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 quarter ended June 30, 2014

Commission File Number	Exact Name of Registrant as specified in its Charter, State or Other Jurisdiction of Incorporation, Address of Principal Executive Offices, Zip Code and Telephone Number (Including Area Code)	I.R.S. Employer Identification Number
001-31403	**PEPCO HOLDINGS, INC.** (Pepco Holdings or PHI), a Delaware corporation 701 Ninth Street, N.W. Washington, D.C. 20068 Telephone: (202)872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** (Pepco), a District of Columbia and Virginia corporation 701 Ninth Street, N.W. Washington, D.C. 20068 Telephone: (202)872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** (DPL), a Delaware and Virginia corporation 500 North Wakefield Drive Newark, DE 19702 Telephone: (202)872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** (ACE), a New Jersey corporation 500 North Wakefield Drive Newark, DE 19702 Telephone: (202)872-2000	21-0398280

Indicate by check mark whether each 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 and (2) has been subject to such filing requirements for the past 90 days.

Pepco Holdings	Yes ☒	No ☐	Pepco	Yes ☒	No ☐
DPL	Yes ☒	No ☐	ACE	Yes ☒	No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Pepco Holdings	Yes ☒	No ☐	Pepco	Yes ☒	No ☐
DPL	Yes ☒	No ☐	ACE	Yes ☒	No ☐

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

	Large Accelerated Filer	**Accelerated Filer**	**Non-Accelerated Filer**	**Smaller Reporting Company**
Pepco Holdings	☒	☐	☐	☐
Pepco	☐	☐	☒	☐
DPL	☐	☐	☒	☐
ACE	☐	☐	☒	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Pepco Holdings	Yes ☐	No ☒	Pepco	Yes ☐	No ☒
DPL	Yes ☐	No ☒	ACE	Yes ☐	No ☒

Pepco, DPL, and ACE meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with reduced disclosure format specified in General Instruction H(2) of Form 10-Q.

Registrant	**Number of Shares of Common Stock of the Registrant Outstanding at July 21, 2014**
Pepco Holdings	251,524,386 ($.01 par value)
Pepco	100 ($.01 par value) (a)
DPL	1,000 ($2.25 par value) (b)
ACE	8,546,017 ($3.00 par value) (b)

(a) All voting and non-voting common equity is owned by Pepco Holdings.
(b) All voting and non-voting common equity is owned by Conectiv, LLC, a wholly owned subsidiary of Pepco Holdings.

THIS COMBINED FORM 10-Q IS SEPARATELY FILED BY PEPCO HOLDINGS, PEPCO, DPL, AND ACE. INFORMATION CONTAINED HEREIN RELATING TO ANY INDIVIDUAL REGISTRANT IS FILED BY SUCH REGISTRANT ON ITS OWN BEHALF. EACH REGISTRANT MAKES NO REPRESENTATION AS TO INFORMATION RELATING TO THE OTHER REGISTRANTS.

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GLOSSARY OF TERMS

Term	Definition
2013 Form 10-K	The Annual Report on Form 10-K for the year ended December 31, 2013, for each Reporting Company, as applicable
ACE	Atlantic City Electric Company
ACE Funding	Atlantic City Electric Transition Funding LLC
AFUDC	Allowance for funds used during construction
AMI	Advanced metering infrastructure
AOCL	Accumulated Other Comprehensive Loss
ASC	Accounting Standards Codification
BGE	Baltimore Gas and Electric Company
BGS	Basic Generation Service (the supply of electricity by ACE to retail customers in New Jersey who have not elected to purchase electricity from a competitive supplier)
Bondable Transition Property	The principal and interest payments on the Transition Bonds and related taxes, expenses and fees
BSA	Bill Stabilization Adjustment
Calpine	Calpine Corporation, the purchaser of the Conectiv Energy wholesale power generation business
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
Consent	Amendment and Consent to Second Amended and Restated Credit Agreement dated May 20, 2014, entered into by PHI, Pepco, DPL, and ACE
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MPSC to enter into a contract for new generation
CSA	Credit Support Annex
CTA	Consolidated tax adjustment
DC Undergrounding Task Force	The District of Columbia Mayor’s Power Line Undergrounding Task Force
DCPSC	District of Columbia Public Service Commission
DC PLUG	District of Columbia Power Line Undergrounding
DDOE	District of Columbia Department of the Environment
Default Electricity Supply	The supply of electricity by PHI’s electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
Default Electricity Supply Revenue	Revenue primarily from Default Electricity Supply
DEMEC	Delaware Municipal Electric Corporation, Inc.
DOE	U.S. Department of Energy
DPL	Delmarva Power & Light Company
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSEU	Delaware Sustainable Energy Utility
EDCs	Electric distribution companies
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
EPA	U.S Environmental Protection Agency
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934, as amended
Exelon	Exelon Corporation, a Pennsylvania corporation
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FLRP	Forward Looking Rate Plan filed by DPL in Delaware
GAAP	Accounting principles generally accepted in the United States of America
GCR	Gas Cost Rate
GWh	Gigawatt hour
IMU	Interface management unit
IRS	Internal Revenue Service

Term	Definition
ISDA	International Swaps and Derivatives Association
ISRA	New Jersey's Industrial Site Recovery Act
LIBOR	London Interbank Offered Rate
MAPP	Mid-Atlantic Power Pathway
MDC	MDC Industries, Inc.
Merger	Merger of Merger Sub with and into PHI
Merger Agreement	Agreement and Plan of Merger, dated April 29, 2014 among Exelon, Merger Sub and PHI, as amended and restated on July 18, 2014
MFVRD	Modified fixed variable rate design
MMBtu	One Million British Thermal units
MPSC	Maryland Public Service Commission
MW	Megawatt
New Jersey Societal Benefit Program	A New Jersey statewide public interest program that is intended to benefit low income customers and address other public policy goals
NJBPU	New Jersey Board of Public Utilities
NJ SOCA Law	The New Jersey law under which the SOCAs were established
NOAA	National Oceanic and Atmospheric Administration
NUGs	Non-utility generators
OPC	Office of People's Counsel
OPEB	Other postretirement benefit
PCI	Potomac Capital Investment Corporation and its subsidiaries
Pepco	Potomac Electric Power Company
Pepco Energy Services	Pepco Energy Services, Inc. and its subsidiaries
Pepco Holdings or PHI	Pepco Holdings, Inc.
PHI Retirement Plan	PHI's noncontributory retirement plan
PJM	PJM Interconnection, LLC
PJM RTO	PJM regional transmission organization
Power Delivery	PHI's Power Delivery Business
PPA	Power purchase agreement
Preferred Stock	PHI issued to Exelon originally issued shares of non-voting, non-convertible and non-transferable preferred stock, par value $0.01 per share
PRP	Potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
RECs	Renewable energy credits
Regulated T&D Electric Revenue	Revenue from the transmission and the distribution of electricity to PHI's customers within its service territories at regulated rates
Reporting Company	PHI, Pepco, DPL or ACE
RI/FS	Remedial investigation and feasibility study
ROE	Return on equity
RPS	Renewable Energy Portfolio Standards
SEC	Securities and Exchange Commission
SEP	Supplemental Environmental Project
SOCAs	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
SOS	Standard Offer Service, how Default Electricity Supply is referred to in Delaware, the District of Columbia and Maryland
SRECs	Solar renewable energy credits
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees

Term	Definition
Transition Bonds	Transition Bonds issued by ACE Funding
VIE	Variable interest entity
VSCC	Virginia State Corporation Commission

FORWARD-LOOKING STATEMENTS

Some of the statements contained in this Quarterly Report on Form 10-Q with respect to Pepco Holdings, Inc. (PHI or Pepco Holdings), Potomac Electric Power Company (Pepco), Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE), including each of their respective subsidiaries, are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act), and Section 27A of the Securities Act of 1933, as amended, and are subject to the safe harbor created thereby under the Private Securities Litigation Reform Act of 1995. These statements include declarations regarding the intents, beliefs, estimates and current expectations of one or more of PHI, Pepco, DPL or ACE (each, a Reporting Company) or their subsidiaries. In some cases, you can identify forward-looking statements by terminology such as "may," "might," "will," "should," "could," "expects," "intends," "assumes," "seeks to," "plans," "anticipates," "believes," "projects," "estimates," "predicts," "potential," "future," "goal," "objective," or "continue" or the negative of such terms or other variations thereof or comparable terminology, or by discussions of strategy that involve risks and uncertainties. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause one or more Reporting Companies' or their subsidiaries' actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by such forward-looking statements. Therefore, forward-looking statements are not guarantees or assurances of future performance, and actual results could differ materially from those indicated by the forward-looking statements.

The forward-looking statements contained herein are qualified in their entirety by reference to the following important factors, which are difficult to predict, contain uncertainties, are beyond each Reporting Company's or its subsidiaries' control and may cause actual results to differ materially from those contained in forward-looking statements:

- Certain risks and uncertainties associated with the proposed merger (the Merger) of an indirect, wholly-owned subsidiary of Exelon Corporation, a Pennsylvania corporation (Exelon) with and into Pepco Holdings, including, without limitation:
  - The inability of Pepco Holdings to obtain stockholder approval required for the Merger;
  - The inability of Pepco Holdings or Exelon to obtain regulatory approvals required for the Merger;
  - Delays caused by required regulatory approvals, which may delay the Merger or cause the companies to abandon the Merger;
  - The inability of Pepco Holdings or Exelon to satisfy conditions to the closing of the Merger;
  - An unsolicited offer of another company to acquire assets or capital stock of Pepco Holdings, which could interfere with the Merger;
  - Unexpected costs, liabilities or delays that may arise from the Merger, including as a result of stockholder litigation;
  - Negative impacts on the businesses of Pepco Holdings and its utility subsidiaries as a result of uncertainty surrounding the Merger; and
  - Future regulatory or legislative actions impacting the industries in which Pepco Holdings and its subsidiaries operate, which actions could adversely affect Pepco Holdings and its utility subsidiaries.
- Changes in governmental policies and regulatory actions affecting the energy industry or one or more of the Reporting Companies specifically, including allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of transmission and distribution facilities and the recovery of purchased power expenses;
- The outcome of pending and future rate cases and other regulatory proceedings, including (i) challenges to the base return on equity (ROE) and the application of the formula rate process

previously established by the Federal Energy Regulatory Commission (FERC) for transmission services provided by Pepco, DPL and ACE; (ii) challenges to DPL's 2011, 2012 and 2013 annual FERC formula rate updates; and (iii) other possible disallowances related to recovery of costs (including capital costs and advanced metering infrastructure (AMI) costs) and expenses or delays in the recovery of such costs;

- The resolution of outstanding tax matters with the Internal Revenue Service (IRS), and the funding of any additional taxes, interest or penalties that may be due;
- The expenditures necessary to comply with regulatory requirements, including regulatory orders, and to implement reliability enhancement, emergency response and customer service improvement programs;
- Possible fines, penalties or other sanctions assessed by regulatory authorities against a Reporting Company or its subsidiaries;
- The impact of adverse publicity and media exposure which could render one or more Reporting Companies or their subsidiaries vulnerable to negative customer perception and could lead to increased regulatory oversight or other sanctions;
- Weather conditions affecting usage and emergency restoration costs;
- Population growth rates and changes in demographic patterns;
- Changes in customer energy demand due to, among other things, conservation measures and the use of renewable energy and other energy-efficient products, as well as the impact of net metering and other issues associated with the deployment of distributed generation and other new technologies;
- General economic conditions, including the impact on energy use caused by an economic downturn or recession, or by changes in the level of commercial activity in a particular region or service territory, or affecting a particular business or industry located therein;
- Changes in and compliance with environmental and safety laws and policies;
- Changes in tax rates or policies;
- Changes in rates of inflation;
- Changes in accounting standards or practices;
- Unanticipated changes in operating expenses and capital expenditures;
- Rules and regulations imposed by, and decisions of, federal and/or state regulatory commissions, PJM Interconnection, LLC (PJM), the North American Electric Reliability Corporation (NERC) and other applicable electric reliability organizations;
- Legal and administrative proceedings (whether civil or criminal) and settlements that affect a Reporting Company's or its subsidiaries' business and profitability;
- Pace of entry into new markets;
- Interest rate fluctuations and the impact of credit and capital market conditions on the ability to obtain funding on favorable terms; and
- Effects of geopolitical and other events, including the threat of terrorism or cyber attacks.

These forward-looking statements are also qualified by, and should be read together with, the risk factors and other statements in each Reporting Company's Annual Report on Form 10-K for the year ended December 31, 2013 (2013 Form 10-K), as filed with the Securities and Exchange Commission (SEC), and in this Form 10-Q, and investors should refer to such risk factors and other statements in evaluating the forward-looking statements contained in this Quarterly Report on Form 10-Q.

Any forward-looking statements speak only as to the date this Quarterly Report on Form 10-Q for each Reporting Company was filed with the SEC and none of the Reporting Companies undertakes an obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for a Reporting Company to predict all such factors. Furthermore, it may not be possible to assess the impact of any such factor on such Reporting Company's or its subsidiaries' business (viewed independently or together with the business or businesses of some or all of the other Reporting Companies or their subsidiaries), or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. The foregoing factors should not be construed as exhaustive.

PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Listed below is a table that sets forth, for each registrant, the page number where the information is contained herein.

* Pepco and DPL have no operating subsidiaries and, therefore, their financial statements are not consolidated.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars, except per share data)			
Operating Revenue	$ 1,117	$ 1,051	$ 2,447	$ 2,231
Operating Expenses				
Fuel and purchased energy	463	446	1,077	1,008
Other services cost of sales	61	35	107	75
Other operation and maintenance	221	212	437	439
Depreciation and amortization	132	116	265	228
Other taxes	102	101	206	206
Deferred electric service costs	(13)	(4)	31	(3)
Total Operating Expenses	966	906	2,123	1,953
Operating Income	151	145	324	278
Other Income (Expenses)				
Interest and dividend income	1	—	1	—
Interest expense	(67)	(70)	(132)	(137)
Other income	13	8	26	16
Total Other Expenses	(53)	(62)	(105)	(121)
Income from Continuing Operations Before Income Tax Expense	98	83	219	157
Income Tax Expense Related to Continuing Operations	45	30	91	215
Net Income (Loss) from Continuing Operations	53	53	128	(58)
Loss from Discontinued Operations, net of Income Taxes	—	(11)	—	(330)
Net Income (Loss)	$ 53	$ 42	$ 128	$ (388)
Basic and Diluted Share Information				
Weighted average shares outstanding – Basic (millions)	251	249	251	243
Weighted average shares outstanding – Diluted (millions)	252	249	251	243
Earnings (loss) per share of common stock from Continuing Operations – Basic and Diluted	$ 0.21	$ 0.21	$ 0.51	$ (0.24)
Earnings (loss) per share of common stock from Discontinued Operations – Basic and Diluted	—	(0.04)	—	(1.36)
Basic and Diluted earnings (loss) per share	$ 0.21	$ 0.17	$ 0.51	$ (1.60)

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Net Income (Loss)	$ 53	$ 42	$ 128	$ (388)
Other Comprehensive (Loss) Income from Continuing Operations				
Losses on treasury rate locks reclassified into income	—	1	—	1
Pension and other postretirement benefit plans	(3)	(1)	(2)	1
Other comprehensive (loss) income, before income taxes	(3)	—	(2)	2
Income tax (benefit) expense related to other comprehensive income	(1)	—	(1)	1
Other comprehensive (loss) income from continuing operations, net of income taxes	(2)	—	(1)	1
Other Comprehensive Income from Discontinued Operations, Net of Income Taxes	—	1	—	6
Comprehensive Income (Loss)	$ 51	$ 43	$ 127	$ (381)

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 184	$ 23
Restricted cash equivalents	21	13
Accounts receivable, less allowance for uncollectible accounts of $44 million and $38 million, respectively	822	835
Inventories	149	148
Deferred income tax assets, net	50	51
Income taxes and related accrued interest receivable	8	274
Prepaid expenses and other	82	54
Total Current Assets	1,316	1,398
OTHER ASSETS		
Goodwill	1,407	1,407
Regulatory assets	2,002	2,087
Income taxes and related accrued interest receivable	58	75
Restricted cash equivalents	14	14
Other	168	163
Total Other Assets	3,649	3,746
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	15,043	14,567
Accumulated depreciation	(4,938)	(4,863)
Net Property, Plant and Equipment	10,105	9,704
TOTAL ASSETS	$ 15,070	$ 14,848

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 479	$ 565
Current portion of long-term debt and project funding	371	446
Accounts payable	170	215
Accrued liabilities	327	301
Capital lease obligations due within one year	10	9
Taxes accrued	51	56
Interest accrued	49	47
Liabilities and accrued interest related to uncertain tax positions	6	397
Other	304	277
Total Current Liabilities	1,767	2,313
DEFERRED CREDITS		
Regulatory liabilities	394	399
Deferred income tax liabilities, net	3,160	2,928
Investment tax credits	17	17
Pension benefit obligation	124	116
Other postretirement benefit obligations	173	206
Liabilities and accrued interest related to uncertain tax positions	6	28
Other	187	189
Total Deferred Credits	4,061	3,883
OTHER LONG-TERM LIABILITIES		
Long-term debt	4,557	4,053
Transition bonds issued by ACE Funding	193	214
Long-term project funding	9	10
Capital lease obligations	55	60
Total Other Long-Term Liabilities	4,814	4,337
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
PREFERRED STOCK		
Series A preferred stock, $.01 par value, 18,000 shares authorized, 9,000 and zero shares outstanding, respectively	93	—
EQUITY		
Common stock, $.01 par value, 400,000,000 shares authorized, 251,498,408 and 250,324,898 shares outstanding, respectively	3	3
Premium on stock and other capital contributions	3,780	3,751
Accumulated other comprehensive loss	(35)	(34)
Retained earnings	587	595
Total Equity	4,335	4,315
TOTAL LIABILITIES AND EQUITY	$ 15,070	$ 14,848

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income (loss)	$ 128	$ (388)
Loss from discontinued operations	—	330
Adjustments to reconcile net income (loss) to net cash from operating activities:		
Depreciation and amortization	265	228
Deferred income taxes	225	(451)
Gains on sales of land	(8)	—
Other	(7)	(5)
Changes in:		
Accounts receivable	8	(8)
Inventories	(1)	(8)
Prepaid expenses	(26)	(11)
Regulatory assets and liabilities, net	(51)	(68)
Accounts payable and accrued liabilities	(5)	(50)
Pension contributions	—	(120)
Pension benefit obligation, excluding contributions	23	32
Cash collateral related to derivative activities	(5)	26
Income tax-related prepayments, receivables and payables	(135)	614
Advanced payment made to taxing authority	—	(242)
Interest accrued	3	—
Other assets and liabilities	5	22
Net current assets held for disposition or sale	—	52
Net Cash From (Used by) Operating Activities	419	(47)
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(553)	(616)
Department of Energy capital reimbursement awards received	4	12
Proceeds from sale of land	8	—
Changes in restricted cash equivalents	(8)	(8)
Net other investing activities	3	2
Proceeds from discontinued operations, early termination of finance leases held in trust	—	693
Net Cash (Used By) From Investing Activities	(546)	83
FINANCING ACTIVITIES		
Dividends paid on common stock	(136)	(134)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	26	27
Issuances of common stock	—	324
Issuance of Series A preferred stock	90	—
Issuances of long-term debt	608	350
Reacquisitions of long-term debt	(206)	(19)
Repayments of short-term debt, net	(86)	(373)
Issuance of term loan	—	250
Repayment of term loans	—	(450)
Cost of issuances	(8)	(16)
Net other financing activities	—	(5)
Net Cash From (Used By) Financing Activities	288	(46)
Net Increase (Decrease) in Cash and Cash Equivalents	161	(10)
Cash and Cash Equivalents at Beginning of Period	23	25
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 184	$ 15
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash (received) paid for income taxes, net	$ (2)	$ 227

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Accumulated Other Comprehensive Loss	Retained Earnings	Total
BALANCE, DECEMBER 31, 2013	250,324,898	$ 3	$ 3,751	$ (34)	$ 595	$4,315
Net income	—	—	—	—	75	75
Other comprehensive income	—	—	—	1	—	1
Dividends on common stock ($0.27 per share)	—	—	—	—	(68)	(68)
Issuance of common stock:						
Original issue shares, net	284,022	—	3	—	—	3
Shareholder DRP original issue shares	374,003	—	8	—	—	8
Net activity related to stock-based awards	—	—	2	—	—	2
BALANCE, MARCH 31, 2014	250,982,923	3	3,764	(33)	602	4,336
Net income	—	—	—	—	53	53
Other comprehensive loss	—	—	—	(2)	—	(2)
Dividends on common stock ($0.27 per share)	—	—	—	—	(68)	(68)
Issuance of common stock:						
Original issue shares, net	252,240	—	4	—	—	4
Shareholder DRP original issue shares	263,245	—	7	—	—	7
Net activity related to stock-based awards	—	—	5	—	—	5
BALANCE, JUNE 30, 2014	251,498,408	$ 3	$ 3,780	$ (35)	$ 587	$4,335

The accompanying Notes are an integral part of these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PEPCO HOLDINGS, INC.

(1) ORGANIZATION

Pepco Holdings, Inc. (PHI or Pepco Holdings), a Delaware corporation incorporated in 2001, is a holding company that, through the following regulated public utility subsidiaries, is engaged primarily in the transmission, distribution and default supply of electricity and, to a lesser extent, the distribution and supply of natural gas (Power Delivery):

- Potomac Electric Power Company (Pepco), which was incorporated in Washington, D.C. in 1896 and became a domestic Virginia corporation in 1949,
- Delmarva Power & Light Company (DPL), which was incorporated in Delaware in 1909 and became a domestic Virginia corporation in 1979, and
- Atlantic City Electric Company (ACE), which was incorporated in New Jersey in 1924.

Each of PHI, Pepco, DPL and ACE is also a reporting company under the Securities Exchange Act of 1934, as amended. Together, Pepco, DPL and ACE constitute the Power Delivery segment for financial reporting purposes.

Through Pepco Energy Services, Inc. and its subsidiaries (collectively, Pepco Energy Services), PHI provides energy savings performance contracting services, underground transmission and distribution construction and maintenance services, and steam and chilled water under long-term contracts.

PHI Service Company, a subsidiary service company of PHI, provides a variety of support services, including legal, accounting, treasury, tax, purchasing and information technology services to PHI and its operating subsidiaries. These services are provided pursuant to service agreements among PHI, PHI Service Company and the participating operating subsidiaries. The expenses of PHI Service Company are charged to PHI and the participating operating subsidiaries in accordance with cost allocation methodologies set forth in the service agreements.

Merger with Exelon Corporation

PHI has entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly-owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly-owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly-owned subsidiary of Exelon and shares owned by PHI or any direct or indirect, wholly-owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, as further described in Note (12), "Preferred Stock," PHI entered into a Subscription Agreement with Exelon dated April 29, 2014 (the Subscription Agreement), pursuant to which PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million on April 30, 2014. Exelon also committed, pursuant to the Subscription Agreement, to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on July 29, 2014, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission, the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976; and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). For additional discussion, see Note (7), "Regulatory Matters – Merger Approval Proceedings." The parties currently anticipate that the closing will occur in the second or third quarter of 2015.

The Merger Agreement may be terminated by each of PHI and Exelon under certain circumstances, including if the Merger is not consummated by July 29, 2015 (subject to extension to October 29, 2015, if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for both PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding preferred stock at par value. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Power Delivery

Each of Pepco, DPL and ACE is a regulated public utility in the jurisdictions that comprise its service territory. Each utility owns and operates a network of wires, substations and other equipment that is classified as transmission facilities, distribution facilities or common facilities (which are used for both transmission and distribution). Transmission facilities are high-voltage systems that carry wholesale electricity into, or across, the utility's service territory. Distribution facilities are low-voltage systems that carry electricity to end-use customers in the utility's service territory.

Each utility is responsible for the distribution of electricity, and in the case of DPL, the distribution and supply of natural gas, in its service territory, for which it is paid tariff rates established by the applicable local public service commissions. Each utility also supplies electricity at regulated rates to retail customers in its service territory who do not elect to purchase electricity from a competitive energy supplier. The regulatory term for this supply service is Standard Offer Service (SOS) in Delaware, the District of Columbia and Maryland, and Basic Generation Service in New Jersey. In these Notes to the consolidated financial statements, these supply service obligations are referred to generally as Default Electricity Supply.

Pepco Energy Services

Pepco Energy Services is engaged in the following businesses:

- Energy savings performance contracting business: designing, constructing and operating energy efficiency projects and distributed generation equipment, including combined heat and power plants, principally for federal, state and local government customers;
- Underground transmission and distribution business: providing underground transmission and distribution construction and maintenance services for electric utilities in North America; and
- Thermal business: providing steam and chilled water under long-term contracts through systems owned and operated by Pepco Energy Services, primarily to hotels and casinos in Atlantic City, New Jersey.

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. Pepco Energy Services has determined that it will pursue the demolition of the Benning Road generation facility and realize the scrap metal salvage value of the facility. The demolition of the facility commenced in the fourth quarter of 2013 and is expected to be completed in the first quarter of 2015. Pepco Energy Services will recognize the salvage proceeds associated with the scrap metals at the facility as realized.

Corporate and Other

Between 1990 and 1999, Potomac Capital Investment Corporation (PCI), a wholly-owned subsidiary of PHI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the Internal Revenue Service (IRS) with respect to other taxpayers' cross-border lease and other structured transactions (see "Discontinued Operations – Cross-Border Energy Lease Investments" below), (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI would be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of all relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances.

Discontinued Operations

Cross-Border Energy Lease Investments

Through its subsidiary PCI, PHI held a portfolio of cross-border energy lease investments. During 2013, PHI completed the termination of its interest in its cross-border energy lease investments and, as a result, these investments are being accounted for as discontinued operations.

Pepco Energy Services

In December 2009, PHI announced the wind-down of the retail energy supply component of the Pepco Energy Services business which was comprised of the retail electric and natural gas supply businesses. Pepco Energy Services implemented the wind-down by not entering into any new retail electric or natural gas supply contracts while continuing to perform under its existing retail electric and natural gas supply contracts through their respective expiration dates. On March 21, 2013, Pepco Energy Services entered into an agreement whereby a third party assumed all the rights and obligations of the remaining retail natural gas supply customer contracts, and the associated supply obligations, inventory and derivative contracts. The transaction was completed on April 1, 2013. In addition, Pepco Energy Services completed the wind-down of its retail electric supply business in the second quarter of 2013 by terminating its remaining customer supply and wholesale purchase obligations beyond June 30, 2013.

The operations of Pepco Energy Services' retail electric and natural gas supply businesses have been classified as discontinued operations and are no longer a part of the Pepco Energy Services segment for financial reporting purposes.

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

Pepco Holdings' unaudited consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. Therefore, these consolidated financial statements should be read along with the annual consolidated financial statements included in PHI's annual report on Form 10-K for the year ended December 31, 2013. In the opinion of PHI's management, the unaudited consolidated financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly Pepco Holdings' financial condition as of June 30, 2014, in accordance with GAAP. The year-end December 31, 2013 consolidated balance sheet included herein was derived from audited consolidated financial statements, but does not include all disclosures required by GAAP. Interim results for the three and six months ended June 30, 2014 may not be indicative of PHI's results that will be realized for the full year ending December 31, 2014.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the consolidated financial statements and accompanying notes. Although Pepco Holdings believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset and goodwill impairment calculations, fair value calculations for derivative instruments, pension and other postretirement benefit assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of loss contingency liabilities for general litigation and auto and other liability claims, accrual of interest related to income taxes, the recognition of lease income and income tax benefits for investments in finance leases held in trust associated with PHI's former cross-border energy lease investments (see Note (18), "Discontinued Operations – Cross-Border Energy Lease Investments"), and income tax provisions and reserves. Additionally, PHI is subject to legal, regulatory and other proceedings and claims that arise in the ordinary course of its business. PHI records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Consolidation of Variable Interest Entities

PHI assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests. See Note (16), "Variable Interest Entities," for additional information.

Goodwill

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired at the acquisition date. PHI tests its goodwill for impairment annually as of November 1 and whenever an event occurs or circumstances change in the interim that would more likely than not (that is, a greater than 50% chance) reduce the estimated fair value of a reporting unit below the carrying amount of its net assets. Factors that may result in an interim impairment test include, but are not limited to: a change in the identified reporting units, an adverse change in business conditions, a protracted decline in PHI's stock price causing market capitalization to fall significantly below book value, an adverse regulatory action, or an impairment of long-lived assets in the reporting unit. PHI performed its most recent annual impairment test as of November 1, 2013, and its goodwill was not impaired as described in Note (6), "Goodwill."

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco Holdings' gross revenues were $78 million and $83 million for the three months ended June 30, 2014 and 2013, respectively, and $161 million and $166 million for the six months ended June 30, 2014 and 2013, respectively.

