Michael A. Innocenzo for PECO Energy Company</a>
<a href="#">31-6</a>	<a href="#">Filed by Marissa Humphrey for PECO Energy Company</a>

### Baltimore Gas and Electric Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-7</a>	<a href="#">Filed by Carim V. Khouzami for Baltimore Gas and Electric Company</a>
<a href="#">31-8</a>	<a href="#">Filed by David M. Vahos for Baltimore Gas and Electric Company</a>

### Pepco Holdings LLC

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-9</a>	<a href="#">Filed by J. Tyler Anthony for Pepco Holdings LLC</a>
<a href="#">31-10</a>	<a href="#">Filed by Phillip S. Barnett for Pepco Holdings LLC</a>

### Potomac Electric Power Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-11</a>	<a href="#">Filed by J. Tyler Anthony for Potomac Electric Power Company</a>
<a href="#">31-12</a>	<a href="#">Filed by Phillip S. Barnett for Potomac Electric Power Company</a>

### Delmarva Power & Light Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-13</a>	<a href="#">Filed by J. Tyler Anthony for Delmarva Power &amp; Light Company</a>
<a href="#">31-14</a>	<a href="#">Filed by Phillip S. Barnett for Delmarva Power &amp; Light Company</a>

### Atlantic City Electric Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">31-15</a>	<a href="#">Filed by J. Tyler Anthony for Atlantic City Electric Company</a>
<a href="#">31-16</a>	<a href="#">Filed by Phillip S. Barnett for Atlantic City Electric Company</a>

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes-Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2024 filed by the following officers for the following companies:

## [Table of Contents](#)

### Exelon Corporation

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-1</a>	<a href="#">Filed by Calvin G. Butler, Jr. for Exelon Corporation</a>
<a href="#">32-2</a>	<a href="#">Filed by Jeanne M. Jones for Exelon Corporation</a>

### Commonwealth Edison Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-3</a>	<a href="#">Filed by Gil C. Quiniones for Commonwealth Edison Company</a>
<a href="#">32-4</a>	<a href="#">Filed by Joshua S. Levin for Commonwealth Edison Company</a>

### PECO Energy Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-5</a>	<a href="#">Filed by Michael A. Innocenzo for PECO Energy Company</a>
<a href="#">32-6</a>	<a href="#">Filed by Marissa Humphrey for PECO Energy Company</a>

### Baltimore Gas and Electric Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-7</a>	<a href="#">Filed by Carim V. Khouzami for Baltimore Gas and Electric Company</a>
<a href="#">32-8</a>	<a href="#">Filed by David M. Vahos for Baltimore Gas and Electric Company</a>

### Pepco Holdings LLC

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-9</a>	<a href="#">Filed by J. Tyler Anthony for Pepco Holdings LLC</a>
<a href="#">32-10</a>	<a href="#">Filed by Phillip S. Barnett for Pepco Holdings LLC</a>

### Potomac Electric Power Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-11</a>	<a href="#">Filed by J. Tyler Anthony for Potomac Electric Power Company</a>
<a href="#">32-12</a>	<a href="#">Filed by Phillip S. Barnett for Potomac Electric Power Company</a>

### Delmarva Power & Light Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-13</a>	<a href="#">Filed by J. Tyler Anthony for Delmarva Power &amp; Light Company</a>
<a href="#">32-14</a>	<a href="#">Filed by Phillip S. Barnett for Delmarva Power &amp; Light Company</a>

### Atlantic City Electric Company

<b>Exhibit No.</b>	<b>Description</b>
<a href="#">32-15</a>	<a href="#">Filed by J. Tyler Anthony for Atlantic City Electric Company</a>
<a href="#">32-16</a>	<a href="#">Filed by Phillip S. Barnett for Atlantic City Electric Company</a>

101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)







Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**PECO ENERGY COMPANY**

/s/ MICHAEL A. INNOCENZO

Michael A. Innocenzo  
President, Chief Executive Officer (Principal Executive Officer) and  
Director