Reclassifications

Certain prior period amounts have been reclassified in order to conform to the current period presentation.

Revisions of Prior Period Financial Statements

Operating and Financing Cash Flows

The consolidated statement of cash flows for the six months ended June 30, 2013 has been revised to correctly present changes in book overdraft balances as operating activities (included in Changes in accounts payable and accrued liabilities) rather than financing activities (included in Net other financing activities). For the six months ended June 30, 2013, the effect of the revision was to increase Net cash used by operating activities by $12 million from $35 million to $47 million, and decrease Net cash used by financing activities by $12 million from $58 million to $46 million. The revision was not considered to be material, individually or in the aggregate, to previously issued financial statements.

PCI Deferred Income Tax Liability Adjustment

Since 1999, PCI had not recorded a deferred tax liability related to a temporary difference between the financial reporting basis and the tax basis of an investment in a wholly owned partnership. In the second quarter of 2013, PHI re-evaluated this accounting treatment and found it to be in error, requiring a $32 million charge to earnings related to prior periods. The adjustment was not considered to be material, individually or in the aggregate, to previously issued financial statements; however, the cumulative impact would have been material to PHI's reported net income in 2013, if corrected in 2013. As a result, during the second quarter of 2013, PHI revised its prior period financial statements to correct this error.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Liabilities (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, PHI is required to measure such obligations as the sum of the amount it agreed to pay on the basis of its arrangement among co-obligors and any additional amount it expects to pay on behalf of its co-obligors. Adoption of this guidance during the first quarter of 2014 did not have a material impact on PHI's consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance requiring netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The prospective adoption of this guidance at March 31, 2014 resulted in PHI netting liabilities related to uncertain tax positions with deferred tax assets for net operating loss and other carryforwards (included in deferred income tax liabilities, net) and income taxes receivable (including income tax deposits) related to effectively settled uncertain tax positions.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements are effective for PHI beginning January 1, 2017, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2017. Early adoption is not permitted. PHI is currently evaluating the potential impact of this new guidance on its consolidated financial statements and which implementation approach to select.

(5) SEGMENT INFORMATION

Pepco Holdings' management has identified its operating segments at June 30, 2014 as Power Delivery and Pepco Energy Services. In the tables below, the Corporate and Other column is included to reconcile the segment data with consolidated data and includes unallocated Pepco Holdings' (parent company) capital costs, such as financing costs. Through its subsidiary PCI, PHI maintained a portfolio of cross-border energy lease investments. PHI completed the termination of its interests in its cross-border energy lease investments during 2013. As a result, the cross-border energy lease investments, which comprised substantially all of the operations of the former Other Non-Regulated segment, are being accounted for as discontinued operations.

The remaining operations of the former Other Non-Regulated segment, which no longer meet the definition of a separate segment for financial reporting purposes, are now included in Corporate and Other. Segment financial information for continuing operations for the three and six months ended June 30, 2014 and 2013 are as follows:

	Three Months Ended June 30, 2014			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 1,040	$ 79	$ (2)	$ 1,117
Operating Expenses (b)	881	77	8	966
Operating Income (Loss)	159	2	(10)	151
Interest and Dividend Income	—	—	1	1
Interest Expense	56	—	11	67
Other Income (Expense)	13	1	(1)	13
Income Tax Expense (Benefit)	45	1	(1)	45
Net Income (Loss) from Continuing Operations	71	2	(20)	53
Total Assets	13,471	297	1,302	15,070
Construction Expenditures	$ 253	$ 1	$ 17	$ 271

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(2) million for Operating Revenue, $(3) million for Operating Expenses, $1 million for Interest Expense and $(1) million for Interest and Dividend Income.

(b) Includes depreciation and amortization expense of $132 million, consisting of $122 million for Power Delivery, $2 million for Pepco Energy Services and $8 million for Corporate and Other.

	Three Months Ended June 30, 2013			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 1,006	$ 49	$ (4)	$ 1,051
Operating Expenses (b)	866	47	(7)	906
Operating Income	140	2	3	145
Interest Expense	58	—	12	70
Other Income	7	—	1	8
Income Tax Expense (Benefit)	33	1	(4)	30
Net Income (Loss) from Continuing Operations	56	1	(4)	53
Total Assets (excluding Assets Held for Disposition)	12,535	350	1,923	14,808
Construction Expenditures	$ 281	$ —	$ 39	$ 320

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(5) million for Operating Revenue and $(5) million for Operating Expenses.

(b) Includes depreciation and amortization expense of $116 million, consisting of $107 million for Power Delivery, $2 million for Pepco Energy Services and $7 million for Corporate and Other.

	Six Months Ended June 30, 2014			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 2,312	$ 139	$ (4)	$ 2,447
Operating Expenses (b)	1,984	137	2	2,123
Operating Income (Loss)	328	2	(6)	324
Interest and Dividend Income	—	—	1	1
Interest Expense	111	—	21	132
Other Income	25	1	—	26
Income Tax Expense (Benefit)	92	1	(2)	91
Net Income (Loss) from Continuing Operations	150	2	(24)	128
Total Assets	13,471	297	1,302	15,070
Construction Expenditures	$ 517	$ 1	$ 35	$ 553

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(4) million for Operating Revenue, $(4) million for Operating Expenses and $(1) million for Interest and Dividend Income.

(b) Includes depreciation and amortization expense of $265 million, consisting of $246 million for Power Delivery, $4 million for Pepco Energy Services and $15 million for Corporate and Other.

	Six Months Ended June 30, 2013			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 2,130	$ 106	$ (5)	$ 2,231
Operating Expenses (b)	1,867	101	(15)	1,953
Operating Income	263	5	10	278
Interest Expense	114	—	23	137
Other Income	13	1	2	16
Income Tax Expense (c)	48	2	165 (d)	215
Net Income (Loss) from Continuing Operations	114	4	(176)	(58)
Total Assets (excluding Assets Held for Disposition)	12,535	350	1,923	14,808
Construction Expenditures	$ 563	$ 1	$ 52	$ 616

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(5) million for Operating Revenue, $(6) million for Operating Expenses and $(4) million for Interest Expense.

(b) Includes depreciation and amortization expense of $228 million, consisting of $211 million for Power Delivery, $4 million for Pepco Energy Services and $13 million for Corporate and Other.

(c) Includes after-tax interest associated with uncertain and effectively settled tax positions allocated to each member of the consolidated group, including a $12 million interest benefit for Power Delivery and interest expense of $66 million for Corporate and Other.

(d) Includes non-cash charges of $101 million representing the establishment of valuation allowances against certain deferred tax assets of PCI included in Corporate and Other.

(6) GOODWILL

PHI's goodwill balance of $1,407 million was unchanged during the six months ended June 30, 2014. Substantially all of PHI's goodwill balance was generated by Pepco's acquisition of Conectiv (known as Conectiv, LLC, and the parent of DPL and ACE, and referred to herein as Conectiv) in 2002 and is allocated entirely to the Power Delivery reporting unit based on the aggregation of its regulated public utility company components for purposes of assessing impairment under FASB guidance on goodwill and other intangibles (ASC 350).

PHI's annual impairment test as of November 1, 2013 indicated that goodwill was not impaired. For the six months ended June 30, 2014, PHI concluded that there were no events or circumstances requiring it to perform an interim goodwill impairment test. PHI will perform its next annual impairment test as of November 1, 2014.

(7) REGULATORY MATTERS

Rate Proceedings

The following table shows, for each of PHI's utility subsidiaries, the electric distribution base rate cases currently pending. Additional information concerning the filing is provided in the discussion below.

Jurisdiction/Company	Requested Revenue Requirement Increase *(millions of dollars)*	Requested Return on Equity	Filing Date	Expected Timing of Decision
NJ – ACE	$ 61.7	10.25%	March 14, 2014	Q1, 2015

The following table shows, for each of PHI's utility subsidiaries, the distribution base rate cases completed to date in 2014. Additional information concerning each of these cases is provided in the discussion below.

Jurisdiction/Company	Approved Revenue Requirement Increase *(millions of dollars)*	Approved Return on Equity	Completion Date	Rate Effective Date
DC – Pepco	$ 23.4	9.40%	March 26, 2014	April 16, 2014
DE – DPL (Electric)	$ 15.1	9.70%	April 2, 2014	May 1, 2014
MD – Pepco	$ 8.8	9.62%	July 2, 2014	July 4, 2014

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings as indicated below.

Bill Stabilization Adjustment

PHI's utility subsidiaries have proposed in each of their respective jurisdictions the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. To date:

- A bill stabilization adjustment (BSA) has been approved and implemented for Pepco and DPL electric service in Maryland and for Pepco electric service in the District of Columbia.
- A proposed modified fixed variable rate design (MFVRD) for DPL electric and natural gas service in Delaware was filed in 2009 for consideration by the DPSC and while there was little activity associated with this filing in 2013, or to date in 2014, the proceeding remains open.
- In New Jersey, a BSA proposed by ACE in 2009 was not approved and there is no BSA proposal currently pending.

Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission. The MFVRD proposed in Delaware contemplates a fixed customer charge (i.e., not tied to the customer's volumetric consumption of electricity or natural gas) to recover the utility's fixed costs, plus a reasonable rate of return.

Delaware

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The application sought approval of an annual rate increase of approximately $42 million (adjusted by DPL to approximately $39 million on September 20, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on June 1, 2013, subject to refund and pending final DPSC approval. On October 8, 2013, the DPSC approved DPL's request to implement an additional interim increase of $25.1 million, effective on October 22, 2013, bringing the total interim rates in effect subject to refund to $27.6 million. At the conclusion of a meeting held on April 1 and 2, 2014, the DPSC issued an order providing for an annual increase in DPL's electric distribution base rates of approximately $15.1 million, based on an ROE of 9.70%. The amounts contained in the DPSC order are subject to verification by all parties to the base rate proceeding and may be changed by further order of the DPSC upon such verification. A final order in this proceeding is expected to be issued by the DPSC in the third quarter of 2014. The new rates became effective May 1, 2014. DPL will submit a rate refund plan to provide credit or refund to any customer whose rates were increased in October 2013 in an amount that exceeded the increase approved by the DPSC. It is anticipated that refunds will be issued beginning September 2, 2014. The final order in this proceeding is not expected to be affected by the Merger Agreement. Under the Merger Agreement, DPL is not permitted to file further electric distribution base rate cases in Delaware without Exelon's consent.

Forward Looking Rate Plan

On October 2, 2013, DPL filed a multi-year rate plan, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would provide for annual electric distribution base rate increases over a four-year period in the aggregate amount of approximately $56 million. The FLRP as proposed provides the opportunity to achieve estimated earned ROEs of 7.41% and 8.80% in years one and two, respectively, and 9.75% in both years three and four of the plan.

In addition, DPL proposed that as part of the FLRP, in order to provide a higher minimum required standard of reliability for DPL's customers than that to which DPL is currently subject, the standards by which DPL's reliability is measured would be made more stringent in each year of the FLRP. DPL has also offered to refund an aggregate of $500,000 to customers in each year of the FLRP that it fails to meet the proposed stricter minimum reliability standards.

On October 22, 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that it would not address the FLRP until the electric distribution base rate case discussed above was concluded. A schedule for the FLRP docket has not yet been established. Under the Merger Agreement, DPL is permitted to pursue this matter.

Gas Distribution Base Rates

A settlement approved in October 2013 by the DPSC in a proceeding filed by DPL in December 2012 to increase its natural gas distribution base rates provides in part for a phase-in of the recovery of the deferred costs associated with DPL's deployment of the interface management unit (IMU). The IMU is part of DPL's advanced metering infrastructure (AMI) and allows for the remote reading of gas meters. Recovery of such costs will occur through base rates over a two-year period, assuming specific milestones are met and pursuant to the following schedule: 50% of the IMU portion of DPL's advanced metering infrastructure (AMI) was put into rates on July 11, 2014, and the remainder will be put into rates on April 1, 2015. DPL also agreed in the settlement that its next natural gas distribution base rate application may be filed with the DPSC no earlier than January 1, 2015. Under the Merger Agreement, DPL is not permitted to file further gas distribution base rate cases without Exelon's consent.

Gas Cost Rates

DPL makes an annual Gas Cost Rate (GCR) filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. On August 28, 2013, DPL made its 2013 GCR filing. The rates proposed in the 2013 GCR filing would result in a GCR decrease of approximately 5.5%. On September 26, 2013, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2013, subject to refund and pending final DPSC approval. On July 8, 2014, the DPSC issued an order approving the GCR rates as filed by DPL. Under the Merger Agreement, DPL is permitted to continue to file its required annual GCR cases in Delaware.

<u>District of Columbia</u>

On March 8, 2013, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by approximately $52.1 million (adjusted by Pepco to approximately $44.8 million on December 3, 2013), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. On March 26, 2014, the DCPSC issued an order approving an increase in base rates of approximately $23.4 million, based on an ROE of 9.40%. The new rates became effective on April 16, 2014. On April 28, 2014, Pepco filed an application for reconsideration or clarification of the DCPSC's March 26, 2014 order, contesting several of the reporting obligations and other directives imposed by the order. On April 29, 2014, the other parties to the proceeding filed applications for reconsideration of the March 26, 2014 order, which generally challenge Pepco's post-test year reliability projects, the adequacy of Pepco's environmental and efficiency measures, and the structure of Pepco's residential aid discount rate. On July 10, 2014, the DCPSC issued its order on reconsideration, which granted in part and denied in part Pepco's application for reconsideration with regard to reporting obligations. The DCPSC also rejected the other parties' applications for reconsideration challenging Pepco's recovery for several post-test year reliability projects. Under the Merger Agreement, Pepco is permitted to continue to pursue action in this matter to its conclusion, but Pepco is not permitted to initiate or file further electric distribution base rate cases in the District of Columbia without Exelon's consent.

<u>Maryland</u>

Pepco Electric Distribution Base Rates

In December 2011, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently adjusted by Pepco to approximately $66.2 million), based on a requested ROE of 10.75%. In July 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. Among other things, the order also authorized Pepco to recover the actual cost of AMI meters installed during the 2011 test year, stating that cost recovery for AMI deployment will be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new rates became effective on July 20, 2012. The Maryland Office of People's Counsel (OPC) has sought rehearing on the portion of the order allowing Pepco to recover the costs of AMI meters installed during the test year; that motion remains pending.

On November 30, 2012, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $60.8 million, based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. Pepco also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $192 million associated with its plan to accelerate investments in infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force. Specific projects under Pepco's Grid Resiliency Charge plan included acceleration of its tree-trimming cycle, upgrade of 12 additional feeders per year for two years and undergrounding of six distribution feeders. In addition, Pepco proposed a reliability performance-based mechanism that would allow Pepco to earn up to $1 million as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $1 million in total if Pepco does not meet at least the minimum reliability performance targets. Pepco requested that any credits/charges would flow through the proposed Grid Resiliency Charge rider.

On July 12, 2013, the MPSC issued an order related to Pepco's November 30, 2012 application approving an annual rate increase of approximately $27.9 million, based on an ROE of 9.36%. The order provides for the full recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by including the related capital costs in the rate base and amortizing the related deferred operation and maintenance expenses of $23.6 million over a five-year period. The order excludes the cost of AMI meters from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system; as a result, costs for AMI meters incurred with respect to the 2012 test year and beyond will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system that are deferred and on which a carrying charge is deferred, but only until such cost effectiveness has been demonstrated and such costs are included in rates. However, the MPSC's July 2012 order in Pepco's previous electric distribution base rate case, which allowed Pepco to recover the costs of meters installed during the 2011 test year for that case, remains in effect, and the Maryland OPC's motion for rehearing in that case remains pending.

The order also approved a Grid Resiliency Charge, which went into effect on January 1, 2014, for recovery of costs totaling approximately $24.0 million associated with Pepco's proposed plan to accelerate investments related to certain priority feeders, provided that, before implementing the surcharge, Pepco (i) provides additional information to the MPSC related to performance objectives, milestones and costs, and (ii) makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for each following year. The MPSC did not approve the proposed acceleration of the tree-trimming cycle or the undergrounding of six distribution feeders. The MPSC also rejected Pepco's proposed reliability performance-based mechanism. The new rates were effective on July 12, 2013.

On July 26, 2013, Pepco filed a notice of appeal of the July 12, 2013 order in the Circuit Court for the City of Baltimore. Other parties also have filed notices of appeal, which have been consolidated with Pepco's appeal. In its memorandum filed with the appeals court, Pepco asserts that the MPSC erred in failing to grant Pepco an adequate ROE, denying a number of other cost recovery mechanisms and limiting Pepco's test year data to no more than four months of forecasted data in future rate cases. The memoranda filed with the appeals court by the other parties primarily assert that the MPSC erred or acted arbitrarily and capriciously in allowing the recovery of certain costs by Pepco and refusing to reduce Pepco's rate base by known and measurable accumulated depreciation. The appeal remains pending.

On December 4, 2013, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $43.3 million (adjusted by Pepco to approximately $37.4 million on April 15, 2014), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. On July 2, 2014, the MPSC issued an order related to Pepco's December 2013 application approving an annual rate increase of approximately $8.75 million, based on an ROE of 9.62%. The new rates became effective on July 4, 2014.

Under the Merger Agreement, Pepco is permitted, and intends to continue, to pursue the conclusion of the aforementioned matters, but under the Merger Agreement, Pepco is not permitted to initiate or file further electric distribution base rate cases in Maryland without Exelon's consent.

<u>*New Jersey*</u>

Electric Distribution Base Rates

On March 14, 2014, ACE submitted an application with the NJBPU to increase its electric distribution base rates by approximately $61.7 million (excluding sales and use taxes), based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with ACE's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. The application requests that the NJBPU put rates into effect by mid-December 2014. The matter has been transmitted by NJBPU to the Office of Administrative Law. Consistent with the procedural schedule for the proceeding, the parties are engaged in settlement negotiations. Absent entering into a settlement agreement that is ultimately approved by the NJBPU, ACE would anticipate that a fully-litigated decision in this proceeding would be issued by the NJBPU in the first quarter of 2015. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue the conclusion of the aforementioned matter, but under the Merger Agreement, ACE is not permitted to initiate or file further electric distribution base rate cases in New Jersey without Exelon's consent.

Update and Reconciliation of Certain Under-Recovered Balances

On March 3, 2014, ACE submitted a petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators (NUGs), (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The net impact of adjusting the charges as proposed is an overall annual rate decrease of approximately $24.5 million (revised to a decrease of approximately $41.1 million on April 16, 2014, based upon an update for actual data through March 2014). In May 2014, the NJBPU approved a stipulation of settlement entered into by the parties in this proceeding providing for an overall annual rate decrease of $41.1 million. The rate decrease, which went into effect on June 1, 2014, will have no effect on ACE's operating income and was placed into effect provisionally subject to a review by the NJBPU of the final underlying costs for reasonableness and prudence. The final order in this proceeding is not expected to be affected by the Merger Agreement.

Service Extension Contributions Refund Order

On July 19, 2013, in compliance with a 2012 Superior Court of New Jersey Appellate Division (Appellate Division) court decision, the NJBPU released an order requiring utilities to issue refunds to persons or entities that paid non-refundable contributions for utility service extensions to certain areas described as "Areas Not Designated for Growth." The order is limited to eligible contributions paid between March 20, 2005 and December 20, 2009. ACE is processing the refund requests that meet the eligibility criteria established in the order as they are received. Although ACE estimates that it received approximately $11 million of contributions between March 20, 2005 and December 20, 2009, it is currently unable to reasonably estimate the amount that it may be required to refund using the eligibility criteria established by the order. Since the July 2013 order was released, ACE has received less than $1 million in refund claims, the validity of which is being investigated by ACE prior to making any such refunds. At this time, ACE does not expect that any such amount refunded will have a material effect on its consolidated financial condition, results of operations or cash flows, as any amounts that may be refunded will generally increase the value of ACE's property, plant and equipment and may ultimately be recovered through depreciation and cost of service. It is anticipated that the NJBPU will commence a rulemaking proceeding to further implement the directives of the Appellate Division decision. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue the conclusion of this matter.

Generic Consolidated Tax Adjustment Proceeding

In January 2013, the NJBPU initiated a generic proceeding to examine whether a consolidated tax adjustment (CTA) should continue to be used, and if so, how it should be calculated in determining a utility's cost of service. Under the NJBPU's current policy, when a New Jersey utility is included in a consolidated group income tax return, an allocated amount of any reduction in the consolidated group's taxes as a result of losses by affiliates is used to reduce the utility's rate base, upon which the utility earns a return. This policy has negatively impacted ACE's base rate case outcomes and ACE's position is that the CTA should be eliminated. A stakeholder process has been initiated by the NJBPU to aid in this examination. On June 18, 2014, NJBPU staff released a Notice of Opportunity to Provide Additional Information in this proceeding (the June 2014 Notice). The June 2014 Notice invited comments on a staff proposal to modify, but not eliminate, the existing CTA. Responses are due on or before August 18, 2014. No formal schedule has been set by the NJBPU for the remainder of the proceeding or for the issuance of a final decision. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue this matter.

Federal Energy Regulatory Commission

In October 2013, FERC issued a ruling on challenges filed by the Delaware Municipal Electric Corporation, Inc. (DEMEC) to DPL's 2011 and 2012 annual formula rate updates. In 2006, FERC approved a formula rate for DPL that is incorporated into the PJM Interconnection, LLC (PJM) tariff. The formula rate establishes the treatment of costs and revenues and the resulting rates for DPL. Pursuant to the protocols approved by FERC and after a period of discovery, interested parties have an opportunity to file challenges regarding the application of the formula rate. The October 2013 FERC order sets various issues in this proceeding for hearing, including challenges regarding formula rate inputs, deferred income items, prepayments of estimated income taxes, rate base reductions, various administrative and general expenses and the inclusion in rate base of construction work in progress related to the Mid-Atlantic Power Pathway (MAPP) project abandoned by PJM. Settlement discussions began in this matter in November 2013 before an administrative law judge at FERC.

In December 2013, DEMEC filed a formal challenge to the DPL 2013 annual formula rate update, including a request to consolidate the 2013 challenge with the two prior challenges. On April 8, 2014, FERC issued an order setting the 2013 challenge issues for hearing and on April 15, 2014, those issues were consolidated with the 2011 and 2012 challenges. Settlement procedures will continue with the three challenges in one proceeding. PHI cannot predict when a final FERC decision in this proceeding will be issued.

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as DEMEC, filed a joint complaint with FERC against Pepco, DPL and ACE, as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. PHI, Pepco, DPL and ACE believe the allegations in this complaint are without merit and are vigorously contesting it. In April 2013, Pepco, DPL and ACE filed their answer to this complaint, requesting that FERC dismiss the complaint against them on the grounds that the complaint failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. PHI cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, PHI is permitted, and intends to continue, to pursue the conclusion of these matters.

On June 19, 2014, FERC issued an order in a proceeding in which the PHI utilities were not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint, Pepco, DPL and ACE believe that it is probable that FERC will direct each utility to use this methodology at the time it issues an order addressing the complaint. As a result, Pepco, DPL and ACE applied an estimated ROE based on the two-step methodology announced by FERC for the period over which each of their transmission revenues would be subject to refund as a result of the challenge, and have recorded estimated reserves in the second quarter of 2014 related to this matter.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland. In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 megawatts (MWs) beginning in 2015. The order requires Pepco, DPL and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative SOS loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs' concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that each of the Contract EDCs will recover its costs associated with the contract through surcharges on its respective SOS customers.

In April 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC's order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. The Maryland circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, Pepco and DPL each entered into identical contracts in accordance with the terms of the MPSC's order; however, under each contract's terms, it will not become effective, if at all, until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit. On June 2, 2014, the Fourth Circuit issued a decision affirming the lower Federal court judgment. On June 16, 2014, both the winning bidder and the MPSC sought rehearing of the Fourth Circuit's decision. On June 30, 2014, the Fourth Circuit denied the rehearing requests of the winning bidder and the MPSC. On July 8, 2014, the Fourth Circuit issued its mandate stating that its decision takes effect on that date, which means that the parties have until September 29, 2014 to appeal the Fourth Circuit's decision to the U.S. Supreme Court. The appeal to the Maryland Court of Special Appeals remains pending.

On June 2, 2014, the winning bidder filed the contracts at FERC requesting that they be accepted pursuant to Section 205 of the Federal Power Act. The Contract EDCs intervened in the proceeding and requested that the winning bidder's filing be rejected on the grounds that the contracts never came into effect.

Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, PHI continues to believe that Pepco and DPL may be required to record their proportional share of the contracts as derivative instruments at fair value and record related regulatory assets of approximately the same amount because Pepco and DPL would recover any payments under the contracts from SOS customers. PHI, Pepco and DPL have concluded that any accounting for these contracts would not be required until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

PHI, Pepco and DPL continue to evaluate these proceedings to determine, should the contracts be found to be valid and enforceable, (i) the extent of the negative effect that the contracts may have on PHI's, Pepco's and DPL's respective credit metrics, as calculated by independent rating agencies that evaluate and rate PHI, Pepco and DPL and their debt issuances, (ii) the effect on Pepco's and DPL's ability to recover their associated costs of the contracts if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contracts on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three Standard Offer Capacity Agreements (SOCAs) by order of the NJBPU, each with a different generation company. ACE and the other New Jersey EDCs entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators were dismissed without prejudice subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. On October 11, 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause, and is therefore null and void. On October 21, 2013 a joint motion to stay the Federal district court's decision pending appeal was filed by the NJBPU and one of the SOCA generation companies. In that motion, the NJBPU notified the Federal district court that it would take no action to force implementation of the SOCAs pending the appeal or such other action—such as FERC approval of the SOCAs—that would cure the constitutional issues to the Federal district court's satisfaction. On October 25, 2013, the Federal district court's issued an order denying the joint motion to stay and ruling that the SOCAs are void, invalid and unenforceable. The SOCA generation companies and the NJBPU appealed the Federal district court's decision. The U.S. Court of Appeals for the Third Circuit heard the appeal on March 27, 2014, but has not rendered a decision.

One of the three SOCAs was terminated effective July 1, 2013 because of an event of default of the generation company that was a party to the SOCA. The remaining two SOCAs were terminated effective November 19, 2013, as a result of a termination notice delivered by ACE after the Federal district court's October 25, 2013 decision.

Despite the terminated status of the SOCAs, one of the generation companies that was a party to a SOCA filed the SOCA at FERC on June 2, 2014, seeking to have the SOCA accepted under Section 205 of the Federal Power Act. The EDCs intervened in the proceeding and requested that the generation company's filing be rejected on the grounds that the SOCA never came into effect.

In light of the Federal district court order (which has not been stayed pending appeal), ACE derecognized both the derivative assets (liabilities) for the estimated fair value of the SOCAs and the related regulatory liabilities (assets) in the fourth quarter of 2013.

District of Columbia Power Line Undergrounding Initiative

In August 2012, the District of Columbia mayor issued an Executive Order establishing the Mayor's Power Line Undergrounding Task Force (the DC Undergrounding Task Force). The stated purpose of the DC Undergrounding Task Force was to pool the collective resources available in the District of Columbia to produce an analysis of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead distribution facilities in the District of Columbia. These resources included legislative bodies, regulators, utility personnel, experts and other parties who could contribute in a meaningful way to the DC Undergrounding Task Force. In October 2013, the DC Undergrounding Task Force issued a Final Report of its findings and recommendations endorsing a $1 billion initiative to selectively place underground some of the District of Columbia's most outage-prone power lines, which lines and surrounding conduit would be owned and maintained by Pepco. The initiative is known as the District of Columbia Power Line Undergrounding (or DC PLUG) initiative.

The legislation providing for implementation of the Final Report's recommendations contemplates that: (i) Pepco will fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost will be financed by the District of Columbia's issuance of securitized bonds, which bonds will be repaid through a surcharge on the electric bills of Pepco District of Columbia customers that Pepco will remit to the District of Columbia; and (iii) the remaining amount will be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount. The enabling legislation, entitled the Electric Company Infrastructure Improvement Financing Act of 2013 (the Improvement Financing Act), became effective on May 3, 2014. The application for the financing order will be filed by Pepco with the DCPSC in August 2014. The final steps in the approval process are DCPSC authorization of the DC PLUG Application and Triennial Plan filed by Pepco and DDOT on June 17, 2014, and DCPSC issuance of a financing order as required by the Improvement Financing Act. These approvals would permit (i) Pepco and DDOT to commence their proposed construction plan; (ii) the District of Columbia to issue the necessary bonds to fund the District of Columbia's portion of the DC PLUG initiative; and (iii) the establishment of the customer surcharges contemplated by the Improvement Financing Act. The DCPSC's orders are anticipated in the fourth quarter of 2014. Under the Merger Agreement, Pepco is permitted, and intends to continue, to pursue the DC PLUG initiative.

MAPP Settlement Agreement

In February 2014, FERC issued an order approving the settlement agreement submitted by Pepco and DPL in connection with Pepco's and DPL's proceeding seeking recovery of approximately $88 million in abandonment costs related to the MAPP project. PHI had been directed by PJM to construct the MAPP project, a 152-mile high-voltage interstate transmission line, and was subsequently directed by PJM to cancel it. The abandonment costs sought for recovery were subsequently reduced to $82 million from write-offs of certain disallowed costs in 2013 and transfers of materials to inventories for use on other projects. Under the terms of the FERC-approved settlement agreement, Pepco and DPL will receive $80.5 million of transmission revenues over a three-year period, which began on June 1, 2013, and will retain title to all real property and property rights acquired in connection with the MAPP project, which had an estimated fair value of $8 million. The FERC-approved settlement agreement resolves all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project, and the terms of the settlement agreement are not subject to modification through any other FERC proceeding. As of June 30, 2014, PHI had a regulatory asset related to the MAPP abandonment costs of approximately $46 million, net of amortization, and land of $8 million. PHI expects to recognize pre-tax income related to the MAPP abandonment costs of $3 million in 2014 and $1 million in 2015.

Merger Approval Proceedings

Delaware

On June 18, 2014, Exelon, PHI and DPL, and certain of their respective affiliates, filed an application with the DPSC seeking approval of the Merger. Delaware law requires the DPSC to approve the Merger when it determines that the transaction is in accordance with law, for a proper purpose, and is consistent with the public interest. The DPSC must further find that the successor will continue to provide safe and reliable service, will not terminate or impair existing collective bargaining agreements and will engage in good faith bargaining with organized labor. By statute, the review of this application must be concluded within 120 days, unless additional time is agreed to by the applicants and the DPSC. On July 8, 2014, the DPSC issued an order approving the schedule agreed to by the parties, which provides for a final DPSC order in this proceeding to be issued on or before January 6, 2015.

District of Columbia

On June 18, 2014, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application with the DCPSC seeking approval of the Merger. To approve the Merger, the DCPSC must find that the Merger is in the public interest. In an order issued June 27, 2014, the DCPSC stated that to make the determination of whether the transaction is in the public interest, it will analyze the transaction in the context of six factors to determine whether the transaction balances the interests of shareholders and investors with ratepayers and the community, whether the benefits to shareholders do or do not come at the expense of the ratepayers, and whether the transaction produces a direct and tangible benefit to ratepayers. The six factors identified by the DCPSC are the effects of the transaction on: (i) ratepayers, shareholders, the financial health of the utility standing alone and as merged, and the local economy; (ii) utility management and administrative operations; (iii) the safety and reliability of services; (iv) risks associated with nuclear operations; (v) the DCPSC's ability to regulate the new utility effectively; and (vi) competition in the local utility market.

The law of the District of Columbia does not impose any time limit on the DCPSC's review of the Merger, and a procedural schedule for this proceeding has not yet been set.

Maryland

Approval of the Merger by the MPSC is required, but the application for approval of the Merger has not yet been filed. Maryland law requires the MPSC to approve a merger subject to its review if it finds that the merger is consistent with the public interest, convenience and necessity, including its benefits to and impact on consumers. In making this determination, the MPSC is required to consider the following 12 criteria: (i) the potential impact of the merger on rates and charges paid by customers and on the services and conditions of operation of the utility; (ii) the potential impact of the merger on continuing investment needs for the maintenance of utility services, plant and related infrastructure; (iii) the proposed capital structure that will result from the merger, including allocation of earnings from the utility; (iv) the potential effects on employment by the utility; (v) the projected allocation between the utility's shareholders and ratepayers of any savings that are expected; (vi) issues of reliability, quality of service and quality of customer service; (vii) the potential impact of the merger on community investment; (viii) affiliate and cross-subsidization issues; (ix) the use or pledge of utility assets for the benefit of an affiliate; (x) jurisdictional and choice-of-law issues; (xi) whether it is necessary to revise the MPSC's ring-fencing and affiliate code of conduct regulations in light of the merger; and (xii) any other issues the MPSC considers relevant to the assessment of the merger. Once the application is filed, the MPSC is required to issue an order within 180 days. However, the MPSC can grant a 45-day extension for good cause. If no order is issued by the statutory deadline, then the Merger would be deemed to be approved. PHI anticipates filing the merger approval application with the MPSC in the third quarter of 2014.

New Jersey

On June 18, 2014, Exelon, PHI and ACE, and certain of their respective affiliates, filed a petition with the NJBPU seeking approval of the Merger. To approve the Merger, the NJBPU must find the Merger is in the public interest, and consider the impact of the Merger on (i) competition, (ii) rates of ratepayers affected by the Merger, (iii) ACE's employees, and (iv) the provision of safe and reliable service at just and reasonable rates. On July 23, 2014, the NJBPU voted to retain this matter, rather than assigning it to an administrative law judge. New Jersey law does not impose any time limit on the NJBPU's review of the Merger, and a procedural schedule for this proceeding has not yet been set.

Virginia

On June 3, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, filed an application with the VSCC seeking approval of the Merger. Virginia law provides that, if the VSCC determines, with or without hearing, that adequate service to the public at just and reasonable rates will not be impaired or jeopardized by granting the application for approval, then the VSCC shall approve a merger with such conditions that the VSCC deems to be appropriate in order to satisfy this standard. The VSCC is required to rule on the application within 60 days, which may be extended by up to 120 days. On June 16, 2014, the VSCC issued an order extending the time period for issuing a decision by an additional 60 days, to October 1, 2014.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the Federal Power Act. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. The companies requested that FERC find that the transaction is consistent with the public interest and grant approval within 90 days.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

The table below provides the components of net periodic benefit costs recognized by Pepco Holdings for the three months ended June 30, 2014 and 2013:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(millions of dollars)			
Service cost	$ 9	$ 13	$ 2	$ 2
Interest cost	28	25	6	8
Expected return on plan assets	(36)	(36)	(6)	(5)
Amortization of prior service cost (benefit)	1	1	(4)	(1)
Amortization of net actuarial loss	11	18	(1)	4
Net periodic benefit cost	$ 13	$ 21	$ (3)	$ 8

The table below provides the components of net periodic benefit costs recognized by Pepco Holdings for the six months ended June 30, 2014 and 2013:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(millions of dollars)			
Service cost	$ 21	$ 26	$ 4	$ 4
Interest cost	55	50	13	16
Expected return on plan assets	(71)	(73)	(12)	(10)
Amortization of prior service cost (benefit)	1	1	(7)	(2)
Amortization of net actuarial loss	22	34	2	8
Net periodic benefit cost	$ 28	$ 38	$ —	$ 16

Pension and Other Postretirement Benefits

Net periodic benefit cost related to continuing operations is included in other operation and maintenance expense, net of the portion of the net periodic benefit cost that is capitalized as part of the cost of labor for internal construction projects. PHI anticipates approximately 37% of annual net periodic pension and other postretirement benefit costs will be capitalized.

Pension Contributions

PHI's funding policy with regard to PHI's non-contributory retirement plan (the PHI Retirement Plan) is to maintain a funding level that is at least equal to the target liability as defined under the Pension Protection Act of 2006. In 2014, PHI, Pepco, DPL and ACE made no discretionary tax-deductible contributions to the PHI Retirement Plan. In the second quarter of 2013, PHI made a discretionary tax-deductible contribution to the PHI Retirement Plan of $60 million. In the first quarter of 2013, PHI, Pepco, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan of $20 million, zero, $10 million and $30 million, respectively, which brought the PHI Retirement Plan assets to the funding target level for 2013 under the Pension Protection Act.

Benefit Plan Modifications

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and the retiree life insurance benefits, and became effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $16 million reduction in net periodic benefit cost for other postretirement benefits during the six months ended June 30, 2014 when compared to the six months ended June 30, 2013.

(9) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility is currently August 1, 2018.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million and the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate (LIBOR) plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of June 30, 2014.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of June 30, 2014 and December 31, 2013, the amount of cash plus unused borrowing capacity under the credit facility available to meet the future liquidity needs of PHI and its utility subsidiaries on a consolidated basis totaled $1,290 million and $1,063 million, respectively. PHI's utility subsidiaries had combined cash and unused borrowing capacity under the credit facility of $736 million and $332 million at June 30, 2014 and December 31, 2013, respectively.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings.

Commercial Paper

PHI, Pepco, DPL and ACE maintain on-going commercial paper programs to address short-term liquidity needs. As of June 30, 2014, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $350 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, Pepco, DPL and ACE had $194 million, zero, zero and $180 million, respectively, of commercial paper outstanding at June 30, 2014. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2014 was 0.52%, 0.27%, 0.26% and 0.25%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2014 was three, six, five and four days, respectively.

Other Financing Activities

PHI Term Loan Agreement

On March 28, 2013, PHI entered into a $250 million term loan agreement due March 27, 2014, pursuant to which PHI had borrowed $250 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.875%. PHI used the net proceeds of the loan under the loan agreement to repay its outstanding $200 million term loan obtained in 2012, and for general corporate purposes. On May 29, 2013, PHI repaid the $250 million term loan with a portion of the net proceeds from the early termination of the cross-border energy lease investments.

ACE Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE's Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of June 30, 2014, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.91%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization); (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions; and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of June 30, 2014.

Bond Issuance

In June 2014, DPL issued $200 million of its 3.50% first mortgage bonds due November 15, 2023. Net proceeds from the issuance of the bonds, which included a premium of $4 million, were used to repay DPL's outstanding commercial paper and for general corporate purposes.

Bond Payments

In April 2014, Atlantic City Electric Transition Funding LLC (ACE Funding) made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

Bond Retirements

In April 2014, Pepco retired, at maturity, $175 million of its 4.65% senior notes. The senior notes were secured by a like principal amount of its 4.65% first mortgage bonds due April 15, 2014, which under Pepco's mortgage and deed of trust were deemed to be satisfied when the senior notes were repaid.

In April 2014, ACE retired, at maturity, $18 million of tax-exempt unsecured variable rate demand bonds issued for the benefit of ACE by the Pollution Control Financing Authority of Salem County.

In April 2014, PCI repaid, at maturity, $11 million of bank loans.

Sale of Receivables

On March 13, 2014, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a Task Order entered into under a General Services Administration area-wide agreement. The purchase price to be received by Pepco by the end of the time period is approximately $12 million. The energy savings project, which is being performed by Pepco Energy Services, is expected to be completed by January 1, 2015. Pursuant to the purchase agreement, following acceptance of the energy savings project, the buyer will be entitled to receive the contract payments under the Task Order payable by the customer over approximately 9 years. At June 30, 2014, $5 million of the purchase price had been received by Pepco.

Financing Activities Subsequent to June 30, 2014

Bond Payments

In July 2014, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

(10) INCOME TAXES

A reconciliation of PHI's consolidated effective income tax rates from continuing operations is as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	(millions of dollars)							
Income tax at federal statutory rate	$ 34	35.0%	$ 29	35.0%	$ 77	35.0%	$ 55	35.0%
Increases (decreases) resulting from:								
State income taxes, net of federal effect	7	7.1%	6	7.2%	15	6.8%	10	6.4%
Asset removal costs	(2)	(2.0)%	(3)	(3.6)%	(5)	(2.3)%	(6)	(3.8)%
Merger-related costs	7	7.1%	—	—	7	3.2%	—	—
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	3	3.6%	—	—	54	34.4%
Establishment of valuation allowances related to deferred tax assets	—	—	—	—	—	—	101	64.3%
Other, net	(1)	(1.3)%	(5)	(6.1)%	(3)	(1.1)%	1	0.6%
Consolidated income tax expense related to continuing operations	$ 45	45.9%	$ 30	36.1%	$ 91	41.6%	$215	136.9%

In connection with entering into the Merger Agreement (as further described in Note (1), "Organization"), PHI incurred certain merger-related costs in the second quarter of 2014 which are not tax deductible and resulted in a higher effective tax rate in the three and six months ended June 30, 2014.

In the first quarter of 2013, PHI recorded interest expense related to uncertain and effectively settled tax positions of $51 million primarily representing the anticipated additional interest expense on estimated federal and state income tax obligations that was allocated to PHI's continuing operations resulting from a change in assessment of tax benefits associated with the former cross-border energy lease investments of PCI in the first quarter of 2013.

Also, in the first quarter of 2013, PHI established valuation allowances of $101 million related to deferred tax assets. Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to other taxpayers' cross-border lease and other structured transactions (as discussed in Note (18), "Discontinued Operations – Cross-Border Energy Lease Investments"), (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI would be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of all relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the IRS issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. In February 2014, the IRS issued revenue procedures that describe how taxpayers should implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. PHI does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its consolidated financial statements.

(11) EQUITY AND EARNINGS PER SHARE

Basic and Diluted Earnings Per Share

PHI's basic and diluted earnings per share (EPS) calculations are shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars, except per share data)			
Income (Numerator):				
Net income (loss) from continuing operations	$ 53	$ 53	$ 128	$ (58)
Net loss from discontinued operations	—	(11)	—	(330)
Net income (loss)	$ 53	$ 42	$ 128	$ (388)
Shares (Denominator) (in millions):				
Weighted average shares outstanding for basic computation:				
Average shares outstanding	251	249	251	243
Adjustment to shares outstanding	—	—	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	251	249	251	243
Net effect of potentially dilutive shares (a)	1	—	—	—
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	252	249	251	243
Basic and Diluted Earnings per Share				
Earnings (loss) per share of common stock from continuing operations	$ 0.21	$ 0.21	$ 0.51	$ (0.24)
Loss per share of common stock from discontinued operations	—	(0.04)	—	(1.36)
Basic and diluted earnings (loss) per share	$ 0.21	$ 0.17	$ 0.51	$ (1.60)

(a) There were no options to purchase shares of common stock that were excluded from the calculation of diluted EPS for each of the three and six months ended June 30, 2014 and 2013.

Equity Forward Transaction

During 2012, PHI entered into an equity forward transaction in connection with a public offering of PHI common stock. Pursuant to the terms of this transaction, a forward counterparty borrowed 17,922,077 shares of PHI's common stock from third parties and sold them to a group of underwriters for $19.25 per share, less an underwriting discount equal to $0.67375 per share. Under the terms of the equity forward transaction, upon physical settlement thereof, PHI was required to issue and deliver shares of PHI common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $18.57625 per share at the time the equity forward transaction was entered into and was subject to reduction from time to time in accordance with the terms of the equity forward transaction. PHI believed that the equity forward transaction substantially eliminated future equity price risk because the forward sale price was determinable as of the date that PHI entered into the equity forward transaction and was only reduced pursuant to the contractual terms of the equity forward transaction through the settlement date, which reductions were not affected by a future change in the market price of the PHI common stock. On February 27, 2013, PHI physically settled the equity forward at the then applicable forward sale price of $17.39 per share. The proceeds of approximately $312 million were used to repay outstanding commercial paper, a portion of which had been issued in order to make capital contributions to the utilities, and for general corporate purposes.

(12) PREFERRED STOCK

In connection with entering into the Merger Agreement (as further described in Note (1), "Organization"), PHI entered into a Subscription Agreement with Exelon, dated April 29, 2014, pursuant to which PHI issued to Exelon 9,000 originally issued shares of Preferred Stock for a purchase price of $90 million on April 30, 2014. In connection with these agreements, Exelon also committed to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following April 29, 2014, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on July 29, 2014, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. If the Merger closes or terminates for any reason, no additional shares of Preferred Stock will be issued pursuant to the Subscription Agreement. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value. If the Merger Agreement is terminated for any other reason, PHI will be required to redeem all issued and outstanding Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

PHI has excluded the Preferred Stock from equity at June 30, 2014 since the Preferred Stock contains conditions for redemption that are not solely within the control of PHI. Management determined that the Preferred Stock contains embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred Stock could be called and redeemed at a nominal par value upon a Regulatory Termination. The embedded call and redemption features on the shares of the Preferred Stock in the event of a Regulatory Termination are separately accounted for as derivatives. The estimated fair value of the derivatives upon issuance of the Preferred Stock was $3 million and has been included in current assets (Prepaid expenses and other) with a corresponding increase in Preferred Stock on the consolidated balance sheet at June 30, 2014 as it is considered to be part of the fair value of the preferred stock upon issuance. These Preferred Stock derivatives were valued using quantitative and qualitative factors at both the issuance date and June 30, 2014, including management's assessment of the likelihood of a Regulatory Termination. Changes in the fair value of these derivatives in future periods would be recorded in income.

(13) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

DPL uses derivative instruments in the form of swaps and over-the-counter options primarily to reduce natural gas commodity price volatility and to limit its customers' exposure to increases in the market price of natural gas under a hedging program approved by the DPSC. DPL uses these derivatives to manage the commodity price risk associated with its physical natural gas purchase contracts. All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all gains and losses related to hedging activities, are deferred under FASB guidance on regulated operations (ASC 980) until recovered from its customers through a fuel adjustment clause approved by the DPSC. The natural gas purchase contracts qualify as normal purchases, which are not required to be recorded in the financial statements until settled. In addition, included in derivative assets are PHI Preferred Stock derivatives which are further described in Note (12), "Preferred Stock."

The tables below identify the balance sheet location and fair values of derivative instruments as of June 30, 2014 and December 31, 2013:

	As of June 30, 2014				
Balance Sheet Caption	Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
			(millions of dollars)		
Derivative assets (current assets)	$ —	$ 3	$ 3	$ —	$ 3
Total Derivative asset	$ —	$ 3	$ 3	$ —	$ 3

	As of December 31, 2013				
Balance Sheet Caption	Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
			(millions of dollars)		
Derivative assets (current assets)	$ —	$ 1	$ 1	$ (1)	$ —
Total Derivative asset	$ —	$ 1	$ 1	$ (1)	$ —

All derivative assets and liabilities available to be offset under master netting arrangements were netted as of June 30, 2014 and December 31, 2013. The amount of cash collateral that was offset against these derivative positions is as follows**:**

	June 30, 2014	December 31, 2013
	(millions of dollars)	
Cash collateral received from counterparties with the obligation to return	$ —	$ (1)

As of June 30, 2014 and December 31, 2013, all PHI cash collateral pledged related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Derivatives Designated as Hedging Instruments

Cash Flow Hedges

Cash Flow Hedges Included in Accumulated Other Comprehensive Loss

PHI also may use derivative instruments from time to time to mitigate the effects of fluctuating interest rates on debt issued in connection with the operation of its businesses. In June 2002, PHI entered into several treasury rate lock transactions in anticipation of the issuance of several series of fixed-rate debt commencing in August 2002. Upon issuance of the fixed-rate debt in August 2002, the treasury rate locks were terminated at a loss. The loss has been deferred in Accumulated Other Comprehensive Loss (AOCL) and is being recognized in interest expense over the life of the debt issued as interest payments are made.

The tables below provide details regarding terminated cash flow hedges included in PHI's consolidated balance sheets as of June 30, 2014 and 2013. The data in the following tables indicate the cumulative net loss after-tax related to terminated cash flow hedges by contract type included in AOCL, the portion of AOCL expected to be reclassified to income during the next 12 months, and the maximum hedge or deferral term:

	As of June 30, 2014		
Contracts	Accumulated Other Comprehensive Loss After-tax	Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Interest rate	$ 9	$ 1	218 months
Total	$ 9	$ 1	

	As of June 30, 2013		
Contracts	Accumulated Other Comprehensive Loss After-tax	Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Interest rate	$ 9	$ 1	230 months
Total	$ 9	$ 1	

Other Derivative Activity

PHI, DPL and ACE have certain derivatives that are not in hedge accounting relationships and are not designated as normal purchases or normal sales. These derivatives are recorded at fair value on the consolidated balance sheets with the gain or loss for changes in fair value recorded in income. In addition, in accordance with FASB guidance on regulated operations, regulatory liabilities or regulatory assets of the same amount are recorded on the consolidated balance sheets and the recognition of the derivative gain or loss is deferred because of the DPSC-approved fuel adjustment clause for DPL's derivatives and the NJBPU order pertaining to the ACE SOCA derivatives. The following table indicates the net unrealized and net realized derivative gains and (losses) arising during the period associated with these derivatives that were recognized in the consolidated statements of income (loss) (through Fuel and purchased energy expense) and that were also deferred as Regulatory liabilities and assets, respectively, for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Net unrealized (losses) gains arising during the period	$ —	$ (9)	$ 2	$ (7)
Net realized gains (losses) recognized during the period	1	1	3	(3)

As of June 30, 2014 and December 31, 2013, the quantities and positions of DPL's net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting were:

	June 30, 2014		December 31, 2013	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
DPL – Natural gas (One Million British Thermal Units (MMBtu))	3,265,000	Long	3,977,500	Long

In addition, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock as further described in Note (12), "Preferred Stock."

Contingent Credit Risk Features

The primary contracts used by the Power Delivery segment for derivative transactions are entered into under the International Swaps and Derivatives Association Master Agreement (ISDA) or similar agreements that closely mirror the principal credit provisions of the ISDA. The ISDAs include a Credit Support Annex (CSA) that governs the mutual posting and administration of collateral security. The failure of a party to comply with an obligation under the CSA, including an obligation to transfer collateral security when due or the failure to maintain any required credit support, constitutes an event of default under the ISDA for which the other party may declare an early termination and liquidation of all transactions entered into under the ISDA, including foreclosure against any collateral security. In addition, some of the ISDAs have cross default provisions under which a default by a party under another commodity or derivative contract, or the breach by a party of another borrowing obligation in excess of a specified threshold, is a breach under the ISDA.

Under the ISDA or similar agreements, the parties establish a dollar threshold of unsecured credit for each party in excess of which the party would be required to post collateral to secure its obligations to the other party. The amount of the unsecured credit threshold varies according to the senior, unsecured debt rating of the respective parties or that of a guarantor of the party's obligations. The fair values of all transactions between the parties are netted under the master netting provisions. Transactions may include derivatives accounted for on-balance sheet as well as those designated as normal purchases and normal sales that are accounted for off-balance sheet. If the aggregate fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The obligations of DPL are stand-alone obligations without the guarantee of PHI. If DPL's debt rating were to fall below "investment grade," the unsecured credit threshold would typically be set at zero and collateral would be required for the entire net loss position. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder.

The gross fair values of DPL's derivative liabilities with credit risk-related contingent features as of June 30, 2014 and December 31, 2013 were zero.

DPL's primary source for posting cash collateral or letters of credit is PHI's credit facility. As of June 30, 2014 and December 31, 2013, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the future liquidity needs of PHI's utility subsidiaries was $736 million and $332 million, respectively.

(14) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

PHI applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). PHI utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, PHI utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, PHI's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. PHI's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value Measurements at June 30, 2014			
Description	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)**	**Significant Other Observable Inputs (Level 2) (a)**	**Significant Unobservable Inputs (Level 3)**
	(millions of dollars)			
ASSETS				
Derivative instruments				
Preferred Stock	$ 3	$ —	$ —	$ 3
Cash equivalents and restricted cash equivalents				
Treasury funds	200	200	—	—
Executive deferred compensation plan assets				
Money market funds	15	15	—	—
Life insurance contracts	67	—	47	20
	$285	$ 215	$ 47	$ 23
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 30	$ —	$ 30	$ —
	$ 30	$ —	$ 30	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2014.

Description	Total	Fair Value Measurements at December 31, 2013 Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Cash equivalents and restricted cash equivalents				
Treasury funds	34	34	—	—
Executive deferred compensation plan assets				
Money market funds	15	15	—	—
Life insurance contracts	66	—	47	19
	$116	$ 50	$ 47	$ 19
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 30	$ —	$ 30	$ —
	$ 30	$ —	$ 30	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2013.
(b) The fair values of derivative assets reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas swaps purchased by DPL as part of a natural gas hedging program approved by the DPSC.

PHI classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis, such as the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Executive deferred compensation plan assets and liabilities categorized as level 2 consist of life insurance policies and certain employment agreement obligations. The life insurance policies are categorized as level 2 assets because they are valued based on the assets underlying the policies, which consist of short-term cash equivalents and fixed income securities that are priced using observable market data and can be liquidated for the value of the underlying assets as of June 30, 2014. The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

The value of certain employment agreement obligations (which are included with life insurance contracts in the tables above) is derived using a discounted cash flow valuation technique. The discounted cash flow calculations are based on a known and certain stream of payments to be made over time that are discounted to determine their net present value. The primary variable input, the discount rate, is based on market-corroborated and observable published rates. These obligations have been classified as level 2 within the fair value hierarchy because the payment streams represent contractually known and certain amounts and the discount rate is based on published, observable data.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Derivative instruments classified as level 3 include embedded call and redemption features on the Preferred Stock as further discussed in Note (12), "Preferred Stock."

Executive deferred compensation plan assets include certain life insurance policies that are valued using the cash surrender value of the policies, net of loans against those policies. The cash surrender values do not represent a quoted price in an active market; therefore, those inputs are unobservable and the policies are categorized as level 3. Cash surrender values are provided by third parties and reviewed by PHI for reasonableness.

Reconciliations of the beginning and ending balances of PHI's fair value measurements using significant unobservable inputs (Level 3) for the six months ended June 30, 2014 and 2013 are shown below:

	Six Months Ended June 30, 2014	
	Preferred Stock	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ —	$ 19
Total gains (losses) (realized and unrealized):		
Included in income	—	2
Included in accumulated other comprehensive loss	—	—
Included in regulatory liabilities	—	—
Purchases	—	—
Issuances	3	(1)
Settlements	—	—
Transfers in (out) of level 3	—	—
Ending balance as of June 30	$ 3	$ 20

	Six Months Ended June 30, 2013		
	Natural Gas	Life Insurance Contracts	Capacity
	(millions of dollars)		
Beginning balance as of January 1	$ (4)	$ 18	$ (3)
Total gains (losses) (realized and unrealized):			
Included in income	—	3	—
Included in accumulated other comprehensive loss	—	—	—
Included in regulatory liabilities and regulatory assets	—	—	(7)
Purchases	—	—	—
Issuances	—	(1)	—
Settlements	4	(1)	—
Transfers in (out) of level 3	—	—	—
Ending balance as of June 30	$ —	$ 19	$ (10)

The breakdown of realized and unrealized gains on level 3 instruments included in income as a component of Other income or Other operation and maintenance expense for the periods below were as follows:

	Six Months Ended June 30, 2014	2013
	(millions of dollars)	
Total net gains included in income for the period	$ 2	$ 3
Change in unrealized gains relating to assets still held at reporting date	$ 2	$ 2

Other Financial Instruments

The estimated fair values of PHI's Long-term debt instruments that are measured at amortized cost in PHI's consolidated financial statements and the associated level of the estimates within the fair value hierarchy as of June 30, 2014 and December 31, 2013 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. PHI's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt and Transition Bonds issued by ACE Funding (Transition Bonds) categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers, and PHI reviews the methodologies and results.

The fair value of Long-term debt categorized as level 3 is based on a discounted cash flow methodology using observable inputs, such as the U.S. Treasury yield, and unobservable inputs, such as credit spreads, because quoted prices for the debt or similar debt in active markets were insufficient. The Long-term project funding represents debt instruments issued by Pepco Energy Services related to its energy savings contracts. Long-term project funding is categorized as level 3 because PHI concluded that the amortized cost carrying amounts for these instruments approximates fair value, which does not represent a quoted price in an active market.

	Fair Value Measurements at June 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$5,528	$ —	$ 4,971	$ 557
Transition bonds (b)	262	—	262	—
Long-term project funding	22	—	—	22
	$5,812	$ —	$ 5,233	$ 579

(a) The carrying amount for Long-term debt was $4,873 million as of June 30, 2014.
(b) The carrying amount for Transition bonds, including amounts due within one year, was $235 million as of June 30, 2014.

Description	Total	Fair Value Measurements at December 31, 2013 Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$4,850	$ —	$ 4,289	$ 561
Transition bonds (b)	284	—	284	—
Long-term project funding	12	—	—	12
	$5,146	$ —	$ 4,573	$ 573

(a) The carrying amount for Long-term debt was $4,456 million as of December 31, 2013.
(b) The carrying amount for Transition bonds, including amounts due within one year, was $255 million as of December 31, 2013.

The carrying amounts of all other financial instruments in the accompanying consolidated financial statements approximate fair value.

(15) COMMITMENTS AND CONTINGENCIES

General Litigation and Other Matters

From time to time, PHI and its subsidiaries are named as defendants in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. PHI and each of its subsidiaries are self-insured against such claims up to a certain self-insured retention amount and maintain insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, PHI's contracts with its vendors generally require the vendors to name PHI and/or its subsidiaries as additional insureds for the amounts at least equal to PHI's self-insured retention. Further, PHI's contracts with its vendors require the vendors to indemnify PHI for various acts and activities that may give rise to claims against PHI. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on PHI's or its subsidiaries' financial condition, results of operations or cash flows. At June 30, 2014, PHI had recorded estimated loss contingency liabilities for general litigation totaling approximately $32 million (including amounts related to the matters specifically described below), and the portion of these estimated loss contingency liabilities in excess of the self-insured retention amount was substantially offset by estimated insurance receivables.

Pepco Substation Injury Claim

In May 2013, a contract worker erecting a scaffold at a Pepco substation came into contact with an energized station service feeder and suffered serious injuries. In August 2013, the individual filed suit against Pepco in the Circuit Court for Montgomery County, Maryland, seeking damages for medical expenses, loss of future earning capacity, pain and suffering and the cost of a life care plan aggregating to a maximum claim of approximately $28.1 million. Discovery is ongoing in the case and, if a settlement cannot be reached with respect to this matter, a trial is expected to begin in October 2014. Pepco has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident, including the policies of the contractor performing the scaffold work (which name Pepco as an additional insured), will offset substantially all of Pepco's costs associated with the resolution of this matter, including Pepco's self-insured retention amount. At June 30, 2014, Pepco has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of June 30, 2014. Pepco has also concluded as of June 30, 2014 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable of substantially the same amount as the related loss contingency liability.

ACE Asbestos Claim

In September 2011, an asbestos complaint was filed in the New Jersey Superior Court, Law Division, against ACE (among other defendants) asserting claims under New Jersey's Wrongful Death and Survival statutes. The complaint, filed by the estate of a decedent who was the wife of a former employee of ACE, alleges that the decedent's mesothelioma was caused by exposure to asbestos brought home by her husband on his work clothes. New Jersey courts have recognized a cause of action against a premise owner in a so-called "take home" case if it can be shown that the harm was foreseeable. In this case, the complaint seeks recovery of an unspecified amount of damages for, among other things, the decedent's past medical expenses, loss of earnings, and pain and suffering between the time of injury and death, and asserts a punitive damage claim. At June 30, 2014, ACE has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of June 30, 2014. However, due to the inherent uncertainty of litigation, ACE is unable to estimate a maximum amount of possible loss because the damages sought are indeterminate and the matter involves facts that ACE believes are distinguishable from the facts of the "take-home" cause of action recognized by the New Jersey courts.

ACE Electrical Contact Injury Claims

In October 2010, a farm combine came into and remained in contact with a primary electric line in ACE's service territory in New Jersey. As a result, two individuals operating the combine received fatal electrical contact injuries. While attempting to rescue those two individuals, another individual sustained third-degree burns to his torso and upper extremities. In September 2012, the individual who received third-degree burns filed suit in New Jersey Superior Court, Salem County. In October 2012, additional suits were filed in the same court by or on behalf of the estates of the deceased individuals. Plaintiffs in each of the cases are seeking indeterminate damages and allege that ACE was negligent in the design, construction, erection, operation and maintenance of its poles, power lines, and equipment, and that ACE failed to warn and protect the public from the foreseeable dangers of farm equipment contacting electric lines. Discovery is ongoing in this matter and the litigation involves a number of other defendants and the filing of numerous cross-claims. ACE has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident will offset ACE's costs associated with the resolution of this matter in excess of ACE's self-insured retention amount. At June 30, 2014, ACE has concluded that a loss is probable with respect to these claims and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of June 30, 2014. ACE has also concluded as of June 30, 2014 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable of substantially the same amount as the loss contingency liability in excess of ACE's self-insured retention amount.

Pepco Energy Services Billing Claims

During 2012, Pepco Energy Services received letters on behalf of two school districts in Maryland, which claim that invoices in connection with electricity supply contracts contained certain allegedly unauthorized charges, totaling approximately $7 million. The school districts also claim additional compounded interest totaling approximately $9 million. Although no litigation involving Pepco Energy Services related to these claims has commenced, in August and September 2013, Pepco Energy Services received correspondence from the Superintendent of each of the school districts advising of the intention to render a decision regarding an unresolved dispute between the school district and Pepco Energy Services. Pepco Energy Services filed timely answers to the Superintendents challenging the authority of the respective Superintendents to render decisions on the claims and also disputing the merits of the allegations regarding unauthorized charges as well as the claims of entitlement to compounded interest. With respect to the claim of one of the school districts, in July 2014 its Superintendent determined that Pepco Energy Services should reimburse the allegedly unauthorized charges related to that district, totaling approximately $3 million, but rejected the school district's claim for interest (representing $4 million of the $9 million of total compounded interest originally claimed). The Superintendent of the other school district has not yet acted on the matter. Both Superintendents have acknowledged the availability of administrative and judicial review of the merits of any decision. As of June 30, 2014, Pepco Energy Services has concluded that a loss is reasonably possible with respect to these claims, but the amount of loss, if any, is not reasonably estimable.

Environmental Matters

PHI, through its subsidiaries, is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of PHI's utility subsidiaries, environmental clean-up costs incurred by Pepco, DPL and ACE generally are included by each company in its respective cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies described below of PHI and its subsidiaries at June 30, 2014 are summarized as follows:

	Transmission and Distribution	Legacy Generation Regulated	Legacy Generation Non-Regulated	Total
		(millions of dollars)		
Beginning balance as of January 1	$ 19	$ 6	$ 5	$ 30
Accruals	—	—	—	—
Payments	1	—	—	1
Ending balance as of June 30	18	6	5	29
Less amounts in Other Current Liabilities	3	1	—	4
Amounts in Other Deferred Credits	$ 15	$ 5	$ 5	$ 25

Conectiv Energy Wholesale Power Generation Sites

In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. PHI is obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million. According to PHI's estimates, the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million. The amount accrued by PHI for the ISRA-required remediation activities at the nine generating facility sites is included in the table above in the column entitled "Legacy Generation – Non-Regulated."

In September 2011, PHI received a request for data from the U.S. Environmental Protection Agency (EPA) regarding operations at the Deepwater generating facility in New Jersey (which was included in the sale to Calpine) between February 2004 and July 1, 2010, to demonstrate compliance with the Clean Air Act's new source review permitting program. PHI responded to the data request. Under the terms of the Calpine sale, PHI is obligated to indemnify Calpine for any failure of PHI, on or prior to the closing date of the sale, to comply with environmental laws attributable to the construction of new, or modification of existing, sources of air emissions. At this time, PHI does not expect this inquiry to have a material adverse effect on its consolidated financial condition, results of operations or cash flows.

Franklin Slag Pile Site

In November 2008, ACE received a general notice letter from EPA concerning the Franklin Slag Pile site in Philadelphia, Pennsylvania, asserting that ACE is a potentially responsible party (PRP) that may have liability for clean-up costs with respect to the site and for the costs of implementing an EPA-mandated remedy. EPA's claims are based on ACE's sale of boiler slag from the B.L. England generating facility, then owned by ACE, to MDC Industries, Inc. (MDC) during the period June 1978 to May 1983. EPA claims that the boiler slag ACE sold to MDC contained copper and lead, which are hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), and that the sales transactions may have constituted an arrangement for the disposal or treatment of hazardous substances at the site, which could be a basis for liability under CERCLA. The EPA letter also states that, as of the date of the letter, EPA's expenditures for response measures at the site have exceeded $6 million. EPA's feasibility study for this site conducted in 2007 identified a range of alternatives for permanent remedial measures with varying cost estimates, and the estimated cost of EPA's preferred alternative is approximately $6 million.

ACE believes that the B.L. England boiler slag sold to MDC was a valuable material with various industrial applications and, therefore, the sale was not an arrangement for the disposal or treatment of any hazardous substances as would be necessary to constitute a basis for liability under CERCLA. ACE intends to contest any claims to the contrary made by EPA. In a May 2009 decision arising under CERCLA, which did not involve ACE, the U.S. Supreme Court rejected an EPA argument that the sale of a useful product constituted an arrangement for disposal or treatment of hazardous substances. While this decision supports ACE's position, at this time ACE cannot predict how EPA will proceed with respect to the Franklin Slag Pile site, or what portion, if any, of the Franklin Slag Pile site response costs EPA would seek to recover from ACE. Costs to resolve this matter are not expected to be material and are expensed as incurred.

Peck Iron and Metal Site

EPA informed Pepco in a May 2009 letter that Pepco may be a PRP under CERCLA with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that the Peck Iron and Metal scrap operations resulted in the improper storage and disposal of hazardous substances. EPA bases its allegation that Pepco arranged for disposal or treatment of hazardous substances sent to the site on information provided by former Peck Iron and Metal personnel, who informed EPA that Pepco was a customer at the site. Pepco has advised EPA by letter that its records show no evidence of any sale of scrap metal by Pepco to the site. Even if EPA has such records and such sales did occur, Pepco believes that any such scrap metal sales may be entitled to the recyclable material exemption from CERCLA liability. In a Federal Register notice published in November 2009, EPA placed the Peck Iron and Metal site on the National Priorities List. The National Priorities List, among other things, serves as a guide to EPA in determining which sites warrant further investigation to assess the nature and extent of the human health and environmental risks associated with a site. In September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Ward Transformer Site

In April 2009, a group of PRPs with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including Pepco, DPL and ACE, based on their alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including Pepco, DPL and ACE) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the Federal district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The Federal district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. PHI has concluded that a loss is reasonably possible with respect to this matter, but is unable to estimate an amount or range of reasonably possible losses to which it may be exposed. PHI does not believe that any of its three utility subsidiaries had extensive business transactions, if any, with the Ward Transformer site.

Benning Road Site

In September 2010, PHI received a letter from EPA identifying the Benning Road location, consisting of a generation facility formerly operated by Pepco Energy Services, and a transmission and distribution service center facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The generation facility was deactivated in June 2012 and the plant structures are currently in the process of being demolished, but the service center remains in operation. The principal contaminants of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. 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 with the District of Columbia Department of the Environment (DDOE), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DDOE's selection of a remedial action for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DDOE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

The final phase of field work consisting of the installation of monitoring wells and groundwater sampling and analysis began in May 2014. In addition, as part of the remaining RI field work and in conjunction with the power plant demolition activities, Pepco and Pepco Energy Services will be collecting soil samples adjacent to and beneath the concrete basins for the cooling towers previously dismantled and removed from the generating plant. On May 23, 2014, Pepco and DDOE filed a joint status report with the court in which the parties projected that the field work would be completed by the end of 2014. Once all of the field work has been completed, Pepco and Pepco Energy Services will prepare RI/FS reports for review and approval by DDOE after solicitation and consideration of public comment. The next status report to the court is due on May 25, 2015.

The remediation costs accrued for this matter are included in the table above in the columns entitled "Transmission and Distribution," "Legacy Generation – Regulated," and "Legacy Generation – Non-Regulated."

Indian River Oil Release

In 2001, DPL entered into a consent agreement with the Delaware Department of Natural Resources and Environmental Control for remediation, site restoration, natural resource damage compensatory projects and other costs associated with environmental contamination resulting from an oil release at the Indian River generating facility, which was sold in June 2001. The amount of remediation costs accrued for this matter is included in the table above in the column entitled "Legacy Generation – Regulated."

Potomac River Mineral Oil Release

In January 2011, a coupling failure on a transformer cooler pipe resulted in a release of non-toxic mineral oil at Pepco's Potomac River substation in Alexandria, Virginia. An overflow of an underground secondary containment reservoir resulted in approximately 4,500 gallons of mineral oil flowing into the Potomac River.

Beginning in March 2011, DDOE issued a series of compliance directives requiring Pepco to prepare an incident report, provide certain records, and prepare and implement plans for sampling surface water and river sediments and assessing ecological risks and natural resources damages. Pepco completed field sampling during the fourth quarter of 2011 and submitted sampling results to DDOE during the second quarter of 2012.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened enforcement action, including civil penalties, for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. In March 2014, Pepco and DDOE entered into a consent decree to resolve DDOE's threatened enforcement action, the terms of which include a combination of a civil penalty and a Supplemental Environmental Project (SEP) with a total cost to Pepco of $875,000. The consent decree was approved and entered by the District of Columbia Superior Court on April 4, 2014. In accordance with the consent decree, Pepco made a penalty payment to DDOE in the amount of $250,000 and made a donation in the amount of $25,000 to the Northeast Environmental Enforcement Training Fund, Inc., a non-profit organization that funds scholarships for environmental enforcement training. In addition, to implement the SEP, as required by the consent decree, Pepco entered into an agreement with Living Classrooms Foundation, Inc., a non-profit educational organization, to provide $600,000 to fund the design, installation and operation of a trash collection system at a storm water outfall that drains to the Anacostia River. Finally, the consent decree confirmed that no further actions are required by Pepco to investigate, assess or remediate impacts to the river from the mineral oil release. Discussions will proceed separately with DDOE and the federal resource trustees regarding the settlement of a natural resource damage (NRD) claim under federal law. Based on discussions to date, PHI and Pepco do not believe that the resolution of DDOE's enforcement action or the federal NRD claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the mineral oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility which involve pumping accumulated storm water to an above-ground holding tank for off-site disposal. In December 2011, Pepco completed the installation of a treatment system designed to allow automatic discharge of accumulated storm water from the secondary containment system. Pepco currently is seeking DDOE's and EPA's approval to commence operation of the new system on a pilot basis to demonstrate its effectiveness in meeting both secondary containment requirements and water quality standards related to the discharge of storm water from the facility. In the meantime, Pepco is continuing to use the aboveground holding tank to manage storm water from the secondary containment system. Pepco also is evaluating other technical and regulatory options for managing storm water from the secondary containment system as alternatives to the proposed treatment system discharge currently under discussion with EPA and DDOE.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Metal Bank Site

In the first quarter of 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted Pepco and DPL on behalf of itself and other federal and state trustees to request that Pepco and DPL execute a tolling agreement to facilitate settlement negotiations concerning natural resource damages allegedly caused by releases of hazardous substances, including polychlorinated biphenyls, at the Metal Bank Superfund Site located in Philadelphia, Pennsylvania. Pepco and DPL executed a tolling agreement, which has been extended to March 15, 2015, and will continue settlement discussions with the NOAA, the trustees and other PRPs.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Brandywine Fly Ash Disposal Site

In February 2013, Pepco received a letter from the Maryland Department of the Environment (MDE) requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by GenOn MD Ash Management, LLC (GenOn). In July 2013, while reserving its rights and related defenses under a 2000 asset purchase and sale agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

PHI and Pepco have determined that a loss associated with this matter for PHI and Pepco is probable and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately $3 million to $6 million. PHI and Pepco believe that the costs incurred in this matter will be recoverable from GenOn under the 2000 sale agreement.

The amount accrued for this matter is included in the table above in the column entitled “Transmission and Distribution.”

PHI’s Cross-Border Energy Lease Investments

As discussed in Note (18), “Discontinued Operations – Cross-Border Energy Lease Investments,” PHI held a portfolio of cross-border energy lease investments involving public utility assets located outside of the United States. Each of these investments was comprised of multiple leases and was structured as a sale and leaseback transaction commonly referred to by the IRS as a sale-in, lease-out, or SILO, transaction.

Since 2005, PHI’s cross-border energy lease investments have been under examination by the IRS as part of the PHI federal income tax audits. In connection with the audit of PHI’s 2001-2002 income tax returns, the IRS disallowed the depreciation and interest deductions in excess of rental income claimed by PHI for six of the eight lease investments and, in connection with the audits of PHI’s 2003-2005 and 2006-2008 income tax returns, the IRS disallowed such deductions in excess of rental income for all eight of the lease investments. In addition, the IRS has sought to recharacterize each of the leases as a loan transaction in each of the years under audit as to which PHI would be subject to original issue discount income. PHI has disagreed with the IRS’ proposed adjustments to the 2001-2008 income tax returns and has filed protests of these findings for each year with the Office of Appeals of the IRS. In November 2010, PHI entered into a settlement agreement with the IRS for the 2001 and 2002 tax years for the purpose of commencing litigation associated with this matter and subsequently filed refund claims in July 2011 for the disallowed tax deductions relating to the leases for these years. In January 2011, as part of this settlement, PHI paid $74 million of additional tax for 2001 and 2002, penalties of $1 million, and $28 million in interest associated with the disallowed deductions. Since the July 2011 refund claims were not approved by the IRS within the statutory six-month period, in January 2012 PHI filed complaints in the U.S. Court of Federal Claims seeking recovery of the tax payment, interest and penalties. The 2003-2005 and 2006-2011 income tax return audits continue to be in process with the IRS Office of Appeals and the IRS Exam Division, respectively, and are not presently a part of the U.S. Court of Federal Claims litigation.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison’s cross-border lease transaction. While PHI believes that its tax position with regard to its cross-border energy lease investments is appropriate, after analyzing the recent U.S. Court of Appeals ruling, PHI determined in the first quarter of 2013 that its tax position with respect to the tax benefits associated with the cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded a non-cash after-tax charge of $377 million in the first quarter of 2013 (as discussed in Note (18), “Discontinued Operations – Cross-Border Energy Lease Investments”), consisting of a charge to reduce the carrying value of the cross-border energy lease investments and a charge to reflect the anticipated additional interest expense related to changes in PHI’s estimated federal and state income tax obligations for the period over which the tax benefits ultimately may be disallowed. PHI had also previously made certain business assumptions regarding foreign investment opportunities available at the end of the full lease terms. During the first quarter of 2013, management believed that its conclusions regarding these business assumptions were no longer supportable, and the tax effects of this change in conclusion were included in the charge. While the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due, PHI believes that it is more likely than not that no such penalty will be incurred, and therefore no amount for any potential penalty has been recorded.

In the event that the IRS were to be successful in disallowing 100% of the tax benefits associated with these lease investments and recharacterize these lease investments as loans, PHI estimated that, as of March 31, 2013, it would have been obligated to pay approximately $192 million in additional federal taxes (net of the $74 million tax payment described above) and approximately $50 million of interest on the additional federal taxes. These amounts, totaling $242 million, were estimated after consideration of certain tax benefits arising from matters unrelated to the leases that would offset the taxes and interest due, including PHI's best estimate of the expected resolution of other uncertain and effectively settled tax positions, the carrying back and carrying forward of any existing net operating losses, and the application of certain amounts paid in advance to the IRS. In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made an advanced payment to the IRS of $242 million in the first quarter of 2013. This advanced payment was funded from currently available sources of liquidity and short-term borrowings. A portion of the proceeds from lease terminations (discussed in Note (18), "Discontinued Operations – Cross-Border Energy Lease Investments") was used to repay the short-term borrowings utilized to fund the advanced payment.

In order to mitigate the cost of continued litigation related to the cross-border energy lease investments, PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues for open tax years 2001 through 2011, including the cross-border energy lease issue. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014. If a settlement of all tax issues or a standalone settlement on the leases is not reached, PHI may move forward with its litigation with the IRS. Further discovery in the case is stayed until September 3, 2014, pursuant to an order issued by the court on July 1, 2014.

Third Party Guarantees, Indemnifications, and Off-Balance Sheet Arrangements

PHI and certain of its subsidiaries have various financial and performance guarantees and indemnification obligations that they have entered into in the normal course of business to facilitate commercial transactions with third parties as discussed below.

As of June 30, 2014, PHI and its subsidiaries were parties to a variety of agreements pursuant to which they were guarantors for standby letters of credit, energy procurement obligations, and other commitments and obligations. The commitments and obligations, in millions of dollars, were as follows:

	Guarantor				
	PHI	**Pepco**	**DPL**	**ACE**	**Total**
	(millions of dollars)				
Energy procurement obligations of Pepco Energy Services (a)	$ 4	$—	$—	$—	$ 4
Guarantees associated with disposal of Conectiv Energy assets (b)	13	—	—	—	13
Guaranteed lease residual values (c)	3	5	7	4	19
Total	$20	$ 5	$ 7	$ 4	$ 36

(a) PHI has continued contractual commitments for performance and related payments of Pepco Energy Services primarily to Independent System Operators and distribution companies.

(b) Represents guarantees by PHI of Conectiv Energy's derivatives portfolio transferred in connection with the disposition of Conectiv Energy's wholesale business. The derivative portfolio guarantee is currently $13 million and covers Conectiv Energy's performance prior to the assignment. This guarantee will remain in effect until the end of 2015.

(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $52 million, $10 million of which is a guaranty by PHI, $14 million by Pepco, $16 million by DPL and $12 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

PHI and certain of its subsidiaries have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These indemnification agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. Typically, claims may be made by third parties under these indemnification agreements over various periods of time depending on the nature of the claim. The maximum potential exposure under these indemnification agreements can range from a specified dollar amount to an unlimited amount depending on the nature of the claim and the particular transaction. The total maximum potential amount of future payments under these indemnification agreements is not estimable due to several factors, including uncertainty as to whether or when claims may be made under these indemnities.

Energy Savings Performance Contracts

Pepco Energy Services has a diverse portfolio of energy savings performance contracts that are associated with the installation of energy savings equipment or combined heat and power facilities for federal, state and local government customers. As part of the energy savings performance contracts, Pepco Energy Services typically guarantees that the equipment or systems it installs will generate a specified amount of energy savings on an annual basis over a multi-year period. As of June 30, 2014, the remaining notional amount of Pepco Energy Services' energy savings guarantees over the life of the multi-year performance contracts on: (i) completed projects was $252 million with the longest guarantee having a remaining term of 15 years; and, (ii) projects under construction was $205 million with the longest guarantee having a term of 23 years after completion of construction. On an annual basis, Pepco Energy Services undertakes a measurement and verification process to determine the amount of energy savings for the year and whether there is any shortfall in the annual energy savings compared to the guaranteed amount.

As of June 30, 2014, Pepco Energy Services had a performance guarantee contract associated with the production at a combined heat and power facility that is under construction totaling $15 million in notional value over 20 years.

Pepco Energy Services recognizes a liability for the value of the estimated energy savings or production shortfalls when it is probable that the guaranteed amounts will not be achieved and the amount is reasonably estimable. As of June 30, 2014, Pepco Energy Services had an accrued liability of $1 million for its energy savings contracts that it established during 2012. There was no significant change in the type of contracts issued during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013.

Dividends

On July 24, 2014, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable September 30, 2014, to stockholders of record on September 10, 2014.

(16) VARIABLE INTEREST ENTITIES

PHI is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if PHI or a subsidiary is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. PHI performs a qualitative analysis to determine whether a variable interest provides a controlling financial interest in any of its VIEs. Set forth below are the relationships with respect to which PHI conducted a VIE analysis as of June 30, 2014:

DPL Renewable Energy Transactions

DPL is subject to Renewable Energy Portfolio Standards (RPS) in the state of Delaware that require it to obtain renewable energy credits (RECs) for energy delivered to its customers. DPL's costs associated with obtaining RECs to fulfill its RPS obligations are recoverable from its customers by law. As of June 30, 2014, PHI, through its DPL subsidiary, is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 MWs, one solar PPA with a 10 MW facility, and an agreement with the Delaware Sustainable Energy Utility (DSEU) to purchase solar renewable energy credits (SREC). Each of the facilities associated with these PPAs is operational, and DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and SRECs from the solar facility and DSEU, up to certain amounts (as set forth below) at rates that are primarily fixed under the respective agreements. PHI and DPL have concluded that while VIEs exist under these contracts, consolidation is not required under the FASB guidance on the consolidation of variable interest entities as DPL is not the primary beneficiary. DPL has not provided financial or other support under these arrangements that it was not previously contractually required to provide during the periods presented, nor does DPL have any intention to provide such additional support.

Because DPL has no equity or debt interest in these renewable energy transactions, the maximum exposure to loss relates primarily to any above-market costs incurred for power, RECs or SRECs. Due to unpredictability in the amount of MW's ultimately purchased under the agreements for purchased renewable energy, RECs and SRECs, PHI and DPL are unable to quantify the maximum exposure to loss. The power purchase, REC and SREC costs are recoverable from DPL's customers through regulated rates.

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from the second wind facility through 2031 in amounts not to exceed 40 MWs, and from the third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's aggregate purchases under the three wind PPAs totaled $7 million for each of the three months ended June 30, 2014 and 2013. DPL's aggregate purchases under the three wind PPAs totaled $17 million for each of the six months ended June 30, 2014 and 2013.

The term of the agreement with the solar facility is through 2030 and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. The DSEU may enter into 20-year contracts with solar facilities to purchase SRECs for resale to DPL. Under the agreement, DPL is obligated to purchase SRECs in amounts not to exceed 19 MWs at annually determined auction rates. DPL's purchases under these solar agreements were $1 million and less than $1 million for the three months ended June 30, 2014 and 2013, respectively. DPL's purchases under these solar agreements were $2 million and less than $1 million for the six months ended June 30, 2014 and 2013, respectively.

On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to fuel cell facilities totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL would be an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour of energy produced by the fuel cell facilities through 2033. DPL has no obligation to the qualified fuel cell provider other than to remit payments collected from its distribution customers pursuant to the tariff. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. At June 30, 2014 and 2013, 30 MWs and 15 MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $9 million and $3 million to distribution customers for the three months ended June 30, 2014 and 2013, respectively. DPL billed $18 million and $6 million to distribution customers for the six months ended June 30, 2014 and 2013, respectively. PHI and DPL have concluded that while a VIE exists under this arrangement, consolidation is not required for this arrangement under the FASB guidance on consolidation of variable interest entities as DPL is not the primary beneficiary.

ACE Power Purchase Agreements

PHI, through its ACE subsidiary, is a party to three PPAs with unaffiliated NUGs totaling 459 MWs. One of the agreements ends in 2016 and the other two end in 2024. PHI and ACE were not involved in the creation of these contracts and have no equity or debt invested in these entities. In performing its VIE analysis, PHI has been unable to obtain sufficient information to determine whether these three entities were variable interest entities or if ACE was the primary beneficiary. As a result, PHI has applied the scope exemption from the consolidation guidance.

Because ACE has no equity or debt invested in the NUGs, the maximum exposure to loss relates primarily to any above-market costs incurred for power. Due to unpredictability in the PPAs pricing for purchased energy, PHI and ACE are unable to quantify the maximum exposure to loss. The power purchase costs are recoverable from ACE's customers through regulated rates. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the three months ended June 30, 2014 and 2013, were approximately $54 million and $53 million, respectively, of which approximately $49 million and $48 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the six months ended June 30, 2014 and 2013, were approximately $126 million and $107 million, respectively, of which approximately $108 million and $103 million, respectively, consisted of power purchases under the PPAs.

ACE Funding

In 2001, ACE established ACE Funding solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. The proceeds of the sale of each series of Transition Bonds were transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect a non-bypassable Transition Bond Charge (representing revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees) from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on the Transition Bonds and related taxes, expenses and fees (Bondable Transition Property). The assets of ACE Funding, including the Bondable Transition Property, and the Transition Bond Charges collected from ACE's customers, are not available to creditors of ACE. The holders of Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding, and PHI and ACE consolidate ACE Funding in their consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

(17) ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of Pepco Holdings' AOCL relating to continuing and discontinued operations are as follows. For additional information, see the consolidated statements of comprehensive income.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Balance at beginning of period	$ (33)	$ (42)	$ (34)	$ (48)
Treasury Lock				
Balance at beginning of period	(9)	(10)	(9)	(10)
Amount of pre-tax loss reclassified to Interest expense	—	1	—	1
Income tax benefit	—	—	—	—
Balance at end of period	(9)	(9)	(9)	(9)
Pension and Other Postretirement Benefits				
Balance at beginning of period	(24)	(31)	(25)	(32)
Amount of amortization of net prior service cost and actuarial loss reclassified to Other operation and maintenance expense	(3)	(1)	(2)	1
Income tax expense (benefit)	1	—	1	(1)
Balance at end of period	(26)	(32)	(26)	(32)
Commodity Derivatives				
Balance at beginning of period	—	(1)	—	(6)
Amount of net pre-tax loss reclassified to loss from discontinued operations before income tax	—	1	—	10
Income tax benefit	—	—	—	(4)
Balance at end of period	—	—	—	—
Balance as of June 30	$ (35)	$ (41)	$ (35)	$ (41)

(18) DISCONTINUED OPERATIONS

PHI's loss from discontinued operations, net of income taxes, is comprised of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Cross-border energy lease investments	$ —	$ (15)	$ —	$ (334)
Pepco Energy Services' retail electric and natural gas supply businesses	—	4	—	4
Loss from discontinued operations, net of income taxes	$ —	$ (11)	$ —	$ (330)

Cross-Border Energy Lease Investments

Between 1994 and 2002, PCI entered into cross-border energy lease investments consisting of hydroelectric generation facilities, coal-fired electric generation facilities and natural gas distribution networks located outside of the United States. Each of these lease investments was structured as a sale and leaseback transaction commonly referred to as a sale-in, lease-out, or SILO, transaction. During the second and third quarters of 2013, PHI terminated early all of its interests in the remaining lease investments. PHI received aggregate net cash proceeds from these early terminations of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. As a result, PHI has reported the results of operations of the cross-border energy lease investments as discontinued operations in all periods presented in the accompanying consolidated statements of income (loss).

Operating Results

The operating results for the cross-border energy lease investments were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Operating revenue from PHI's cross-border energy lease investments	$ —	$ 2	$ —	$ 7
Non-cash charge to reduce carrying value of PHI's cross-border energy lease investments	—	—	—	(373)
Total operating revenue	$ —	$ 2	$ —	$ (366)
Income from operations of discontinued operations, net of income taxes (a)	$ —	$ (6)	$ —	$ (325)
Net losses associated with the early termination of the cross-border energy lease investments, net of income taxes (b)	—	(9)	—	(9)
Loss from discontinued operations, net of income taxes	$ —	$ (15)	$ —	$ (334)

(a) Includes income tax expense (benefit) of approximately zero and $5 million for the three months ended June 30, 2014 and 2013, respectively, and zero and $(43) million for the six months ended June 30, 2014 and 2013, respectively.

(b) Includes income tax benefit of approximately zero and $5 million for the three months ended June 30, 2014 and 2013, respectively, and zero and $5 million for the six months ended June 30, 2014 and 2013, respectively.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that its tax position with respect to the benefits associated with its cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes, and PHI recorded non-cash charges of $323 million (after-tax) in the first quarter of 2013 and $6 million (after-tax) in the second quarter of 2013, consisting of the following components:

- A non-cash pre-tax charge of $373 million ($313 million after-tax) to reduce the carrying value of these cross-border energy lease investments under FASB guidance on leases (ASC 840). This pre-tax charge was originally recorded in the consolidated statements of income (loss) as a reduction in operating revenue and is now reflected in loss from discontinued operations, net of income taxes.
- A non-cash charge of $16 million after-tax to reflect the anticipated additional net interest expense under FASB guidance for income taxes (ASC 740) related to estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed. This after-tax charge was originally recorded in the consolidated statements of income (loss) as an increase in income tax expense and is now reflected in loss from discontinued operations, net of income taxes. The after-tax interest charge for PHI on a consolidated basis was $70 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in the recognition of a $12 million interest benefit for the Power Delivery segment, and interest expense of $16 million for PCI and $66 million for Corporate and Other, respectively.

PHI had also previously made certain business assumptions regarding foreign investment opportunities available at the end of the full lease terms. In view of the change in PHI's tax position with respect to the tax benefits associated with the cross-border energy lease investments and PHI's resulting decision to pursue the early termination of these investments, management concluded in the first quarter of 2013 that these business assumptions were no longer supportable and the tax effects of this conclusion were reflected in the after-tax charge of $313 million described above.

PHI accrued no penalties associated with its re-assessment of the likely outcome of tax positions associated with the cross-border energy lease investments. While the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due, PHI believes that it is more likely than not that no such penalty will be incurred, and therefore no amount for any potential penalty was included in the charge.

For additional information concerning these cross-border energy lease investments, see Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments."

Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services

On March 21, 2013, Pepco Energy Services entered into an agreement whereby a third party assumed all the rights and obligations of the remaining natural gas supply customer contracts, and the associated supply obligations, inventory and derivative contracts. The transaction was completed on April 1, 2013. In addition, in the second quarter of 2013, Pepco Energy Services completed the wind-down of its retail electric supply business by terminating its remaining customer supply and wholesale purchase obligations beyond June 30, 2013. As a result, PHI has reported the results of operations of Pepco Energy Services' retail electric and natural gas supply businesses as discontinued operations in all periods presented in the accompanying consolidated statements of income (loss).

Operating Results

The operating results for the retail electric and natural gas supply businesses of Pepco Energy Services are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Operating revenue	$ —	$ 34	$ —	$ 84
Income from operations of discontinued operations, net of income taxes (a)	$ —	$ 1	$ —	$ 3
Net gains associated with accelerated disposition of retail electric and natural gas contracts, net of income taxes (b)	—	3	—	1
Income from discontinued operations, net of income taxes	$ —	$ 4	$ —	$ 4

(a) Includes income tax expense of zero for each of the three months ended June 30, 2014 and 2013, and zero and $1 million for the six months ended June 30, 2014 and 2013, respectively.
(b) Includes income tax expense of zero and $1 million for the three months ended June 30, 2014 and 2013, respectively, and zero for each of the six months ended June 30, 2014 and 2013.

Derivative Instruments and Hedging Activities

Derivatives were used by the retail electric and natural gas supply businesses of Pepco Energy Services to hedge commodity price risk. There were no outstanding forward contracts or derivative positions for Pepco Energy Services as of June 30, 2014 and December 31, 2013.

As of June 30, 2014, Pepco Energy Services had posted net cash collateral of $2 million. As December 31, 2013, Pepco Energy Services had posted net cash collateral of $3 million and letters of credit of less than $1 million.

Derivatives Designated as Hedging Instruments

At December 31, 2012, the cumulative net pre-tax loss related to effective cash flow hedges of the retail electric and natural gas supply businesses of Pepco Energy Services included in AOCL was $10 million ($6 million after-tax). With the assumption by a third party, on April 1, 2013, of all the rights and obligations of the derivative contracts associated with the retail natural gas supply business, PHI determined that the hedged forecasted purchases of supply for retail natural gas customers were probable not to occur. Accordingly, during the first quarter of 2013, PHI recognized $4 million of pre-tax unrealized derivative losses ($2 million after-tax) that were previously included in AOCL as cash flow hedges. The remaining pre-tax loss was reclassified into income on completion of the wind-down of the retail electric business in the second quarter of 2013.

Other Derivative Activity

The retail electric and natural gas supply businesses of Pepco Energy Services held certain derivatives that were not in hedge accounting relationships and were not designated as normal purchases or normal sales. These derivatives were recorded at fair value on the balance sheet with the gain or loss for changes in fair value recorded through Income (loss) from discontinued operations, net of income taxes.

For the three and six months ended June 30, 2014 and 2013, the amount of the derivative gain (loss) for the retail electric and natural gas supply businesses of Pepco Energy Services recognized in Income (loss) from discontinued operations, net of income taxes is provided in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Reclassification of mark-to-market to realized on settlement of contracts	$ —	$ 5	$ —	$ 10
Unrealized mark-to-market loss	—	—	—	—
Total net gain (loss)	$ —	$ 5	$ —	$ 10

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
	(millions of dollars)			
Operating Revenue	$ 508	$ 469	$ 1,043	$ 946
Operating Expenses				
Purchased energy	177	157	407	349
Other operation and maintenance	91	95	184	197
Depreciation and amortization	56	49	112	96
Other taxes	90	88	180	177
Total Operating Expenses	414	389	883	819
Operating Income	94	80	160	127
Other Income (Expenses)				
Interest expense	(30)	(28)	(57)	(54)
Other income	10	5	19	9
Total Other Expenses	(20)	(23)	(38)	(45)
Income Before Income Tax Expense	74	57	122	82
Income Tax Expense	28	20	44	22
Net Income	$ 46	$ 37	$ 78	$ 60

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 27	$ 9
Restricted cash equivalents	7	3
Accounts receivable, less allowance for uncollectible accounts of $18 million and $16 million, respectively	342	345
Inventories	67	67
Deferred income tax assets, net	48	48
Income taxes and related accrued interest receivable	94	113
Prepaid expenses and other	8	18
Total Current Assets	593	603
OTHER ASSETS		
Regulatory assets	595	563
Prepaid pension expense	324	332
Investment in trust	32	33
Income taxes and related accrued interest receivable	28	36
Other	74	66
Total Other Assets	1,053	1,030
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	7,527	7,310
Accumulated depreciation	(2,810)	(2,772)
Net Property, Plant and Equipment	4,717	4,538
TOTAL ASSETS	$ 6,363	$ 6,171

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ —	$ 151
Current portion of long-term debt and project funding	5	175
Accounts payable	100	132
Accrued liabilities	106	90
Accounts payable due to associated companies	29	32
Capital lease obligations due within one year	10	9
Taxes accrued	26	34
Interest accrued	22	20
Liabilities and accrued interest related to uncertain tax positions	—	37
Customer deposits	46	46
Other	80	75
Total Current Liabilities	424	801
DEFERRED CREDITS		
Regulatory liabilities	112	113
Deferred income tax liabilities, net	1,488	1,412
Investment tax credits	3	3
Other postretirement benefit obligations	59	61
Liabilities and accrued interest related to uncertain tax positions	—	10
Other	65	65
Total Deferred Credits	1,727	1,664
OTHER LONG-TERM LIABILITIES		
Long-term debt	2,123	1,724
Capital lease obligations	55	60
Total Other Long-Term Liabilities	2,178	1,784
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
EQUITY		
Common stock, $.01 par value, 200,000,000 shares authorized, 100 shares outstanding	—	—
Premium on stock and other capital contributions	1,010	930
Retained earnings	1,024	992
Total Equity	2,034	1,922
TOTAL LIABILITIES AND EQUITY	$ 6,363	$ 6,171

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 78	$ 60
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	112	96
Gains on sales of land	(8)	—
Deferred income taxes	68	46
Changes in:		
Accounts receivable	—	(18)
Inventories	—	(3)
Prepaid expenses	10	13
Regulatory assets and liabilities, net	(61)	(49)
Accounts payable and accrued liabilities	(28)	(22)
Prepaid pension expense, excluding contributions	8	10
Income tax-related prepayments, receivables and payables	(29)	(55)
Interest accrued	2	3
Other assets and liabilities	(3)	(2)
Net Cash From Operating Activities	149	79
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(241)	(258)
Department of Energy capital reimbursement awards received	3	12
Proceeds from sale of assets	8	—
Changes in restricted cash equivalents	(4)	(3)
Net other investing activities	1	(4)
Net Cash Used By Investing Activities	(233)	(253)
FINANCING ACTIVITIES		
Dividends paid to Parent	(46)	(15)
Capital contribution from Parent	80	175
Issuance of long-term debt	404	250
Reacquisitions of long-term debt	(175)	—
Repayments of short-term debt, net	(151)	(231)
Cost of issuances	(7)	(4)
Net other financing activities	(3)	(4)
Net Cash From Financing Activities	102	171
Net Increase (Decrease) in Cash and Cash Equivalents	18	(3)
Cash and Cash Equivalents at Beginning of Period	9	9
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 27	$ 6
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ (2)	$ —

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
BALANCE, DECEMBER 31, 2013	100	$ —	$ 930	$ 992	$1,922
Net Income	—	—	—	32	32
Capital contribution from Parent	—	—	80	—	80
BALANCE, MARCH 31, 2014	100	—	1,010	1,024	2,034
Net Income	—	—	—	46	46
Dividends on common stock	—	—	—	(46)	(46)
BALANCE, JUNE 30, 2014	100	$ —	$ 1,010	$ 1,024	$2,034

The accompanying Notes are an integral part of these Financial Statements.

NOTES TO FINANCIAL STATEMENTS

POTOMAC ELECTRIC POWER COMPANY

(1) ORGANIZATION

Potomac Electric Power Company (Pepco) is engaged in the transmission and distribution of electricity in the District of Columbia and major portions of Prince George's County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territories who do not elect to purchase electricity from a competitive supplier. Default Electricity Supply is known as Standard Offer Service in both the District of Columbia and Maryland. Pepco is a wholly owned subsidiary of Pepco Holdings, Inc. (Pepco Holdings or PHI).

PHI has entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly-owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly-owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly-owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly-owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement on July 29, 2014, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission, the Delaware Public Service Commission, the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976; and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). The parties currently anticipate that the closing will occur in the second or third quarter of 2015.

The Merger Agreement may be terminated by each of PHI and Exelon under certain circumstances, including if the Merger is not consummated by July 29, 2015 (subject to extension to October 29, 2015, if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for both PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals (a Regulatory Termination), Exelon will pay PHI a reverse termination fee equal to the purchase price paid up to the date of termination by Exelon to purchase the Preferred Stock, through PHI's redemption of the Preferred Stock for nominal consideration. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

Pepco's unaudited financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been omitted. Therefore, these financial statements should be read along with the annual financial statements included in Pepco's annual report on Form 10-K for the year ended December 31, 2013. In the opinion of Pepco's management, the unaudited financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly Pepco's financial condition as of June 30, 2014, in accordance with GAAP. The year-end December 31, 2013 balance sheet included herein was derived from audited financial statements, but does not include all disclosures required by GAAP. Interim results for the three and six months ended June 30, 2014 may not be indicative of results that will be realized for the full year ending December 31, 2014.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the financial statements and accompanying notes. Although Pepco believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset impairment evaluations, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of loss contingency liabilities for general litigation and auto and other liability claims and income tax provisions and reserves. Additionally, Pepco is subject to legal, regulatory, and other proceedings and claims that arise in the ordinary course of its business. Pepco records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco's gross revenues were $74 million and $77 million for the three months ended June 30, 2014 and 2013, respectively, and $152 million and $153 million for the six months ended June 30, 2014 and 2013, respectively.

Reclassifications

Certain prior period amounts have been reclassified in order to conform to the current period presentation.

Revision of Prior Period Financial Statements

Operating and Financing Cash Flows

The statement of cash flows for the six months ended June 30, 2013 has been revised to correctly present changes in book overdraft balances as operating activities (included in Changes in accounts payable and accrued liabilities) rather than financing activities (included in Net other financing activities). For the six months ended June 30, 2013, the effect of the revision was to decrease Net cash from operating activities by $5 million from $84 million to $79 million, and increase Net cash from financing activities by $5 million from $166 million to $171 million. The revision was not considered to be material, individually or in the aggregate, to previously issued financial statements.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Liabilities (Accounting Standards Codification (ASC) 405)

In February 2013, the Financial Accounting Standards Board (FASB) issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, Pepco is required to measure such obligations as the sum of the amount it agreed to pay on the basis of its arrangement among co-obligors and any additional amount it expects to pay on behalf of its co-obligors. Adoption of this guidance during the first quarter of 2014 did not have a material impact on Pepco's financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance requiring netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The prospective adoption of this guidance at March 31, 2014 resulted in Pepco netting liabilities related to uncertain tax positions with deferred tax assets for net operating loss and other carryforwards (included in deferred income tax liabilities, net) and income taxes receivable (including income tax deposits) related to effectively settled uncertain tax positions.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements are effective for Pepco beginning January 1, 2017, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2017. Early adoption is not permitted. Pepco is currently evaluating the potential impact of this new guidance on its financial statements and which implementation approach to select.

(5) SEGMENT INFORMATION

Pepco operates its business as one regulated utility segment, which includes all of its services as described above.

(6) REGULATORY MATTERS

Rate Proceedings

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings as indicated below.

Bill Stabilization Adjustment

Pepco proposed in each of its respective jurisdictions the adoption of a bill stabilization adjustment (BSA) mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. The BSA proposal has been approved and implemented for Pepco electric service in Maryland and in the District of Columbia.

Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission.

District of Columbia

On March 8, 2013, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by approximately \$52.1 million (adjusted by Pepco to approximately \$44.8 million on December 3, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. On March 26, 2014, the DCPSC issued an order approving an increase in base rates of approximately \$23.4 million, based on an ROE of 9.40%. The new rates became effective on April 16, 2014. On April 28, 2014, Pepco filed an application for reconsideration or clarification of the DCPSC's March 26, 2014 order, contesting several of the reporting obligations and other directives imposed by the order. On April 29, 2014, the other parties to the proceeding filed applications for reconsideration of the March 26, 2014 order, which generally challenge Pepco's post-test year reliability projects, the adequacy of Pepco's environmental and efficiency measures, and the structure of Pepco's residential aid discount rate. On July 10, 2014, the DCPSC issued its order on reconsideration, which granted in part and denied in part Pepco's application for reconsideration with regard to reporting obligations. The DCPSC also rejected the other parties' applications for reconsideration challenging Pepco's recovery for several post-test year reliability projects. Under the Merger Agreement, Pepco is permitted to continue to pursue action in this matter to its conclusion, but Pepco is not permitted to initiate or file further electric distribution base rate cases in the District of Columbia without Exelon's consent.

Maryland

Pepco Electric Distribution Base Rates

In December 2011, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently adjusted by Pepco to approximately $66.2 million), based on a requested ROE of 10.75%. In July 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. Among other things, the order also authorized Pepco to recover the actual cost of advanced metering infrastructure (AMI) meters installed during the 2011 test year, stating that cost recovery for AMI deployment will be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new rates became effective on July 20, 2012. The Maryland Office of People's Counsel (OPC) has sought rehearing on the portion of the order allowing Pepco to recover the costs of AMI meters installed during the test year; that motion remains pending.

On November 30, 2012, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $60.8 million, based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. Pepco also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $192 million associated with its plan to accelerate investments in infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force. Specific projects under Pepco's Grid Resiliency Charge plan included acceleration of its tree-trimming cycle, upgrade of 12 additional feeders per year for two years and undergrounding of six distribution feeders. In addition, Pepco proposed a reliability performance-based mechanism that would allow Pepco to earn up to $1 million as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $1 million in total if Pepco does not meet at least the minimum reliability performance targets. Pepco requested that any credits/charges would flow through the proposed Grid Resiliency Charge rider.

On July 12, 2013, the MPSC issued an order related to Pepco's November 30, 2012 application approving an annual rate increase of approximately $27.9 million, based on an ROE of 9.36%. The order provides for the full recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by including the related capital costs in the rate base and amortizing the related deferred operation and maintenance expenses of $23.6 million over a five-year period. The order excludes the cost of AMI meters from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system; as a result, costs for AMI meters incurred with respect to the 2012 test year and beyond will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system that are deferred and on which a carrying charge is deferred, but only until such cost effectiveness has been demonstrated and such costs are included in rates. However, the MPSC's July 2012 order in Pepco's previous electric distribution base rate case, which allowed Pepco to recover the costs of meters installed during the 2011 test year for that case, remains in effect, and the Maryland OPC's motion for rehearing in that case remains pending.

The order also approved a Grid Resiliency Charge, which went into effect on January 1, 2014, for recovery of costs totaling approximately $24.0 million associated with Pepco's proposed plan to accelerate investments related to certain priority feeders, provided that, before implementing the surcharge, Pepco (i) provides additional information to the MPSC related to performance objectives, milestones and costs, and (ii) makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for each following year. The MPSC did not approve the proposed acceleration of the tree-trimming cycle or the undergrounding of six distribution feeders. The MPSC also rejected Pepco's proposed reliability performance-based mechanism. The new rates were effective on July 12, 2013.

On July 26, 2013, Pepco filed a notice of appeal of the July 12, 2013 order in the Circuit Court for the City of Baltimore. Other parties also have filed notices of appeal, which have been consolidated with Pepco's appeal. In its memorandum filed with the appeals court, Pepco asserts that the MPSC erred in failing to grant Pepco an adequate ROE, denying a number of other cost recovery mechanisms and limiting Pepco's test year data to no more than four months of forecasted data in future rate cases. The memoranda filed with the appeals court by the other parties primarily assert that the MPSC erred or acted arbitrarily and capriciously in allowing the recovery of certain costs by Pepco and refusing to reduce Pepco's rate base by known and measurable accumulated depreciation. The appeal remains pending.

On December 4, 2013, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $43.3 million (adjusted by Pepco to approximately $37.4 million on April 15, 2014), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. On July 2, 2014, the MPSC issued an order related to Pepco's December 2013 application approving an annual rate increase of approximately $8.75 million, based on an ROE of 9.62%. The new rates became effective on July 4, 2014.

Under the Merger Agreement, Pepco is permitted, and intends to continue, to pursue the conclusion of the aforementioned matters, but under the Merger Agreement, Pepco is not permitted to initiate or file further electric distribution base rate cases in Maryland without Exelon's consent.

Federal Energy Regulatory Commission

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc., filed a joint complaint with FERC against Pepco and its affiliates Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for Pepco and its utility affiliates is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. Pepco believes the allegations in this complaint are without merit and is vigorously contesting it. In April 2013, Pepco filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that the complaint failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. Pepco cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, Pepco is permitted, and intends to continue, to pursue the conclusion of this matter.

On June 19, 2014, FERC issued an order in a proceeding in which Pepco was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint filed against Pepco and its utility affiliates, Pepco believes that it is probable that FERC will direct Pepco to use this methodology at the time it issues an order addressing the complaint. As a result, Pepco applied an estimated ROE based on the two-step methodology announced by FERC for the period over which Pepco's transmission revenues would be subject to refund as a result of the challenge, and has recorded an estimated reserve in the second quarter of 2014 related to this matter.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland. In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 megawatts (MWs) beginning in 2015. The order requires Pepco, its affiliate DPL and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative standard offer service (SOS) loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs' concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that each of the Contract EDCs will recover its costs associated with the contract through surcharges on its respective SOS customers.

In April 2012, a group of generating companies operating in the PJM Interconnection, LLC (PJM) region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC's order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. The Maryland circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, Pepco entered into a contract in accordance with the terms of the MPSC's order; however, under the contract's terms, it will not become effective, if at all, until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit. On June 2, 2014, the Fourth Circuit issued a decision affirming the lower Federal court judgment. On June 16, 2014, both the winning bidder and the MPSC sought rehearing of the Fourth Circuit's decision. On June 30, 2014, the Fourth Circuit denied the rehearing requests of the winning bidder and the MPSC. On July 8, 2014, the Fourth Circuit issued its mandate stating that its decision takes effect on that date, which means that the parties have until September 29, 2014 to appeal the Fourth Circuit's decision to the U.S. Supreme Court. The appeal to the Maryland Court of Special Appeals remains pending.

On June 2, 2014, the winning bidder filed the contracts at FERC requesting that they be accepted pursuant to Section 205 of the Federal Power Act. The Contract EDCs intervened in the proceeding and requested that the winning bidder's filing be rejected on the grounds that the contracts never came into effect.

Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, Pepco continues to believe that it may be required to record its proportional share of the contracts as a derivative instrument at fair value and record a related regulatory asset of approximately the same amount because Pepco would recover any payments under the contracts from SOS customers. Pepco has concluded that any accounting for these contracts would not be required until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

Pepco continues to evaluate these proceedings to determine, should the contracts be found to be valid and enforceable, (i) the extent of the negative effect that the contracts may have on Pepco's credit metrics, as calculated by independent rating agencies that evaluate and rate Pepco and its debt issuances, (ii) the effect on Pepco's ability to recover its associated costs of the contracts if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contracts on the financial condition, results of operations and cash flows of Pepco.

District of Columbia Power Line Undergrounding Initiative

In August 2012, the District of Columbia mayor issued an Executive Order establishing the Mayor's Power Line Undergrounding Task Force (the DC Undergrounding Task Force). The stated purpose of the DC Undergrounding Task Force was to pool the collective resources available in the District of Columbia to produce an analysis of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead distribution facilities in the District of Columbia. These resources included legislative bodies, regulators, utility personnel, experts and other parties who could contribute in a meaningful way to the DC Undergrounding Task Force. In October 2013, the DC Undergrounding Task Force issued a Final Report of its findings and recommendations endorsing a $1 billion initiative to selectively place underground some of the District of Columbia's most outage-prone power lines, which lines and surrounding conduit would be owned and maintained by Pepco. The initiative is known as the District of Columbia Power Line Undergrounding (or DC PLUG) initiative.

The legislation providing for implementation of the Final Report's recommendations contemplates that: (i) Pepco will fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost will be financed by the District of Columbia's issuance of securitized bonds, which bonds will be repaid through a surcharge on the electric bills of Pepco District of Columbia customers that Pepco will remit to the District of Columbia; and (iii) the remaining amount will be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount. The enabling legislation, entitled the Electric Company Infrastructure Improvement Financing Act of 2013 (the Improvement Financing Act), became effective on May 3, 2014. The application for the financing order will be filed by Pepco with the DCPSC in August 2014. The final steps in the approval process are DCPSC authorization of the DC PLUG Application and Triennial Plan filed by Pepco and DDOT on June 17, 2014, and DCPSC issuance of a financing order as required by the Improvement Financing Act. These approvals would permit (i) Pepco and DDOT to commence their proposed construction plan; (ii) the District of Columbia to issue the necessary bonds to fund the District of Columbia's portion of the DC PLUG initiative; and (iii) the establishment of the customer surcharges contemplated by the Improvement Financing Act. The DCPSC's orders are anticipated in the fourth quarter of 2014. Under the Merger Agreement, Pepco is permitted, and intends to continue, to pursue the DC PLUG initiative.

MAPP Settlement Agreement

In February 2014, FERC issued an order approving the settlement agreement submitted by Pepco in connection with Pepco's proceeding seeking recovery of approximately $50 million in abandonment costs related to the Mid-Atlantic Power Pathway (MAPP) project. Pepco had been directed by PJM to construct the MAPP project, a 152-mile high-voltage interstate transmission line, and was subsequently directed by PJM to cancel it. The abandonment costs sought for recovery were subsequently reduced to $45 million from write-offs of certain disallowed costs in 2013 and transfers of materials to inventories for use on other projects. Under the terms of the FERC-approved settlement agreement, Pepco will receive approximately $43.9 million of transmission revenues over a three-year period, which began on June 1, 2013, and will retain title to all real property and property rights acquired in connection with the MAPP project, which had an estimated fair value of $2 million. The FERC-approved settlement agreement resolves all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project, and the terms of the settlement agreement are not subject to modification through any other FERC proceeding. As of June 30, 2014, Pepco had a regulatory asset related to the MAPP abandonment costs of approximately $27 million, net of amortization, and land of $2 million. Pepco does not expect to recognize any further pre-tax income related to the MAPP abandonment costs.

Merger Approval Proceedings

District of Columbia

On June 18, 2014, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application with the DCPSC seeking approval of the Merger. To approve the Merger, the DCPSC must find that the Merger is in the public interest. In an order issued June 27, 2014, the DCPSC stated that to make the determination of whether the transaction is in the public interest, it will analyze the transaction in the context of six factors to determine whether the transaction balances the interests of shareholders and investors with ratepayers and the community, whether the benefits to shareholders do or do not come at the expense of the ratepayers, and whether the transaction produces a direct and tangible benefit to ratepayers. The six factors identified by the DCPSC are the effects of the transaction on: (i) ratepayers, shareholders, the financial health of the utility standing alone and as merged, and the local economy; (ii) utility management and administrative operations; (iii) the safety and reliability of services; (iv) risks associated with nuclear operations; (v) the DCPSC's ability to regulate the new utility effectively; and (vi) competition in the local utility market. The law of the District of Columbia does not impose any time limit on the DCPSC's review of the Merger, and a procedural schedule for this proceeding has not yet been set.

Maryland

Approval of the Merger by the MPSC is required, but the application for approval of the Merger has not yet been filed. Maryland law requires the MPSC to approve a merger subject to its review if it finds that the merger is consistent with the public interest, convenience and necessity, including its benefits to and impact on consumers. In making this determination, the MPSC is required to consider the following 12 criteria: (i) the potential impact of the merger on rates and charges paid by customers and on the services and conditions of operation of the utility; (ii) the potential impact of the merger on continuing investment needs for the maintenance of utility services, plant and related infrastructure; (iii) the proposed capital structure that will result from the merger, including allocation of earnings from the utility; (iv) the potential effects on employment by the utility; (v) the projected allocation between the utility's shareholders and ratepayers of any savings that are expected; (vi) issues of reliability, quality of service and quality of customer service; (vii) the potential impact of the merger on community investment; (viii) affiliate and cross-subsidization issues; (ix) the use or pledge of utility assets for the benefit of an affiliate; (x) jurisdictional and choice-of-law issues; (xi) whether it is necessary to revise the MPSC's ring-fencing and affiliate code of conduct regulations in light of the merger; and (xii) any other issues the MPSC considers relevant to the assessment of the merger. Once the application is filed, the MPSC is required to issue an order within 180 days. However, the MPSC can grant a 45-day extension for good cause. If no order is issued by the statutory deadline, then the Merger would be deemed to be approved. Pepco anticipates filing the merger approval application with the MPSC in the third quarter of 2014.

Virginia

On June 3, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, filed an application with the VSCC seeking approval of the Merger. Virginia law provides that, if the VSCC determines, with or without hearing, that adequate service to the public at just and reasonable rates will not be impaired or jeopardized by granting the application for approval, then the VSCC shall approve a merger with such conditions that the VSCC deems to be appropriate in order to satisfy this standard. The VSCC is required to rule on the application within 60 days, which may be extended by up to 120 days. On June 16, 2014, the VSCC issued an order extending the time period for issuing a decision by an additional 60 days, to October 1, 2014.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the Federal Power Act. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. The companies requested that FERC find that the transaction is consistent with the public interest and grant approval within 90 days.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

Pepco accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and its other postretirement benefits plan (the Pepco Holdings, Inc. Welfare Plan for Retirees), as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended June 30, 2014 and 2013, before intercompany allocations from the PHI Service Company, were $10 million and $29 million, respectively. Pepco's allocated share was $4 million and $11 million, respectively, for the three months ended June 30, 2014 and 2013. PHI's pension and other postretirement net periodic benefit cost for the six months ended June 30, 2014 and 2013, before intercompany allocations from the PHI Service Company, were $28 million and $54 million, respectively. Pepco's allocated share was $11 million and $19 million, respectively, for the six months ended June 30, 2014 and 2013.

In 2014 and 2013, Pepco made no contributions to the PHI Retirement Plan.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and became effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $18 million reduction in Pepco's net periodic benefit cost for other postretirement benefits during the six months ended June 30, 2014 when compared to the six months ended June 30, 2013. Pepco anticipates approximately 37% of annual net periodic other postretirement benefit costs will be capitalized.

(8) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility is currently August 1, 2018.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million and the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of June 30, 2014.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of June 30, 2014 and December 31, 2013, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $736 million and $332 million, respectively. Pepco's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by DPL and ACE and the portion of the total capacity being used by PHI.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings.

Commercial Paper

Pepco maintains an on-going commercial paper program to address its short-term liquidity needs. As of June 30, 2014, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

Pepco had no commercial paper outstanding at June 30, 2014. The weighted average interest rate for commercial paper issued by Pepco during the six months ended June 30, 2014 was 0.27% and the weighted average maturity of all commercial paper issued by Pepco during the six months ended June 30, 2014 was six days.

Other Financing Activities

Bond Retirement

In April 2014, Pepco retired, at maturity, $175 million of its 4.65% senior notes. The senior notes were secured by a like principal amount of its 4.65% first mortgage bonds due April 15, 2014, which under the mortgage and deed of trust were deemed to be satisfied when the senior notes were repaid.

Sale of Receivables

On March 13, 2014, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a Task Order entered into under a General Services Administration area-wide agreement. The purchase price to be received by Pepco by the end of the time period is approximately $12 million. The energy savings project, which is being performed by Pepco Energy Services, is expected to be completed by January 1, 2015. Pursuant to the purchase agreement, following acceptance of the energy savings project, the buyer will be entitled to receive the contract payments under the Task Order payable by the customer over approximately 9 years. At June 30, 2014, $5 million of the purchase price had been received by Pepco.

(9) INCOME TAXES

A reconciliation of Pepco's effective income tax rates is as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	(millions of dollars)							
Income tax at federal statutory rate	$ 26	35.0%	$20	35.0%	$ 43	35.0%	$29	35.0%
Increases (decreases) resulting from:								
State income taxes, net of federal effect	4	5.4%	3	5.3%	7	5.7%	5	6.1%
Asset removal costs	(2)	(2.7)%	(3)	(5.3)%	(5)	(4.1)%	(6)	(7.3)%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	1	1.8%	(1)	(0.8)%	(4)	(4.9)%
Other, net	—	0.1%	(1)	(1.7)%	—	0.3%	(2)	(2.1)%
Income tax expense	$ 28	37.8%	$20	35.1%	$ 44	36.1%	$22	26.8%

In the first quarter of 2013, Pepco recorded changes in estimates and interest related to uncertain and effectively settled tax positions. On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which Pepco is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded an after-tax charge of $377 million in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in Pepco recording a $5 million interest benefit in the first quarter of 2013.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the Internal Revenue Service (IRS) issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. In February 2014, the IRS issued revenue procedures that describe how taxpayers should implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. Pepco does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its financial statements.

(10) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

Pepco applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Pepco utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, Pepco utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, Pepco's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Pepco's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value Measurements at June 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Cash equivalents and restricted cash equivalents				
Treasury funds	$ 27	$ 27	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	13	13	—	—
Life insurance contracts	61	—	42	19
	$101	$ 40	$ 42	$ 19
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 7	$ —	$ 7	$ —
	$ 7	$ —	$ 7	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2014.

	Fair Value Measurements at December 31, 2013			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Cash equivalents and restricted cash equivalents				
Treasury funds	$ 3	$ 3	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	13	13	—	—
Life insurance contracts	61	—	43	18
	$ 77	$ 16	$ 43	$ 18
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 7	$ —	$ 7	$ —
	$ 7	$ —	$ 7	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2013.

Pepco classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Executive deferred compensation plan assets and liabilities categorized as level 2 consist of life insurance policies and certain employment agreement obligations. The life insurance policies are categorized as level 2 assets because they are valued based on the assets underlying the policies, which consist of short-term cash equivalents and fixed income securities that are priced using observable market data and can be liquidated for the value of the underlying assets as of June 30, 2014. The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

The value of certain employment agreement obligations (which are included with life insurance contracts in the tables above) is derived using a discounted cash flow valuation technique. The discounted cash flow calculations are based on a known and certain stream of payments to be made over time that are discounted to determine their net present value. The primary variable input, the discount rate, is based on market-corroborated and observable published rates. These obligations have been classified as level 2 within the fair value hierarchy because the payment streams represent contractually known and certain amounts and the discount rate is based on published, observable data.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Executive deferred compensation plan assets include certain life insurance policies that are valued using the cash surrender value of the policies, net of loans against those policies. The cash surrender values do not represent a quoted price in an active market; therefore, those inputs are unobservable and the policies are categorized as level 3. Cash surrender values are provided by third parties and reviewed by Pepco for reasonableness.

Reconciliations of the beginning and ending balances of Pepco's fair value measurements using significant unobservable inputs (level 3) for the six months ended June 30, 2014 and 2013 are shown below:

	Life Insurance Contracts Six Months Ended June 30,	
	2014	**2013**
	(millions of dollars)	
Beginning balance as of January 1	$ 18	$ 18
Total gains (losses) (realized and unrealized):		
Included in income	2	3
Included in accumulated other comprehensive loss	—	—
Purchases	—	—
Issuances	(1)	(1)
Settlements	—	(1)
Transfers in (out) of level 3	—	—
Ending balance as of June 30	$ 19	$ 19

The breakdown of realized and unrealized gains on level 3 instruments included in income as a component of Other operation and maintenance expense for the periods below were as follows:

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars)	
Total gains included in income for the period	$ 2	$ 3
Change in unrealized gains relating to assets still held at reporting date	$ 2	$ 2

Other Financial Instruments

The estimated fair values of Pepco's Long-term debt instruments that are measured at amortized cost in Pepco's financial statements and the associated level of the estimates within the fair value hierarchy as of June 30, 2014 and December 31, 2013 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. Pepco's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and Pepco reviews the methodologies and results.

	Fair Value Measurements at June 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$2,530	$ —	$ 2,530	$ —
Long-term project funding	5	—	—	5
	$2,535	$ —	$ 2,530	$ 5

(a) The carrying amount for Long-term debt was $2,123 million as of June 30, 2014.

	Fair Value Measurements at December 31, 2013			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$2,127	$ —	$ 2,127	$ —
	$2,127	$ —	$ 2,127	$ —

(a) The carrying amount for Long-term debt was $1,899 million as of December 31, 2013.

The carrying amounts of all other financial instruments in the accompanying financial statements approximate fair value.

(11) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, Pepco is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. Pepco is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, Pepco's contracts with its vendors generally require the vendors to name Pepco as an additional insured for the amount at least equal to Pepco's self-insured retention. Further, Pepco's contracts with its vendors require the vendors to indemnify Pepco for various acts and activities that may give rise to claims against Pepco. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on Pepco's financial condition, results of operations or cash flows. At June 30, 2014, Pepco had recorded estimated loss contingency liabilities for general litigation totaling approximately $18 million (including amounts related to the matter specifically described below), and the portion of these estimated loss contingency liabilities in excess of the self-insured retention amount was substantially offset by estimated insurance receivables.

Substation Injury Claim

In May 2013, a contract worker erecting a scaffold at a Pepco substation came into contact with an energized station service feeder and suffered serious injuries. In August 2013, the individual filed suit against Pepco in the Circuit Court for Montgomery County, Maryland, seeking damages for medical expenses, loss of future earning capacity, pain and suffering and the cost of a life care plan aggregating to a maximum claim of approximately $28.1 million. Discovery is ongoing in the case and, if a settlement cannot be reached with respect to this matter, a trial is expected to begin in October 2014. Pepco has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident, including the policies of the contractor performing the scaffold work (which name Pepco as an additional insured), will offset substantially all of Pepco's costs associated with the resolution of this matter, including Pepco's self-insured retention amount. At June 30, 2014, Pepco has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of June 30, 2014. Pepco has also concluded as of June 30, 2014 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable of substantially the same amount as the related loss contingency liability.

Environmental Matters

Pepco is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of Pepco, environmental clean-up costs incurred by Pepco generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of Pepco described below at June 30, 2014 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
	(millions of dollars)		
Beginning balance as of January 1	$ 18	$ 3	$ 21
Accruals	—	—	—
Payments	1	—	1
Ending balance as of June 30	17	3	20
Less amounts in Other Current Liabilities	2	—	2
Amounts in Other Deferred Credits	$ 15	$ 3	$ 18

Peck Iron and Metal Site

The U.S Environmental Protection Agency (EPA) informed Pepco in a May 2009 letter that Pepco may be a potentially responsible party (PRP) under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that the Peck Iron and Metal scrap operations resulted in the improper storage and disposal of hazardous substances. EPA bases its allegation that Pepco arranged for disposal or treatment of hazardous substances sent to the site on information provided by former Peck Iron and Metal personnel, who informed EPA that Pepco was a customer at the site. Pepco has advised EPA by letter that its records show no evidence of any sale of scrap metal by Pepco to the site. Even if EPA has such records and such sales did occur, Pepco believes that any such scrap metal sales may be entitled to the recyclable material exemption from CERCLA liability. In a Federal Register notice published in November 2009, EPA placed the Peck Iron and Metal site on the National Priorities List. The National Priorities List, among other things, serves as a guide to EPA in determining which sites warrant further investigation to assess the nature and extent of the human health and environmental risks associated with a site. In September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Ward Transformer Site

In April 2009, a group of PRPs with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including Pepco, based on its alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including Pepco) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the Federal district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The Federal district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. Pepco has concluded that a loss is reasonably possible with respect to this matter, but is unable to estimate an amount or range of reasonably possible losses to which it may be exposed. Pepco does not believe that it had extensive business transactions, if any, with the Ward Transformer site.

Benning Road Site

In September 2010, PHI received a letter from EPA identifying the Benning Road location, consisting of a generation facility formerly operated by Pepco Energy Services, and a transmission and distribution service center facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The generation facility was deactivated in June 2012 and the plant structures are currently in the process of being demolished, but the service center remains in operation. The principal contaminants of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. 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 with the District of Columbia Department of the Environment (DDOE), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DDOE's selection of a remedial action for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DDOE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

The final phase of field work consisting of the installation of monitoring wells and groundwater sampling and analysis began in May 2014. In addition, as part of the remaining RI field work and in conjunction with the power plant demolition activities, Pepco and Pepco Energy Services will be collecting soil samples adjacent to and beneath the concrete basins for the cooling towers previously dismantled and removed from the generating plant. On May 23, 2014, Pepco and DDOE filed a joint status report with the court in which the parties projected that the field work would be completed by the end of 2014. Once all of the field work has been completed, Pepco and Pepco Energy Services will prepare RI/FS reports for review and approval by DDOE after solicitation and consideration of public comment. The next status report to the court is due on May 25, 2015.

The remediation costs accrued for this matter are included in the table above in the columns entitled "Transmission and Distribution" and "Legacy Generation – Regulated."

Potomac River Mineral Oil Release

In January 2011, a coupling failure on a transformer cooler pipe resulted in a release of non-toxic mineral oil at Pepco's Potomac River substation in Alexandria, Virginia. An overflow of an underground secondary containment reservoir resulted in approximately 4,500 gallons of mineral oil flowing into the Potomac River.

Beginning in March 2011, DDOE issued a series of compliance directives requiring Pepco to prepare an incident report, provide certain records, and prepare and implement plans for sampling surface water and river sediments and assessing ecological risks and natural resources damages. Pepco completed field sampling during the fourth quarter of 2011 and submitted sampling results to DDOE during the second quarter of 2012.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened enforcement action, including civil penalties, for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. In March 2014, Pepco and DDOE entered into a consent decree to resolve DDOE's threatened enforcement action, the terms of which include a combination of a civil penalty and a Supplemental Environmental Project (SEP) with a total cost to Pepco of $875,000. The consent decree was approved and entered by the District of Columbia

Superior Court on April 4, 2014. In accordance with the consent decree, Pepco made a penalty payment to DDOE in the amount of $250,000 and made a donation in the amount of $25,000 to the Northeast Environmental Enforcement Training Fund, Inc., a non-profit organization that funds scholarships for environmental enforcement training. In addition, to implement the SEP, as required by the consent decree, Pepco entered into an agreement with Living Classrooms Foundation, Inc., a non-profit educational organization, to provide $600,000 to fund the design, installation and operation of a trash collection system at a storm water outfall that drains to the Anacostia River. Finally, the consent decree confirmed that no further actions are required by Pepco to investigate, assess or remediate impacts to the river from the mineral oil release. Discussions will proceed separately with DDOE and the federal resource trustees regarding the settlement of a natural resource damage (NRD) claim under federal law. Based on discussions to date, PHI and Pepco do not believe that the resolution of DDOE's enforcement action or the federal NRD claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the mineral oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility which involve pumping accumulated storm water to an above-ground holding tank for off-site disposal. In December 2011, Pepco completed the installation of a treatment system designed to allow automatic discharge of accumulated storm water from the secondary containment system. Pepco currently is seeking DDOE's and EPA's approval to commence operation of the new system on a pilot basis to demonstrate its effectiveness in meeting both secondary containment requirements and water quality standards related to the discharge of storm water from the facility. In the meantime, Pepco is continuing to use the aboveground holding tank to manage storm water from the secondary containment system. Pepco also is evaluating other technical and regulatory options for managing storm water from the secondary containment system as alternatives to the proposed treatment system discharge currently under discussion with EPA and DDOE.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Metal Bank Site

In the first quarter of 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted Pepco on behalf of itself and other federal and state trustees to request that Pepco execute a tolling agreement to facilitate settlement negotiations concerning natural resource damages allegedly caused by releases of hazardous substances, including polychlorinated biphenyls, at the Metal Bank Superfund Site located in Philadelphia, Pennsylvania. Pepco executed a tolling agreement, which has been extended to March 15, 2015, and will continue settlement discussions with the NOAA, the trustees and other PRPs.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Brandywine Fly Ash Disposal Site

In February 2013, Pepco received a letter from the Maryland Department of the Environment (MDE) requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by GenOn MD Ash Management, LLC (GenOn). In July 2013, while reserving its rights and related defenses under a 2000 asset purchase and sale agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

PHI and Pepco have determined that a loss associated with this matter for Pepco is probable and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately $3 million to $6 million. Pepco believes that the costs incurred in this matter will be recoverable from GenOn under the 2000 sale agreement.

The amount accrued for this matter is included in the table above in the column entitled “Transmission and Distribution.”

(12) RELATED PARTY TRANSACTIONS

PHI Service Company provides various administrative and professional services to PHI and its regulated and unregulated subsidiaries, including Pepco. The cost of these services is allocated in accordance with cost allocation methodologies set forth in the service agreement using a variety of factors, including the subsidiaries’ share of employees, operating expenses, assets and other cost methods. These intercompany transactions are eliminated by PHI in consolidation and no profit results from these transactions at PHI. PHI Service Company costs directly charged or allocated to Pepco for the three months ended June 30, 2014 and 2013 were approximately $55 million and $52 million, respectively. PHI Service Company costs directly charged or allocated to Pepco for each of the six months ended June 30, 2014 and 2013 were approximately $107 million.

Pepco Energy Services performs utility maintenance services and high voltage underground transmission cabling, including services that are treated as capital costs, for Pepco. Amounts charged to Pepco by Pepco Energy Services for the three months ended June 30, 2014 and 2013 were approximately $6 million and $4 million, respectively. Amounts charged to Pepco by Pepco Energy Services for the six months ended June 30, 2014 and 2013 were approximately $10 million and $12 million, respectively.

As of June 30, 2014 and December 31, 2013, Pepco had the following balances on its balance sheets due to related parties:

	June 30, 2014	December 31, 2013
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (23)	$ (25)
Pepco Energy Services (b)	(6)	(7)
Total	$ (29)	$ (32)

(a) Included in Accounts payable due to associated companies.
(b) Pepco bills customers on behalf of Pepco Energy Services where Pepco Energy Services has performed work for certain government agencies under a General Services Administration area-wide agreement. Amount also includes charges for utility work performed by Pepco Energy Services on behalf of Pepco.

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Operating Revenue				
Electric	$ 251	$ 237	$ 551	$ 522
Natural gas	28	29	125	114
Total Operating Revenue	279	266	676	636
Operating Expenses				
Purchased energy	121	121	282	280
Gas purchased	13	15	71	69
Other operation and maintenance	65	63	131	132
Depreciation and amortization	30	27	60	52
Other taxes	10	9	21	19
Total Operating Expenses	239	235	565	552
Operating Income	40	31	111	84
Other Income (Expenses)				
Interest expense	(12)	(12)	(23)	(25)
Other income	4	2	6	4
Total Other Expenses	(8)	(10)	(17)	(21)
Income Before Income Tax Expense	32	21	94	63
Income Tax Expense	13	9	38	25
Net Income	$ 19	$ 12	$ 56	$ 38

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 149	$ 2
Restricted cash equivalents	5	—
Accounts receivable, less allowance for uncollectible accounts of $15 million and $12 million, respectively	187	208
Inventories	53	51
Deferred income tax assets, net	61	59
Income taxes and related accrued interest receivable	32	32
Prepaid expenses and other	1	9
Total Current Assets	488	361
OTHER ASSETS		
Goodwill	8	8
Regulatory assets	321	311
Prepaid pension expense	224	228
Income taxes and related accrued interest receivable	4	4
Other	13	12
Total Other Assets	570	563
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	3,819	3,673
Accumulated depreciation	(1,031)	(1,016)
Net Property, Plant and Equipment	2,788	2,657
TOTAL ASSETS	$ 3,846	$ 3,581

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 105	$ 252
Current portion of long-term debt	200	100
Accounts payable	33	46
Accrued liabilities	65	71
Accounts payable due to associated companies	20	22
Taxes accrued	3	4
Interest accrued	7	6
Customer deposits	27	25
Other	48	35
Total Current Liabilities	508	561
DEFERRED CREDITS		
Regulatory liabilities	240	229
Deferred income tax liabilities, net	857	816
Investment tax credits	4	5
Other postretirement benefit obligations	21	23
Other	35	36
Total Deferred Credits	1,157	1,109
OTHER LONG-TERM LIABILITIES		
Long-term debt	971	867
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
EQUITY		
Common stock, $2.25 par value, 1,000 shares authorized, 1,000 shares outstanding	—	—
Premium on stock and other capital contributions	537	407
Retained earnings	673	637
Total Equity	1,210	1,044
TOTAL LIABILITIES AND EQUITY	$ 3,846	$ 3,581

The accompanying Notes are an integral part of these Financial Statements.

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 56	$ 38
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	60	52
Deferred income taxes	38	27
Changes in:		
Accounts receivable	21	19
Inventories	(2)	(3)
Regulatory assets and liabilities, net	(17)	(13)
Accounts payable and accrued liabilities	(6)	(23)
Pension contributions	—	(10)
Income tax-related prepayments, receivables and payables	(1)	(2)
Interest accrued	1	3
Other assets and liabilities	5	15
Net Cash From Operating Activities	155	103
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(172)	(164)
Changes in restricted cash equivalents	(5)	—
Net other investing activities	3	1
Net Cash Used By Investing Activities	(174)	(163)
FINANCING ACTIVITIES		
Dividends paid to Parent	(20)	(20)
Capital contributions from Parent	130	—
Issuances of long term debt	204	—
(Repayments) issuances of short-term debt, net	(147)	77
Cost of issuances	(1)	—
Net Cash From Financing Activities	166	57
Net Increase (Decrease) in Cash and Cash Equivalents	147	(3)
Cash and Cash Equivalents at Beginning of Period	2	6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 149	$ 3
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes, (includes payments from PHI for federal income taxes)	$ —	$ (1)

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
BALANCE, DECEMBER 31, 2013	1,000	$ —	$ 407	$ 637	$1,044
Net Income	—	—	—	37	37
Dividends on common stock	—	—	—	(20)	(20)
BALANCE, MARCH 31, 2014	1,000	—	407	654	1,061
Net Income	—	—	—	19	19
Capital contribution from Parent	—	—	130	—	130
BALANCE, JUNE 30, 2014	1,000	$ —	$ 537	$ 673	$1,210

The accompanying Notes are an integral part of these Financial Statements.

NOTES TO FINANCIAL STATEMENTS

DELMARVA POWER & LIGHT COMPANY

(1) ORGANIZATION

Delmarva Power & Light Company (DPL) is engaged in the transmission and distribution of electricity in Delaware and portions of Maryland and provides natural gas distribution service in northern Delaware. Additionally, DPL provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territories who do not elect to purchase electricity from a competitive supplier. Default Electricity Supply is known as Standard Offer Service in both Delaware and Maryland. DPL is a wholly owned subsidiary of Conectiv, LLC, which is wholly owned by Pepco Holdings, Inc. (Pepco Holdings or PHI).

PHI has entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly-owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly-owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly-owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly-owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on July 29, 2014, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission, the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission, the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976; and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger

Agreement and the closing of the Merger or the termination of the Merger Agreement) . In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). The parties currently anticipate that the closing will occur in the second or third quarter of 2015.

The Merger Agreement may be terminated by each of PHI and Exelon under certain circumstances, including if the Merger is not consummated by July 29, 2015 (subject to extension to October 29, 2015, if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for both PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals (a Regulatory Termination), Exelon will pay PHI a reverse termination fee equal to the purchase price paid up to the date of termination by Exelon to purchase the Preferred Stock, through PHI’s redemption of the Preferred Stock for nominal consideration. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

DPL’s unaudited financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been omitted. Therefore, these financial statements should be read along with the annual financial statements included in DPL’s annual report on Form 10-K for the year ended December 31, 2013. In the opinion of DPL’s management, the unaudited financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly DPL’s financial condition as of June 30, 2014, in accordance with GAAP. The year-end December 31, 2013 balance sheet included herein was derived from audited financial statements, but does not include all disclosures required by GAAP. Interim results for the three and six months ended June 30, 2014 may not be indicative of DPL’s results that will be realized for the full year ending December 31, 2014.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the financial statements and accompanying notes. Although DPL believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset and goodwill impairment evaluations, fair value calculations for derivative instruments, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of loss contingency liabilities for general litigation and auto and other liability claims, and income tax provisions and reserves. Additionally, DPL is subject to legal, regulatory, and other proceedings and claims that arise in the ordinary course of its business. DPL records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Consolidation of Variable Interest Entities

DPL assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests. See Note (15), “Variable Interest Entities,” for additional information.

Goodwill

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired at the acquisition date. DPL tests its goodwill for impairment annually as of November 1 and whenever an event occurs or circumstances change in the interim that would more likely than not (that is, a greater than 50% chance) reduce the estimated fair value of DPL below the carrying amount of its net assets. Factors that may result in an interim impairment test include, but are not limited to: a change in the identified reporting unit, an adverse change in business conditions, an adverse regulatory action, or an impairment of DPL’s long-lived assets. DPL performed its most recent annual impairment test as of November 1, 2013, and its goodwill was not impaired as described in Note (6), “Goodwill.”

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in DPL’s gross revenues were $4 million for each of the three months ended June 30, 2014 and 2013, and $8 million for each of the six months ended June 30, 2014 and 2013.

Reclassifications

Certain prior period amounts have been reclassified in order to conform to the current period presentation.

Revision of Prior Period Financial Statements

Operating and Financing Cash Flows

The statement of cash flows for the six months ended June 30, 2013 has been revised to correctly present changes in book overdraft balances as operating activities (included in Changes in accounts payable and accrued liabilities) rather than financing activities (included previously in Net other financing activities). For the six months ended June 30, 2013, the effect of the revision was to decrease Net cash from operating activities by $2 million from $105 million to $103 million, and increase Net cash from financing activities by $2 million from $55 million to $57 million. The revision was not considered to be material, individually or in the aggregate, to previously issued financial statements.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Liabilities (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, DPL is required to measure such obligations as the sum of the amount it agreed to pay on the basis of its arrangement among co-obligors and any additional amount it expects to pay on behalf of its co-obligors. Adoption of this guidance during the first quarter of 2014 did not have a material impact on DPL’s financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance requiring netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The prospective adoption of this guidance at March 31, 2014 resulted in DPL netting liabilities related to uncertain tax positions with deferred tax assets for net operating loss and other carryforwards (included in deferred income tax liabilities, net) and income taxes receivable (including income tax deposits) related to effectively settled uncertain tax positions.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements are effective for DPL beginning January 1, 2017, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2017. Early adoption is not permitted. DPL is currently evaluating the potential impact of this new guidance on its financial statements and which implementation approach to select.

(5) SEGMENT INFORMATION

DPL operates its business as one regulated utility segment, which includes all of its services as described above.

(6) GOODWILL

DPL's goodwill balance of $8 million was unchanged during the six months ended June 30, 2014. All of DPL's goodwill was generated by its acquisition of Conowingo Power Company in 1995.

DPL's annual impairment test as of November 1, 2013 indicated that goodwill was not impaired. For the six months ended June 30, 2014, DPL concluded that there were no events or circumstances requiring it to perform an interim goodwill impairment test. DPL will perform its next annual impairment test as of November 1, 2014.

(7) REGULATORY MATTERS

Rate Proceedings

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings as indicated below.

Bill Stabilization Adjustment

DPL has proposed in each of its respective jurisdictions the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. To date:

- A bill stabilization adjustment (BSA) has been approved and implemented for DPL electric service in Maryland.
- A proposed modified fixed variable rate design (MFVRD) for DPL electric and natural gas service in Delaware was filed in 2009 for consideration by the DPSC and while there was little activity associated with this filing in 2013, or to date in 2014, the proceeding remains open.

Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission. The MFVRD proposed in Delaware contemplates a fixed customer charge (i.e., not tied to the customer's volumetric consumption of electricity or natural gas) to recover the utility's fixed costs, plus a reasonable rate of return.

Delaware

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The application sought approval of an annual rate increase of approximately $42 million (adjusted by DPL to approximately $39 million on September 20, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on June 1, 2013, subject to refund and pending final DPSC approval. On October 8, 2013, the DPSC approved DPL's request to implement an additional interim increase of $25.1 million, effective on October 22, 2013, bringing the total interim rates in effect subject to refund to $27.6 million. At the conclusion of a meeting held on April 1 and 2, 2014, the DPSC issued an order providing for an annual increase in DPL's electric distribution base rates of approximately $15.1 million, based on an ROE of 9.70%. The amounts contained in the DPSC order are subject to verification by all parties to the base rate proceeding and may be changed by further order of the DPSC upon such verification. A final order in this proceeding is expected to be issued by the DPSC in the third quarter of 2014. The new rates became effective May 1, 2014. DPL will submit a rate refund plan to provide credit or refund to any customer whose rates were increased in October 2013 in an amount that exceeded the increase approved by the DPSC. It is anticipated that refunds will be issued beginning September 2, 2014. The final order in this proceeding is not expected to be affected by the Merger Agreement. Under the Merger Agreement, DPL is not permitted to file further electric distribution base rate cases in Delaware without Exelon's consent.

Forward Looking Rate Plan

On October 2, 2013, DPL filed a multi-year rate plan, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would provide for annual electric distribution base rate increases over a four-year period in the aggregate amount of approximately $56 million. The FLRP as proposed provides the opportunity to achieve estimated earned ROEs of 7.41% and 8.80% in years one and two, respectively, and 9.75% in both years three and four of the plan.

In addition, DPL proposed that as part of the FLRP, in order to provide a higher minimum required standard of reliability for DPL's customers than that to which DPL is currently subject, the standards by which DPL's reliability is measured would be made more stringent in each year of the FLRP. DPL has also offered to refund an aggregate of $500,000 to customers in each year of the FLRP that it fails to meet the proposed stricter minimum reliability standards.

On October 22, 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that it would not address the FLRP until the electric distribution base rate case discussed above was concluded. A schedule for the FLRP docket has not yet been established. Under the Merger Agreement, DPL is permitted to pursue this matter.

Gas Distribution Base Rates

A settlement approved in October 2013 by the DPSC in a proceeding filed by DPL in December 2012 to increase its natural gas distribution base rates provides in part for a phase-in of the recovery of the deferred costs associated with DPL's deployment of the interface management unit (IMU). The IMU is part of DPL's advanced metering infrastructure (AMI) and allows for the remote reading of gas meters. Recovery of such costs will occur through base rates over a two-year period, assuming specific milestones are met and pursuant to the following schedule: 50% of the IMU portion of DPL's AMI was put into rates on July 11, 2014, and the remainder will be put into rates on April 1, 2015. DPL also agreed in the settlement that its next natural gas distribution base rate application may be filed with the DPSC no earlier than January 1, 2015. Under the Merger Agreement, DPL is not permitted to file further gas distribution base rate cases without Exelon's consent.

Gas Cost Rates

DPL makes an annual Gas Cost Rate (GCR) filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. On August 28, 2013, DPL made its 2013 GCR filing. The rates proposed in the 2013 GCR filing would result in a GCR decrease of approximately 5.5%. On September 26, 2013, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2013, subject to refund and pending final DPSC approval. On July 8, 2014, the DPSC issued an order approving the GCR rates as filed by DPL. Under the Merger Agreement, DPL is permitted to continue to file its required annual GCR cases in Delaware.

<u>Federal Energy Regulatory Commission</u>

In October 2013, FERC issued a ruling on challenges filed by the Delaware Municipal Electric Corporation, Inc. (DEMEC) to DPL's 2011 and 2012 annual formula rate updates. In 2006, FERC approved a formula rate for DPL that is incorporated into the PJM Interconnection, LLC (PJM) tariff. The formula rate establishes the treatment of costs and revenues and the resulting rates for DPL. Pursuant to the protocols approved by FERC and after a period of discovery, interested parties have an opportunity to file challenges regarding the application of the formula rate. The October 2013 FERC order sets various issues in this proceeding for hearing, including challenges regarding formula rate inputs, deferred income items, prepayments of estimated income taxes, rate base reductions, various administrative and general expenses and the inclusion in rate base of construction work in progress related to the Mid-Atlantic Power Pathway (MAPP) project abandoned by PJM. Settlement discussions began in this matter on November 5, 2013 before an administrative law judge at FERC.

In December 2013, DEMEC filed a formal challenge to the DPL 2013 annual formula rate update, including a request to consolidate the 2013 challenge with the two prior challenges. On April 8, 2014, FERC issued an order setting the 2013 challenge issues for hearing and on April 15, 2014, those issues were consolidated with the 2011 and 2012 challenges. Settlement procedures will continue with the three challenges in one proceeding. PHI cannot predict when a final FERC decision in this proceeding will be issued.

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as DEMEC, filed a joint complaint with FERC against DPL and its affiliates Potomac Electric Power Company (Pepco) and Atlantic City Electric Company (ACE), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for DPL and its utility affiliates is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. DPL believes the allegations in this complaint are without merit and is vigorously contesting it. In April 2013, DPL filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that the complaint failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. DPL cannot predict when a final FERC decision in this proceeding will be issued.

Under the Merger Agreement, DPL is permitted, and intends to continue, to pursue the conclusion of these matters.

On June 19, 2014, FERC issued an order in a proceeding in which DPL was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint filed against DPL and its utility affiliates, DPL believes that it is probable that FERC will direct DPL to use this methodology at the time it issues an order addressing the complaint. As a result, DPL applied an estimated ROE based on the two-step methodology announced by FERC for the period over which DPL's transmission revenues would be subject to refund as a result of the challenge, and has recorded an estimated reserve in the second quarter of 2014 related to this matter.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland. In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 megawatts (MWs) beginning in 2015. The order requires DPL, its affiliate Pepco and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative standard offer service (SOS) loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs' concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that each of the Contract EDCs will recover its costs associated with the contract through surcharges on its respective SOS customers.

In April 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC's order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. The Maryland circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, DPL entered into a contract in accordance with the terms of the MPSC's order; however, under the contract's terms, it will not become effective, if at all, until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit. On June 2, 2014, the Fourth Circuit issued a decision affirming the lower Federal court judgment. On June 16, 2014, both the winning bidder and the MPSC sought rehearing of the Fourth Circuit's decision. On June 30, 2014, the Fourth Circuit denied the rehearing requests of the winning bidder and the MPSC. On July 8, 2014, the Fourth Circuit issued its mandate stating that its decision takes effect on that date, which means that the parties have until September 29, 2014 to appeal the Fourth Circuit's decision to the U.S. Supreme Court. The appeal to the Maryland Court of Special Appeals remains pending.

On June 2, 2014, the winning bidder filed the contracts with FERC requesting that they be accepted pursuant to Section 205 of the Federal Power Act. The Contract EDCs intervened in the proceeding and requested that the winning bidder's filing be rejected on the grounds that the contracts never came into effect.

Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, DPL continues to believe that it may be required to record its proportional share of the contracts as a derivative instrument at fair value and record a related regulatory asset of approximately the same amount because DPL would recover any payments under the contracts from SOS customers. DPL has concluded that any accounting for these contracts would not be required until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

DPL continues to evaluate these proceedings to determine, should the contracts be found to be valid and enforceable, (i) the extent of the negative effect that the contracts may have on DPL's credit metrics, as calculated by independent rating agencies that evaluate and rate DPL and its debt issuances, (ii) the effect on DPL's ability to recover its associated costs of the contracts if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contracts on the financial condition, results of operations and cash flows of DPL.

MAPP Settlement Agreement

In February 2014, FERC issued an order approving the settlement agreement submitted by DPL in connection with DPL's proceeding seeking recovery of approximately $38 million in abandonment costs related to the MAPP project. DPL had been directed by PJM to construct the MAPP project, a 152-mile high-voltage interstate transmission line, and was subsequently directed by PJM to cancel it. The abandonment costs sought for recovery were subsequently reduced to $37 million from write-offs of certain disallowed costs in 2013. Under the terms of the FERC-approved settlement agreement, DPL will receive $36.6 million of transmission revenues over a three-year period, which began on June 1, 2013, and will retain title to all real property and property rights acquired in connection with the MAPP project, which had an estimated fair value of $6 million. The FERC-approved settlement agreement resolves all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project, and the terms of the settlement agreement are not subject to modification through any other FERC proceeding. As of June 30, 2014, DPL had a regulatory asset related to the MAPP abandonment costs of approximately $19 million, net of amortization, and land of $6 million. DPL expects to recognize pre-tax income related to the MAPP abandonment costs of $3 million in 2014 and $1 million in 2015.

Merger Approval Proceedings

Delaware

On June 18, 2014, Exelon, PHI and DPL, and certain of their respective affiliates, filed an application with the DPSC seeking approval of the Merger. Delaware law requires the DPSC to approve the Merger when it determines that the transaction is in accordance with law, for a proper purpose, and is consistent with the public interest. The DPSC must further find that the successor will continue to provide safe and reliable service, will not terminate or impair existing collective bargaining agreements and will engage in good faith bargaining with organized labor. By statute, the review of this application must be concluded within 120 days, unless additional time is agreed to by the applicants and the DPSC. On July 8, 2014, the DPSC issued an order approving the schedule agreed to by the parties, which provides for a final DPSC order in this proceeding to be issued on or before January 6, 2015.

Maryland

Approval of the Merger by the MPSC is required, but the application for approval of the Merger has not yet been filed. Maryland law requires the MPSC to approve a merger subject to its review if it finds that the merger is consistent with the public interest, convenience and necessity, including its benefits to and impact on consumers. In making this determination, the MPSC is required to consider the following 12 criteria: (i) the potential impact of the merger on rates and charges paid by customers and on the services and conditions of operation of the utility; (ii) the potential impact of the merger on continuing investment needs for the maintenance of utility services, plant and related infrastructure; (iii) the proposed capital structure that will result from the merger, including allocation of earnings from the utility; (iv) the potential effects on employment by the utility; (v) the projected allocation between the utility's shareholders and ratepayers of any savings that are expected; (vi) issues of reliability, quality of service and quality of customer service; (vii) the potential impact of the merger on community investment; (viii) affiliate and cross-subsidization issues; (ix) the use or pledge of utility assets for the benefit of an affiliate; (x) jurisdictional and choice-of-law issues; (xi) whether it is necessary to revise the MPSC's ring-fencing and affiliate code of conduct regulations in light of the merger; and (xii) any other issues the MPSC considers relevant to the assessment of the merger. Once the application is filed, the MPSC is required to issue an order within 180 days. However, the MPSC can grant a 45-day extension for good cause. If no order is issued by the statutory deadline, then the Merger would be deemed to be approved. DPL anticipates filing the merger approval application with the MPSC in the third quarter of 2014.

Virginia

On June 3, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, filed an application with the VSCC seeking approval of the Merger. Virginia law provides that, if the VSCC determines, with or without hearing, that adequate service to the public at just and reasonable rates will not be impaired or jeopardized by granting the application for approval, then the VSCC shall approve a merger with such conditions that the VSCC deems to be appropriate in order to satisfy this standard. The VSCC is required to rule on the application within 60 days, which may be extended by up to 120 days. On June 16, 2014, the VSCC issued an order extending the time period for issuing a decision by an additional 60 days, to October 1, 2014.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the Federal Power Act. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. The companies requested that FERC find that the transaction is consistent with the public interest and grant approval within 90 days.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

DPL accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and its other postretirement benefits plan (the Pepco Holdings, Inc. Welfare Plan for Retirees), as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended June 30, 2014 and 2013, before intercompany allocations from the PHI Service Company, were $10 million and $29 million, respectively. DPL's allocated share was $1 million and $6 million for the three months ended June 30, 2014 and 2013, respectively. PHI's pension and other postretirement net periodic benefit cost for the six months ended June 30, 2014 and 2013, before intercompany allocations from the PHI Service Company, were $28 million and $54 million, respectively. DPL's allocated share was $4 million and $10 million for the six months ended June 30, 2014 and 2013, respectively.

In the first quarter of 2013, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan of $10 million. In 2014, DPL has made no such contributions.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and became effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $13 million reduction in DPL's net periodic benefit cost for other postretirement benefits during the six months ended June 30, 2014 when compared to the six months ended June 30, 2013. DPL anticipates approximately 37% of annual net periodic other postretirement benefit costs will be capitalized.

(9) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility is currently August 1, 2018.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion, and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 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 sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of June 30, 2014.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of June 30, 2014 and December 31, 2013, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $736 million and $332 million, respectively. DPL's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by Pepco and ACE and the portion of the total capacity being used by PHI.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings.

Commercial Paper

DPL maintains an on-going commercial paper program to address its short-term liquidity needs. As of June 30, 2014, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had no commercial paper outstanding at June 30, 2014. The weighted average interest rate for commercial paper issued by DPL during the six months ended June 30, 2014 was 0.26% and the weighted average maturity of all commercial paper issued by DPL during the six months ended June 30, 2014 was five days.

Other Financing Activities

Bond Issuance

In June 2014, DPL issued $200 million of its 3.50% first mortgage bonds due November 15, 2023. Net proceeds from the issuance of the bonds, which included a premium of $4 million, were used to repay DPL's outstanding commercial paper and for general corporate purposes.

(10) INCOME TAXES

A reconciliation of DPL's effective income tax rates is as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	(millions of dollars)							
Income tax at federal statutory rate	$ 11	35.0%	$ 7	35.0%	$ 33	35.0%	$ 22	35.0%
Increases (decreases) resulting from:								
State income taxes, net of federal effect	2	6.3%	1	4.8%	5	5.3%	3	4.8%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	—	—	—	—	(1)	(1.6)%
Depreciation	—	—	—	—	(1)	(1.1)%	—	—
Other, net	—	(0.7)%	1	3.1%	1	1.2%	1	1.5%
Income tax expense	$ 13	40.6%	$ 9	42.9%	$ 38	40.4%	$ 25	39.7%

In the first quarter of 2013, DPL recorded changes in estimates and interest related to uncertain and effectively settled tax positions. On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which DPL is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded an after-tax charge of $377 million in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in DPL recording a $1 million interest benefit in the first quarter of 2013.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the Internal Revenue Service (IRS) issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. In February 2014, the IRS issued revenue procedures that describe how taxpayers should implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. DPL does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its financial statements.

(11) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

DPL uses derivative instruments in the form of swaps and over-the-counter options primarily to reduce natural gas commodity price volatility and limit its customers' exposure to increases in the market price of natural gas under a hedging program approved by the DPSC. DPL uses these derivatives to manage the commodity price risk associated with its physical natural gas purchase contracts. The natural gas purchase contracts qualify as normal purchases, which are not required to be recorded in the financial statements until settled. All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all gains and losses related to hedging activities, are deferred under FASB guidance on regulated operations (ASC 980) until recovered from its customers through a fuel adjustment clause approved by the DPSC.

As of June 30, 2014, DPL had gross and net derivative instruments of less than $1 million.

The table below identifies the balance sheet location and fair values of derivative instruments as of December 31, 2013:

	As of December 31, 2013				
Balance Sheet Caption	**Derivatives Designated as Hedging Instruments**	**Other Derivative Instruments**	**Gross Derivative Instruments**	**Effects of Cash Collateral and Netting**	**Net Derivative Instruments**
			(millions of dollars)		
Derivative assets (current assets)	$ —	$ 1	$ 1	$ (1)	$ —
Total Derivative asset	$ —	$ 1	$ 1	$ (1)	$ —

All derivative assets and liabilities available to be offset under master netting arrangements were netted as of June 30, 2014 and December 31, 2013. The amount of cash collateral that was offset against these derivative positions is as follows:

	June 30, 2014	**December 31, 2013**
	(millions of dollars)	
Cash collateral received from counterparties with the obligation to return	$ —	$ (1)

As of June 30, 2014 and December 31, 2013, all DPL cash collateral pledged related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Other Derivative Activity

DPL has certain derivatives that are not in hedge accounting relationships and are not designated as normal purchases or normal sales. These derivatives are recorded at fair value on the balance sheets with the gain or loss for changes in the fair value recorded in income. In addition, in accordance with FASB guidance on regulated operations, regulatory liabilities or regulatory assets of the same amount are recorded on the balance sheets and the recognition of the derivative gain or loss is deferred because of the DPSC-approved fuel adjustment clause. For the three months ended June 30, 2014 and 2013, the net unrealized derivative gains arising during the period that were deferred as Regulatory liabilities and the net realized losses and gains recognized in the statements of income (through Purchased energy and Gas purchased expense) that were also deferred as Regulatory liabilities are provided in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Net unrealized (losses) gains arising during the period	$ —	$ (2)	$ 2	$ —
Net realized gains (losses) recognized during the period	1	1	3	(3)

As of June 30, 2014 and December 31, 2013, DPL had the following net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting:

	June 30, 2014		December 31, 2013	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
Natural gas (One Million British Thermal Units (MMBtu))	3,265,000	Long	3,977,500	Long

Contingent Credit Risk Features

The primary contracts used by DPL for derivative transactions are entered into under the International Swaps and Derivatives Association Master Agreement (ISDA) or similar agreements that closely mirror the principal credit provisions of the ISDA. The ISDAs include a Credit Support Annex (CSA) that governs the mutual posting and administration of collateral security. The failure of a party to comply with an obligation under the CSA, including an obligation to transfer collateral security when due or the failure to maintain any required credit support, constitutes an event of default under the ISDA for which the other party may declare an early termination and liquidation of all transactions entered into under the ISDA, including foreclosure against any collateral security. In addition, some of the ISDAs have cross default provisions under which a default by a party under another commodity or derivative contract, or the breach by a party of another borrowing obligation in excess of a specified threshold, is a breach under the ISDA.

Under the ISDA or similar agreements, the parties establish a dollar threshold of unsecured credit for each party in excess of which the party would be required to post collateral to secure its obligations to the other party. The amount of the unsecured credit threshold varies according to the senior, unsecured debt rating of the respective parties or that of a guarantor of the party’s obligations. The fair values of all transactions between the parties are netted under the master netting provisions. Transactions may include derivatives accounted for on-balance sheet as well as normal purchases and normal sales that are accounted for off-balance sheet. If the aggregate fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The obligations of DPL are stand-alone obligations without the guaranty of PHI. If DPL’s debt rating were to fall below “investment grade,” the unsecured credit threshold would typically be set at zero and collateral would be required for the entire net loss position. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder.

The gross fair values of DPL's derivative liabilities with credit-risk-related contingent features as of June 30, 2014 and December 31, 2013 were zero.

DPL's primary source for posting cash collateral or letters of credit is PHI's credit facility under which DPL is a borrower. As of June 30, 2014 and December 31, 2013, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries was $736 million and $332 million, respectively.

(12) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

DPL applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). DPL utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, DPL utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, DPL's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. DPL's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Description	Fair Value Measurements at June 30, 2014			
	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
ASSETS				
Cash equivalents and restricted cash equivalents				
Treasury funds	$150	$ 150	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	1	1	—	—
Life insurance contracts	1	—	—	1
	$152	$ 151	$ —	$ 1
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 1	$ —	$ 1	$ —
	$ 1	$ —	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2014.

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2013			
	(millions of dollars)			
ASSETS				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	1	1	—	—
Life insurance contracts	1	—	—	1
	$ 3	$ 2	$ —	$ 1
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 1	$ —	$ 1	$ —
	$ 1	$ —	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2013.
(b) The fair value of derivative assets reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas swaps purchased by DPL as part of a natural gas hedging program approved by the DPSC.

DPL classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis, such as the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 2 executive deferred compensation plan liabilities associated with the life insurance policies represent a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Executive deferred compensation plan assets include certain life insurance policies that are valued using the cash surrender value of the policies, net of loans against those policies. The cash surrender values do not represent a quoted price in an active market; therefore, those inputs are unobservable and the policies are categorized as level 3. Cash surrender values are provided by third parties and reviewed by DPL for reasonableness.

Reconciliations of the beginning and ending balances of DPL's fair value measurements using significant unobservable inputs (level 3) for the six months ended June 30, 2014 and 2013 are shown below:

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	
	Life Insurance Contracts	Natural Gas	Life Insurance Contracts
	(millions of dollars)		
Balance as of January 1	$ 1	$ (4)	$ 1
Total gains (losses) (realized and unrealized):			
Included in income	—	—	—
Included in accumulated other comprehensive loss	—	—	—
Included in regulatory liabilities	—	—	—
Purchases	—	—	—
Issuances	—	—	—
Settlements	—	4	—
Transfers in (out) of Level 3	—	—	—
Balance as of June 30	$ 1	$ —	$ 1

Other Financial Instruments

The estimated fair values of DPL's Long-term debt instruments that are measured at amortized cost in DPL's financial statements and the associated level of the estimates within the fair value hierarchy as of June 30, 2014 and December 31, 2013 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. DPL's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and DPL reviews the methodologies and results.

The fair value of Long-term debt categorized as level 3 is based on a discounted cash flow methodology using observable inputs, such as the U.S. Treasury yield, and unobservable inputs, such as credit spreads, because quoted prices for the debt or similar debt in active markets were insufficient.

	Fair Value Measurements at June 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,204	$ —	$ 1,095	$ 109
	$1,204	$ —	$ 1,095	$ 109

(a) The carrying amount for Long-term debt was $1,171 million as of June 30, 2014.

Description	Total	Fair Value Measurements at December 31, 2013 Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$960	$ —	$ 850	$ 110
	$960	$ —	$ 850	$ 110

(a) The carrying amount for Long-term debt was $967 million as of December 31, 2013.

The carrying amounts of all other financial instruments in the accompanying consolidated financial statements approximate fair value.

(13) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, DPL is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. DPL is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, DPL's contracts with its vendors generally require the vendors to name DPL as an additional insured for the amount at least equal to DPL's self-insured retention. Further, DPL's contracts with its vendors require the vendors to indemnify DPL for various acts and activities that may give rise to claims against DPL. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on DPL's financial condition, results of operations or cash flows. At June 30, 2014, DPL had recorded estimated loss contingency liabilities for general litigation totaling approximately $2 million.

Environmental Matters

DPL is subject to regulation by various federal, regional, state, and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from DPL's customers, environmental clean-up costs incurred by DPL generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of DPL described below at June 30, 2014 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
	(millions of dollars)		
Beginning balance as of January 1	$ 1	$ 2	$ 3
Accruals	—	—	—
Payments	—	—	—
Ending balance as of June 30	1	2	3
Less amounts in Other Current Liabilities	1	1	2
Amounts in Other Deferred Credits	$ —	$ 1	$ 1

Ward Transformer Site

In April 2009, a group of potentially responsible parties (PRPs) with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including DPL, based on its alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including DPL) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the Federal district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The Federal district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. DPL has concluded that a loss is reasonably possible with respect to this matter, but is unable to estimate an amount or range of reasonably possible losses to which it may be exposed. DPL does not believe that it had extensive business transactions, if any, with the Ward Transformer site.

Indian River Oil Release

In 2001, DPL entered into a consent agreement with the Delaware Department of Natural Resources and Environmental Control for remediation, site restoration, natural resource damage compensatory projects and other costs associated with environmental contamination resulting from an oil release at the Indian River generating facility, which was sold in June 2001. The amount of remediation costs accrued for this matter is included in the table above in the column entitled "Legacy Generation – Regulated."

Metal Bank Site

In the first quarter of 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted DPL on behalf of itself and other federal and state trustees to request that DPL execute a tolling agreement to facilitate settlement negotiations concerning natural resource damages allegedly caused by releases of hazardous substances, including polychlorinated biphenyls, at the Metal Bank Superfund Site located in Philadelphia, Pennsylvania. DPL executed a tolling agreement, which has been extended to March 15, 2015, and will continue settlement discussions with the NOAA, the trustees and other PRPs.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

(14) RELATED PARTY TRANSACTIONS

PHI Service Company provides various administrative and professional services to PHI and its regulated and unregulated subsidiaries, including DPL. The cost of these services is allocated in accordance with cost allocation methodologies set forth in the service agreement using a variety of factors, including the subsidiaries' share of employees, operating expenses, assets and other cost methods. These intercompany transactions are eliminated by PHI in consolidation and no profit results from these transactions at PHI. PHI Service Company costs directly charged or allocated to DPL for the three months ended June 30, 2014 and 2013 were approximately $40 million and $38 million, respectively. PHI Service Company costs directly charged or allocated to DPL for the six months ended June 30, 2014 and 2013 were approximately $79 million and $78 million, respectively.

In addition to the PHI Service Company charges described above, DPL's financial statements include the following related party transactions in its statements of income:

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars)			
Intercompany lease transactions (a)	$ 1	$ 1	$ 2	$ 2

(a) Included in Electric revenue.

As of June 30, 2014 and December 31, 2013, DPL had the following balances on its balance sheets due to related parties:

	June 30, 2014	December 31, 2013
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (19)	$ (22)
Other	(1)	—
Total	$ (20)	$ (22)

(a) Included in Accounts payable due to associated companies.

(15) VARIABLE INTEREST ENTITIES

DPL is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if DPL is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. DPL performed a qualitative analysis to determine whether a variable interest provided a controlling financial interest in any of it VIEs at June 30, 2014, as described below.

DPL is subject to Renewable Energy Portfolio Standards (RPS) in the state of Delaware that require it to obtain renewable energy credits (RECs) for energy delivered to its customers. DPL's costs associated with obtaining RECs to fulfill its RPS obligations are recoverable from its customers by law. As of June 30, 2014, DPL is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 MWs, one solar PPA with a 10 MW facility and an agreement with the Delaware Sustainable Energy Utility (DSEU) to purchase solar renewable energy credits (SREC). Each of the facilities associated with these PPAs is operational, and DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and SRECs from the solar facility and DSEU, up to certain amounts (as set forth below) at rates that are primarily fixed under the respective agreements. DPL has concluded that while VIEs exist under these contracts, consolidation is not required under the FASB guidance on the consolidation of variable interest entities as DPL is not the primary beneficiary. DPL has not provided financial or other support under these arrangements that it was not previously contractually required to provide during the periods presented, nor does DPL have any intention to provide such additional support.

Because DPL has no equity or debt interest in these renewable energy transactions, the maximum exposure to loss relates primarily to any above-market costs incurred for power, RECs or SRECs. Due to unpredictability in the amount of MW's ultimately purchased under the agreements for purchased renewable energy, RECs and SRECs, PHI and DPL are unable to quantify the maximum exposure to loss. The power purchases, REC and SREC costs are recoverable from DPL's customers through regulated rates.

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from the second wind facility through 2031 in amounts not to exceed 40 MWs, and from the third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's aggregate purchases under the three wind PPAs totaled $7 million for each of the three months ended June 30, 2014 and 2013. DPL's aggregate purchases under the three wind PPAs totaled $17 million for each of the six months ended June 30, 2014 and 2013.

The term of the agreement with the solar facility is through 2030 and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. The DSEU may enter into 20-year contracts with solar facilities to purchase SRECs for resale to DPL. Under the agreement, DPL is obligated to purchase SRECs in amounts not to exceed 19 MWs at annually determined auction rates. DPL's purchases under these solar agreements were $1 million and less than $1 million for the three months ended June 30, 2014 and 2013, respectively. DPL's purchases under these solar agreements were $2 million and less than $1 million for the six months ended June 30, 2014 and 2013, respectively.

On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to fuel cell facilities totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL would be an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour of energy produced by the fuel cell facilities through 2033. DPL has no obligation to the qualified fuel cell provider other than to remit payments collected from its distribution customers pursuant to the tariff. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. At June 30, 2014 and 2013, 30 MWs and 15 MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $9 million and $3 million to distribution customers for the three months ended June 30, 2014 and 2013, respectively. DPL billed $18 million and $6 million to distribution customers for the six months ended June 30, 2014 and 2013, respectively. DPL has concluded that while a VIE exists under this arrangement, consolidation is not required for this arrangement under the FASB guidance on consolidation of variable interest entities as DPL is not the primary beneficiary.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Operating Revenue	$ 253	$ 271	$ 593	$ 548
Operating Expenses				
Purchased energy	151	154	316	311
Other operation and maintenance	52	58	113	119
Depreciation and amortization	37	32	75	63
Other taxes	1	2	2	6
Deferred electric service costs	(13)	(4)	31	(3)
Total Operating Expenses	228	242	537	496
Operating Income	25	29	56	52
Other Income (Expenses)				
Interest expense	(16)	(18)	(31)	(35)
Other income	1	—	1	—
Total Other Expenses	(15)	(18)	(30)	(35)
Income Before Income Tax Expense	10	11	26	17
Income Tax Expense	4	4	10	1
Net Income	$ 6	$ 7	$ 16	$ 16

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 6	$ 3
Restricted cash equivalents	9	10
Accounts receivable, less allowance for uncollectible accounts of $10 million and $10 million, respectively	176	186
Inventories	27	28
Income taxes and related accrued interest receivable	147	147
Prepaid expenses and other	51	16
Total Current Assets	416	390
OTHER ASSETS		
Regulatory assets	462	569
Prepaid pension expense	101	106
Income taxes and related accrued interest receivable	34	34
Restricted cash equivalents	14	14
Other	11	12
Total Other Assets	622	735
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	2,978	2,901
Accumulated depreciation	(754)	(751)
Net Property, Plant and Equipment	2,224	2,150
TOTAL ASSETS	$3,262	$ 3,275

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 180	$ 138
Current portion of long-term debt	149	148
Accounts payable	21	21
Accrued liabilities	107	105
Accounts payable due to associated companies	14	15
Taxes accrued	16	12
Interest accrued	12	13
Customer deposits	20	22
Other	26	23
Total Current Liabilities	545	497
DEFERRED CREDITS		
Regulatory liabilities	18	57
Deferred income tax liabilities, net	841	833
Investment tax credits	5	5
Other postretirement benefit obligations	35	35
Other	15	14
Total Deferred Credits	914	944
OTHER LONG-TERM LIABILITIES		
Long-term debt	753	753
Transition Bonds issued by ACE Funding	193	214
Total Other Long-Term Liabilities	946	967
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
EQUITY		
Common stock, $3.00 par value, 25,000,000 shares authorized, 8,546,017 shares outstanding	26	26
Premium on stock and other capital contributions	651	651
Retained earnings	180	190
Total Equity	857	867
TOTAL LIABILITIES AND EQUITY	$ 3,262	$ 3,275

The accompanying Notes are an integral part of these Consolidated Financial Statements.

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 16	$ 16
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	75	63
Deferred income taxes	11	21
Changes in:		
Accounts receivable	9	—
Prepaid expenses	(36)	(39)
Regulatory assets and liabilities, net	29	(5)
Accounts payable and accrued liabilities	(4)	13
Pension contributions	—	(30)
Income tax-related prepayments, receivables and payables	4	5
Other assets and liabilities	7	4
Net Cash From Operating Activities	111	48
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(104)	(141)
Department of Energy capital reimbursement	1	—
Net other investing activities	—	3
Net Cash Used By Investing Activities	(103)	(138)
FINANCING ACTIVITIES		
Dividends paid to Parent	(26)	—
Capital contributions from Parent	—	75
Issuances of long-term debt	—	100
Reacquisitions of long-term debt	(20)	(19)
Issuances (repayments) of short-term debt, net	41	(69)
Net other financing activities	—	1
Net Cash (Used by) From Financing Activities	(5)	88
Net Increase (Decrease) in Cash and Cash Equivalents	3	(2)
Cash and Cash Equivalents at Beginning of Period	3	6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6	$ 4
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ —	$ (13)

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
BALANCE, DECEMBER 31, 2013	8,546,017	$ 26	$ 651	$ 190	$867
Net Income	—	—	—	10	10
Dividends on common stock	—	—	—	(26)	(26)
BALANCE, MARCH 31, 2014	8,546,017	26	651	174	851
Net Income	—	—	—	6	6
BALANCE, JUNE 30, 2014	8,546,017	$ 26	$ 651	$ 180	$857

The accompanying Notes are an integral part of these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

ATLANTIC CITY ELECTRIC COMPANY

(1) ORGANIZATION

Atlantic City Electric Company (ACE) is engaged in the transmission and distribution of electricity in southern New Jersey. ACE also provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territory who do not elect to purchase electricity from a competitive energy supplier. Default Electricity Supply is known as Basic Generation Service in New Jersey. ACE is a wholly owned subsidiary of Conectiv, LLC, which is wholly owned by Pepco Holdings, Inc. (Pepco Holdings or PHI).

PHI has entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly-owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly-owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly-owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly-owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on July 29, 2014, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission, the Delaware Public Service Commission, the District of Columbia Public Service Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976; and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). The parties currently anticipate that the closing will occur in the second or third quarter of 2015.

The Merger Agreement may be terminated by each of PHI and Exelon under certain circumstances, including if the Merger is not consummated by July 29, 2015 (subject to extension to October 29, 2015, if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for both PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals (a Regulatory Termination), Exelon will pay PHI a reverse termination fee equal to the purchase price paid up to the date of termination by Exelon to purchase the Preferred Stock, through PHI's redemption of the Preferred Stock for nominal consideration. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

ACE's unaudited consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. Therefore, these consolidated financial statements should be read along with the annual consolidated financial statements included in ACE's annual report on Form 10-K for the year ended December 31, 2013. In the opinion of ACE's management, the unaudited consolidated financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly ACE's financial condition as of June 30, 2014, in accordance with GAAP. The year-end December 31, 2013 consolidated balance sheet included herein was derived from audited consolidated financial statements, but does not include all disclosures required by GAAP. Interim results for the three and six months ended June 30, 2014 may not be indicative of ACE's results that will be realized for the full year ending December 31, 2014.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the consolidated financial statements and accompanying notes. Although ACE believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset impairment evaluations, fair value calculations for derivative instruments, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of loss contingency liabilities for general litigation and auto and other liability claims, and income tax provisions and reserves. Additionally, ACE is subject to legal, regulatory, and other proceedings and claims that arise in the ordinary course of its business. ACE records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Consolidation of Variable Interest Entities

ACE assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests. See Note (13), "Variable Interest Entities," for additional information.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in ACE's gross revenues were zero and $2 million for the three months ended June 30, 2014 and 2013, respectively, and $1 million and $5 million for the six months ended June 30, 2014 and 2013, respectively.

Reclassifications

Certain prior period amounts have been reclassified in order to conform to the current period presentation.

Revision of Prior Period Financial Statements

Operating and Financing Cash Flows

The consolidated statement of cash flows for the six months ended June 30, 2013 has been revised to correctly present changes in book overdraft balances as operating activities (included in Changes in accounts payable and accrued liabilities) rather than financing activities (included previously in Net other financing activities). For the six months ended June 30, 2013, the effect of the revision was to decrease Net cash from operating activities by $1 million from $49 million to $48 million, and increase Net cash from financing activities by $1 million from $87 million to $88 million. The revision was not considered to be material, individually or in the aggregate, to previously issued financial statements.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Liabilities (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, ACE is required to measure such obligations as the sum of the amount it agreed to pay on the basis of its arrangement among co-obligors and any additional amount it expects to pay on behalf of its co-obligors. Adoption of this guidance during the first quarter of 2014 did not have a material impact on ACE's consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance requiring netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The prospective adoption of this guidance at March 31, 2014 resulted in ACE netting liabilities related to uncertain tax positions with deferred tax assets for net operating loss and other carryforwards (included in deferred income tax liabilities, net) and income taxes receivable (including income tax deposits) related to effectively settled uncertain tax positions.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements are effective for ACE beginning January 1, 2017, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2017. Early adoption is not permitted. ACE is currently evaluating the potential impact of this new guidance on its consolidated financial statements and which implementation approach to select.

(5) SEGMENT INFORMATION

ACE operates its business as one regulated utility segment, which includes all of its services as described above.

(6) REGULATORY MATTERS

Rate Proceedings

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings as indicated below.

Bill Stabilization Adjustment

In 2009, ACE proposed in New Jersey the adoption of a bill stabilization adjustment (BSA) mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. The BSA proposal was not approved and there is no BSA proposal currently pending. Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission.

Electric Distribution Base Rates

On March 14, 2014, ACE submitted an application with the NJBPU to increase its electric distribution base rates by approximately $61.7 million (excluding sales and use taxes), based on a requested return on equity (ROE) of 10.25%. The requested rate increase seeks to recover expenses associated with ACE's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. The application requests that the NJBPU put rates into effect by mid-December 2014. The matter has been transmitted by NJBPU to the Office of Administrative Law. Consistent with the procedural schedule for the proceeding, the parties are engaged in settlement negotiations. Absent entering into a settlement agreement that is ultimately approved by the NJBPU, ACE would anticipate that a fully-litigated decision in this proceeding would be issued by the NJBPU in the first quarter of 2015. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue the conclusion of the aforementioned matter, but under the Merger Agreement, ACE is not permitted to initiate or file further electric distribution base rate cases in New Jersey without Exelon's consent.

Update and Reconciliation of Certain Under-Recovered Balances

On March 3, 2014, ACE submitted a petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators (NUGs), (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The net impact of adjusting the charges as proposed is an overall annual rate decrease of approximately $24.5 million (revised to a decrease of approximately $41.1 million on April 16, 2014, based upon an update for actual data through March 2014). In May 2014, the NJBPU approved a stipulation of settlement entered into by the parties in this proceeding providing for an overall annual rate decrease of $41.1 million. The rate decrease, which went into effect on June 1, 2014, will have no effect on ACE's operating income and was placed into effect provisionally subject to a review by the NJBPU of the final underlying costs for reasonableness and prudence. The final order in this proceeding is not expected to be affected by the Merger Agreement.

Service Extension Contributions Refund Order

On July 19, 2013, in compliance with a 2012 Superior Court of New Jersey Appellate Division (Appellate Division) court decision, the NJBPU released an order requiring utilities to issue refunds to persons or entities that paid non-refundable contributions for utility service extensions to certain areas described as "Areas Not Designated for Growth." The order is limited to eligible contributions paid between March 20, 2005 and December 20, 2009. ACE is processing the refund requests that meet the eligibility criteria established in the order as they are received. Although ACE estimates that it received approximately $11 million of contributions between March 20, 2005 and December 20, 2009, it is currently unable to reasonably estimate the amount that it may be required to refund using the eligibility criteria established by the order. Since the July 2013 order was released, ACE has received less than $1 million in refund claims, the validity of which is being investigated by ACE prior to making any such refunds. At this time, ACE does not expect that any such amount refunded will have a material effect on its consolidated financial condition, results of operations or cash flows, as any amounts that may be refunded will generally increase the value of ACE's property, plant and equipment and may ultimately be recovered through depreciation and cost of service. It is anticipated that the NJBPU will commence a rulemaking proceeding to further implement the directives of the Appellate Division decision. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue the conclusion of this matter.

Generic Consolidated Tax Adjustment Proceeding

In January 2013, the NJBPU initiated a generic proceeding to examine whether a consolidated tax adjustment (CTA) should continue to be used, and if so, how it should be calculated in determining a utility's cost of service. Under the NJBPU's current policy, when a New Jersey utility is included in a consolidated group income tax return, an allocated amount of any reduction in the consolidated group's taxes as a result of losses by affiliates is used to reduce the utility's rate base, upon which the utility earns a return. This policy has negatively impacted ACE's base rate case outcomes and ACE's position is that the CTA should be eliminated. A stakeholder process has been initiated by the NJBPU to aid in this examination. On June 18, 2014, NJBPU staff released a Notice of Opportunity to Provide Additional

Information in this proceeding (the June 2014 Notice). The June 2014 Notice invited comments on a staff proposal to modify, but not eliminate, the existing CTA. Responses are due on or before August 18, 2014. No formal schedule has been set by the NJBPU for the remainder of the proceeding or for the issuance of a final decision. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue this matter.

Federal Energy Regulatory Commission

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc., filed a joint complaint with FERC against ACE and its affiliates Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company (DPL), as well as Baltimore Gas and Electric Company. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for ACE and its utility affiliates is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. ACE believes the allegations in this complaint are without merit and is vigorously contesting it. In April 2013, ACE filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that the complaint failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. ACE cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, ACE is permitted, and intends to continue, to pursue the conclusion of this matter.

On June 19, 2014, FERC issued an order in a proceeding in which ACE was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint filed against ACE and its utility affiliates, ACE believes that it is probable that FERC will direct ACE to use this methodology at the time it issues an order addressing the complaint. As a result, ACE applied an estimated ROE based on the two-step methodology announced by FERC for the period over which ACE's transmission revenues would be subject to refund as a result of the challenge, and has recorded an estimated reserve in the second quarter of 2014 related to this matter.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three Standard Offer Capacity Agreements (SOCAs) by order of the NJBPU, each with a different generation company. ACE and the other New Jersey electric distribution companies (EDCs) entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators were dismissed without prejudice subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. On October 11, 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause, and is therefore null and void. On October 21, 2013 a joint motion to stay the Federal district court's decision pending appeal was filed by the NJBPU and one of the SOCA generation companies. In that motion, the NJBPU notified the Federal district court that it would take no action to force implementation of the SOCAs pending the appeal or such other action—such as FERC approval of the SOCAs—that would cure the constitutional issues to the Federal district court's satisfaction. On October 25, 2013, the Federal district court issued an order denying the joint motion to stay and ruling that the SOCAs are void, invalid and unenforceable. The SOCA generation companies and the NJBPU appealed the Federal district court's decision. The U.S. Court of Appeals for the Third Circuit heard the appeal on March 27, 2014, but has not rendered a decision.

One of the three SOCAs was terminated effective July 1, 2013 because of an event of default of the generation company that was a party to the SOCA. The remaining two SOCAs were terminated effective November 19, 2013, as a result of a termination notice delivered by ACE after the Federal district court's October 25, 2013 decision.

Despite the terminated status of the SOCAs, one of the generation companies that was a party to a SOCA filed the SOCA at FERC on June 2, 2014, seeking to have the SOCA accepted under Section 205 of the Federal Power Act. The EDCs intervened in the proceeding and requested that the generation company's filing be rejected on the grounds that the SOCA never came into effect.

In light of the Federal district court order (which has not been stayed pending appeal), ACE derecognized both the derivative assets (liabilities) for the estimated fair value of the SOCAs and the related regulatory liabilities (assets) in the fourth quarter of 2013.

Merger Approval Proceedings

New Jersey

On June 18, 2014, Exelon, PHI and ACE, and certain of their respective affiliates, filed a petition with the NJBPU seeking approval of the Merger. To approve the Merger, the NJBPU must find the Merger is in the public interest, and consider the impact of the Merger on (i) competition, (ii) rates of ratepayers affected by the Merger, (iii) ACE's employees, and (iv) the provision of safe and reliable service at just and reasonable rates. On July 23, 2014, the NJBPU voted to retain this matter, rather than assigning it to an administrative law judge. New Jersey law does not impose any time limit on the NJBPU's review of the Merger, and a procedural schedule for this proceeding has not yet been set.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the Federal Power Act. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. The companies requested that FERC find that the transaction is consistent with the public interest and grant approval within 90 days.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

ACE accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and its other postretirement benefits plan (the Pepco Holdings, Inc. Welfare Plan for Retirees), as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended June 30, 2014 and 2013, before intercompany allocations from the PHI Service Company, were $10 million and $29 million, respectively. ACE's allocated share was $2 million and $5 million for the three months ended June 30, 2014 and 2013, respectively. PHI's pension and other postretirement net periodic benefit cost for the six months ended June 30, 2014 and 2013, before intercompany allocations from the PHI Service Company, were $28 million and $54 million, respectively. ACE's allocated share was $6 million and $10 million for the six months ended June 30, 2014 and 2013, respectively.

In the first quarter of 2013, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan of $30 million. In 2014, ACE has made no such contributions.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and became effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $11 million reduction in ACE's net periodic benefit cost for other postretirement benefits during the six months ended June 30, 2014 when compared to the six months ended June 30, 2013. ACE anticipates approximately 37% of annual net periodic other postretirement benefit costs will be capitalized.

(8) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility is currently August 1, 2018.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion, and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 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 sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate (LIBOR) plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility at June 30, 2014.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of June 30, 2014 and December 31, 2013, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $736 million and $332 million, respectively. ACE's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by Pepco and DPL and the portion of the total capacity being used by PHI.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings.

Commercial Paper

ACE maintains an on-going commercial paper program to address its short-term liquidity needs. As of June 30, 2014, the maximum capacity available under the program was $350 million, subject to available borrowing capacity under the credit facility.

ACE had $180 million of commercial paper outstanding at June 30, 2014. The weighted average interest rate for commercial paper issued by ACE during the six months ended June 30, 2014 was 0.25% and the weighted average maturity of all commercial paper issued by ACE during the six months ended June 30, 2014 was four days.

Other Financing Activities

Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE's Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of June 30, 2014, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.91%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of June 30, 2014.

Bond Payments

In April 2014, Atlantic City Electric Transition Funding LLC (ACE Funding) made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

Bond Retirement

In April 2014, ACE retired, at maturity, $18 million of tax-exempt unsecured variable rate demand bonds issued for the benefit of ACE by the Pollution Control Financing Authority of Salem County.

Financing Activities Subsequent to June 30, 2014

Bond Payments

In July 2014, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

(9) INCOME TAXES

A reconciliation of ACE's consolidated effective income tax rates is as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	(millions of dollars)							
Income tax at federal statutory rate	$ 3	35.0%	$ 4	35.0%	$ 9	35.0%	$ 6	35.0%
Increases (decreases) resulting from:								
State income taxes, net of federal effect	1	10.0%	1	9.1%	2	7.7%	1	5.9%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	1	9.1%	—	—	(9)	(52.9)%
Depreciation	—	—	—	—	(1)	(3.8)%	—	—
Other, net	—	(5.0)%	(2)	(16.8)%	—	(0.4)%	3	17.9%
Consolidated income tax expense	$ 4	40.0%	$ 4	36.4%	$ 10	38.5%	$ 1	5.9%

In the first quarter of 2013, ACE recorded changes in estimates and interest related to uncertain and effectively settled tax positions. On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which ACE is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded an after-tax charge of $377 million in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in ACE recording a $6 million interest benefit in the first quarter of 2013.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the Internal Revenue Service (IRS) issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. In February 2014, the IRS issued revenue procedures that describe how taxpayers should implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. ACE does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its consolidated financial statements.

(10) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

ACE applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ACE utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, ACE utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, ACE's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. ACE's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value Measurements at June 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Cash equivalents and restricted cash equivalents				
Treasury funds	$ 23	$ 23	$ —	$ —
	$ 23	$ 23	$ —	$ —
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 1	$ —	$ 1	$ —
	$ 1	$ —	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2014.

Description	Fair Value Measurements at December 31, 2013 Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
ASSETS				
Cash equivalents and restricted cash equivalents				
Treasury funds	$ 24	$ 24	$ —	$ —
	$ 24	$ 24	$ —	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2013.

ACE classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

A reconciliation of the beginning and ending balances of ACE's fair value measurements using significant unobservable inputs (level 3) for the six months ended June 30, 2013 is shown below:

	Six Months Ended June 30, 2013 Capacity (millions of dollars)
Beginning balance as of January 1	$ (3)
Total gains (losses) (realized and unrealized):	
Included in income	—
Included in accumulated other comprehensive loss	—
Included in regulatory liabilities and regulatory assets	(7)
Purchases	—
Issuances	—
Settlements	—
Transfers in (out) of level 3	—
Ending balance as of June 30	$ (10)

Other Financial Instruments

The estimated fair values of ACE's Long-term debt instruments that are measured at amortized cost in ACE's consolidated financial statements and the associated levels of the estimates within the fair value hierarchy as of June 30, 2014 and December 31, 2013 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. ACE's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt and Transition Bonds issued by ACE Funding (Transition Bonds) categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and ACE reviews the methodologies and results.

The fair value of Long-term debt categorized as level 3 is based on a discounted cash flow methodology using observable inputs, such as the U.S. Treasury yield, and unobservable inputs, such as credit spreads, because quoted prices for the debt or similar debt in active markets were insufficient.

	Fair Value Measurements at June 30, 2014			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$ 989	$ —	$ 761	$ 228
Transition bonds (b)	262	—	262	—
	$1,251	$ —	$ 1,023	$ 228

(a) The carrying amount for Long-term debt was $860 million as of June 30, 2014.
(b) The carrying amount for Transition bonds, including amounts due within one year, was $235 million as of June 30, 2014.

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2013			
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$ 959	$ —	$ 744	$ 215
Transition bonds (b)	285	—	285	—
	$1,244	$ —	$ 1,029	$ 215

(a) The carrying amount for Long-term debt was $860 million as of December 31, 2013.
(b) The carrying amount for Transition bonds, including amounts due within one year, was $255 million as of December 31, 2013.

The carrying amounts of all other financial instruments in the accompanying consolidated financial statements approximate fair value.

(11) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, ACE is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. ACE is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, ACE's contracts with its vendors generally require the vendors to name ACE as an additional insured for the amount at least equal to ACE's self-insured retention. Further, ACE's contracts with its vendors require the vendors to indemnify ACE for various acts and activities that may give rise to claims against ACE. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on ACE's financial condition, results of operations or cash flows. At June 30, 2014, ACE had recorded estimated loss contingency liabilities for general litigation totaling approximately $12 million (including amounts related to the matters specifically described below), and the portion of these estimated loss contingency liabilities in excess of the self-insured retention amount was substantially offset by estimated insurance receivables.

Asbestos Claim

In September 2011, an asbestos complaint was filed in the New Jersey Superior Court, Law Division, against ACE (among other defendants) asserting claims under New Jersey's Wrongful Death and Survival statutes. The complaint, filed by the estate of a decedent who was the wife of a former employee of ACE, alleges that the decedent's mesothelioma was caused by exposure to asbestos brought home by her husband on his work clothes. New Jersey courts have recognized a cause of action against a premise owner in a so-called "take home" case if it can be shown that the harm was foreseeable. In this case, the complaint seeks recovery of an unspecified amount of damages for, among other things, the decedent's past medical expenses, loss of earnings, and pain and suffering between the time of injury and death, and asserts a punitive damage claim. At June 30, 2014, ACE has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of June 30, 2014. However, due to the inherent uncertainty of litigation, ACE is unable to estimate a maximum amount of possible loss because the damages sought are indeterminate and the matter involves facts that ACE believes are distinguishable from the facts of the "take-home" cause of action recognized by the New Jersey courts.

Electrical Contact Injury Claims

In October 2010, a farm combine came into and remained in contact with a primary electric line in ACE's service territory in New Jersey. As a result, two individuals operating the combine received fatal electrical contact injuries. While attempting to rescue those two individuals, another individual sustained third-degree burns to his torso and upper extremities. In September 2012, the individual who received third-degree burns filed suit in New Jersey Superior Court, Salem County. In October 2012, additional suits were filed in the same court by or on behalf of the estates of the deceased individuals. Plaintiffs in each of the cases are seeking indeterminate damages and allege that ACE was negligent in the design, construction, erection, operation and maintenance of its poles, power lines, and equipment, and that ACE failed to warn and protect the public from the foreseeable dangers of farm equipment contacting electric lines. Discovery is ongoing in this matter and the litigation involves a number of other defendants and the filing of numerous cross-claims. ACE has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident will offset ACE's costs associated with the resolution of this matter in excess of ACE's self-insured retention amount. At June 30, 2014, ACE has concluded that a loss is probable with respect to these claims and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of June 30, 2014. ACE has also concluded as of June 30, 2014 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable of substantially the same amount as the loss contingency liability in excess of ACE's self-insured retention amount.

Environmental Matters

ACE is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of ACE, environmental clean-up costs incurred by ACE generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of ACE described below at June 30, 2014 are summarized as follows:

	Legacy Generation - Regulated
	(millions of dollars)
Beginning balance as of January 1	$ 1
Accruals	—
Payments	—
Ending balance as of June 30	1
Less amounts in Other Current Liabilities	—
Amounts in Other Deferred Credits	$ 1

Franklin Slag Pile Site

In November 2008, ACE received a general notice letter from the U.S. Environmental Protection Agency (EPA) concerning the Franklin Slag Pile site in Philadelphia, Pennsylvania, asserting that ACE is a potentially responsible party (PRP) that may have liability for clean-up costs with respect to the site and for the costs of implementing an EPA-mandated remedy. EPA's claims are based on ACE's sale of boiler slag from the B.L. England generating facility, then owned by ACE, to MDC Industries, Inc. (MDC) during the period June 1978 to May 1983. EPA claims that the boiler slag ACE sold to MDC contained copper and lead, which are hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), and that the sales transactions may have constituted an arrangement for the disposal or treatment of hazardous substances at the site, which could be a basis for liability under CERCLA. The EPA letter also states that, as of the date of the letter, EPA's expenditures for response measures at the site have exceeded $6 million. EPA's feasibility study for this site conducted in 2007 identified a range of alternatives for permanent remedial measures with varying cost estimates, and the estimated cost of EPA's preferred alternative is approximately $6 million.

ACE believes that the B.L. England boiler slag sold to MDC was a valuable material with various industrial applications and, therefore, the sale was not an arrangement for the disposal or treatment of any hazardous substances as would be necessary to constitute a basis for liability under CERCLA. ACE intends to contest any claims to the contrary made by EPA. In a May 2009 decision arising under CERCLA, which did not involve ACE, the U.S. Supreme Court rejected an EPA argument that the sale of a useful product constituted an arrangement for disposal or treatment of hazardous substances. While this decision supports ACE's position, at this time ACE cannot predict how EPA will proceed with respect to the Franklin Slag Pile site, or what portion, if any, of the Franklin Slag Pile site response costs EPA would seek to recover from ACE. Costs to resolve this matter are not expected to be material and are expensed as incurred.

Ward Transformer Site

In April 2009, a group of PRPs with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including ACE, based on its alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including ACE) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the Federal district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The Federal district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. ACE has concluded that a loss is reasonably possible with respect to this matter, but is unable to estimate an amount or range of reasonably possible losses to which it may be exposed. ACE does not believe that it had extensive business transactions, if any, with the Ward Transformer site.

(12) RELATED PARTY TRANSACTIONS

PHI Service Company provides various administrative and professional services to PHI and its regulated and unregulated subsidiaries, including ACE. The cost of these services is allocated in accordance with cost allocation methodologies set forth in the service agreement using a variety of factors, including the subsidiaries' share of employees, operating expenses, assets and other cost methods. These intercompany transactions are eliminated by PHI in consolidation and no profit results from these transactions at PHI. PHI Service Company costs directly charged or allocated to ACE for the three months ended June 30, 2014 and 2013 were approximately $31 million and $28 million, respectively. PHI Service Company costs directly charged or allocated to ACE for the six months ended June 30, 2014 and 2013 were approximately $60 million and $59 million, respectively.

In addition to the PHI Service Company charges described above, ACE's consolidated financial statements include the following related party transactions in the consolidated statements of income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(millions of dollars)			
Meter reading services provided by Millennium Account Services LLC (an ACE affiliate) (a)	$ (1)	$ (1)	$ (2)	$ (2)

(a) Included in Other operation and maintenance expense.

As of June 30, 2014 and December 31, 2013, ACE had the following balances on its consolidated balance sheets due to related parties:

	June 30, 2014	December 31, 2013
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (14)	$ (15)
Total	$ (14)	$ (15)

(a) Included in Accounts payable due to associated companies.

(13) VARIABLE INTEREST ENTITIES

ACE is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if ACE or a subsidiary is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. ACE performed a qualitative analysis to determine whether a variable interest provided a controlling financial interest in any of its VIEs at June 30, 2014, as described below.

ACE Power Purchase Agreements

ACE is a party to three power purchase agreements (PPAs) with unaffiliated NUGs totaling 459 megawatts. One of the agreements ends in 2016 and the other two end in 2024. ACE was not involved in the creation of these contracts and has no equity or debt invested in these entities. In performing its' VIE analysis, ACE has been unable to obtain sufficient information to determine whether these three entities were variable interest entities or if ACE was the primary beneficiary. As a result, ACE has applied the scope exemption from the consolidation guidance.

Because ACE has no equity or debt invested in the NUGs, the maximum exposure to loss relates primarily to any above-market costs incurred for power. Due to unpredictability in the PPAs pricing for purchased energy, ACE is unable to quantify the maximum exposure to loss. The power purchase costs are recoverable from ACE's customers through regulated rates. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the three months ended June 30, 2014 and 2013, were approximately $54 million and $53 million, respectively, of which approximately $49 million and $48 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the six months ended June 30, 2014 and 2013, were approximately $126 million and $107 million, respectively, of which approximately $108 million and $103 million, respectively, consisted of power purchases under the PPAs.

ACE Funding

In 2001, ACE established ACE Funding solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. The proceeds of the sale of each series of Transition Bonds were transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect a non-bypassable Transition Bond Charge (representing revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees) from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on the Transition Bonds and related taxes, expenses and fees (Bondable Transition Property). The assets of ACE Funding, including the Bondable Transition Property, and the Transition Bond Charges collected from ACE's customers, are not available to creditors of ACE. The holders of Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding, and PHI and ACE consolidate ACE Funding in their consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this item is contained herein, as follows:

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pepco Holdings, Inc.

General Overview

PHI, a Delaware corporation incorporated in 2001, is a holding company that, through its regulated public utility subsidiaries, is engaged primarily in the transmission, distribution and default supply of electricity, and, to a lesser extent, the distribution and supply of natural gas (Power Delivery). Through Pepco Energy Services, Inc. and its subsidiaries (collectively, Pepco Energy Services), PHI provides energy savings performance contracting services, underground transmission and distribution construction and maintenance services and steam and chilled water under long-term contracts. For additional discussion, see "Pepco Energy Services" below.

Each of Power Delivery and Pepco Energy Services constitutes a separate segment for financial reporting purposes. Through its wholly-owned subsidiary Potomac Capital Investment Corporation (PCI), PHI maintained a portfolio of cross-border energy lease investments. PHI completed the termination of its interests in its cross-border energy lease investments during 2013. As a result, the cross-border energy lease investments, which comprised substantially all of the operations of the Other Non-Regulated segment, are being accounted for as discontinued operations. The remaining operations of the Other Non-Regulated segment, which no longer meet the definition of a separate segment for financial reporting purposes, are being included in Corporate and Other.

The following table sets forth the percentage contributions to consolidated operating revenue and operating income from continuing operations attributable to PHI segments for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Percentage of Consolidated Operating Revenue				
Power Delivery	93%	96%	94%	95%
Pepco Energy Services	7%	5%	6%	5%
Corporate and Other	—	(1)%	—	—
Percentage of Consolidated Operating Income				
Power Delivery	105%	97%	101%	95%
Pepco Energy Services	1%	1%	1%	2%
Corporate and Other	(6)%	2%	(2)%	3%
Percentage of Power Delivery Operating Revenue				
Power Delivery Electric	97%	97%	95%	95%
Power Delivery Gas	3%	3%	5%	5%

Agreement and Plan of Merger

PHI has entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated July 18, 2014 (the Merger Agreement), with Exelon and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly-owned subsidiary of Exelon (Merger Sub), providing for the Merger, with PHI surviving the Merger as an indirect, wholly-owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly-owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly-owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on July 29, 2014, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from FERC, the Federal Communications Commission, the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commision (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976; and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). The parties currently anticipate that the closing will occur in the second or third quarter of 2015.

The Merger Agreement may be terminated by each of PHI and Exelon under certain circumstances, including if the Merger is not consummated by July 29, 2015 (subject to extension to October 29, 2015, if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for both PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Power Delivery

Power Delivery Electric consists primarily of the transmission, distribution and default supply of electricity, and Power Delivery Gas consists of the delivery and supply of natural gas.

The Pepco, DPL and ACE service territories are located within a corridor extending from the District of Columbia to southern New Jersey. These service territories are economically diverse and include key industries that contribute to the regional economic base:

- Commercial activities in the region include banking and other professional and medical services, government and education, insurance, shopping malls, casinos, tourism and transportation.
- Industrial activities in the region include chemical, glass, pharmaceutical, steel manufacturing, food processing and oil refining.

Each utility comprising Power Delivery is a regulated public utility in the jurisdictions that comprise its service territory. Each utility is responsible for the distribution of electricity and, in the case of DPL, natural gas in its service territory, for which it is paid tariff rates established by the applicable local public service commission in each jurisdiction. Each utility also supplies electricity at regulated rates to retail customers in its service territory who do not elect to purchase electricity from a competitive energy supplier. The regulatory term for this supply service is standard offer service (SOS) in Delaware, the District of Columbia and Maryland, and Basic Generation Service (BGS) in New Jersey. These supply service obligations are referred to generally as Default Electricity Supply.

Each of Pepco, DPL and ACE is responsible for the transmission of wholesale electricity into and across its service territory. The rates each utility is permitted to charge for the wholesale transmission of electricity are regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The profitability of