/s/ CAROLINE FULGINITI

Caroline Fulginiti  
Director, Accounting  
(Principal Accounting Officer)

/s/ MARISSA HUMPHREY

Marissa Humphrey  
Senior Vice President, Chief Financial Officer and Treasurer  
(Principal Financial Officer)

May 2, 2024

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**BALTIMORE GAS AND ELECTRIC COMPANY**

/s/ CARIM V. KHOUZAMI

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Carim V. Khouzami  
President, Chief Executive Officer  
(Principal Executive Officer) and Director

/s/ JASON T. JONES

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Jason T. Jones  
Director, Accounting  
(Principal Accounting Officer)

/s/ DAVID M. VAHOS

---

David M. Vahos  
Senior Vice President, Chief Financial Officer and Treasurer  
(Principal Financial Officer)

May 2, 2024

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**PEPCO HOLDINGS LLC**

/s/ J. TYLER ANTHONY

J. Tyler Anthony  
President, Chief Executive Officer  
(Principal Executive Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese  
Director, Accounting  
(Principal Accounting Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett  
Senior Vice President, Chief Financial Officer and Treasurer  
(Principal Financial Officer)

May 2, 2024

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**POTOMAC ELECTRIC POWER COMPANY**

/s/ J. TYLER ANTHONY

J. Tyler Anthony  
President, Chief Executive Officer  
(Principal Executive Officer) and Director

/s/ PHILLIP S. BARNETT

Phillip S. Barnett  
Senior Vice President, Chief Financial Officer, Treasurer  
(Principal Financial Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese  
Director, Accounting  
(Principal Accounting Officer)

May 2, 2024

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**DELMARVA POWER & LIGHT COMPANY**

/s/ J. TYLER ANTHONY

J. Tyler Anthony  
President, Chief Executive Officer  
(Principal Executive Officer) and Director

/s/ PHILLIP S. BARNETT

Phillip S. Barnett  
Senior Vice President, Chief Financial Officer and Treasurer  
(Principal Financial Officer)

/s/ JULIE E. GIESE

Julie E. Giese  
Director, Accounting  
(Principal Accounting Officer)

May 2, 2024

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**ATLANTIC CITY ELECTRIC COMPANY**

/s/ J. TYLER ANTHONY

J. Tyler Anthony  
President, Chief Executive Officer  
(Principal Executive Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese  
Director, Accounting  
(Principal Accounting Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett  
Senior Vice President, Chief Financial Officer and Treasurer  
(Principal Financial Officer)

May 2, 2024

BEFORE THE  
PUBLIC SERVICE COMMISSION  
OF MARYLAND

AFFIDAVIT OF  
JULIE E. GIESE

I, Julie E. Giese, am the Director, Accounting (Principal Accounting Officer) 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 to the best of my knowledge, information and belief, Delmarva and Pepco in good faith follow the processes and procedures set forth in the Pepco Holdings LLC Cost Allocation Manual (CAM) as well as the Commission's Asset Transfer policies contained in the Code of Maryland Regulations (COMAR) 20.40.02.05.

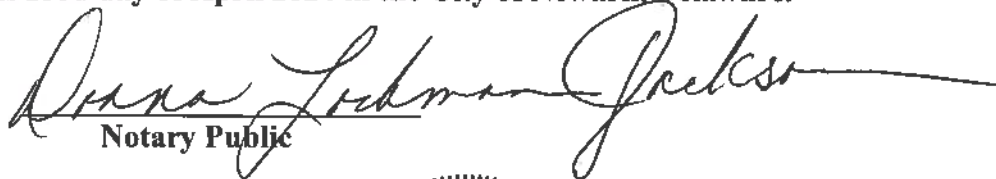
  
Julie E. Giese

April 23, 2024

Date

City of Newark )  
State of Delaware )

Subscribed and sworn to me this 23rd day of April 2024 in the City of Newark, Delaware.

  
Notary Public

My Commission expires 03-10-2028

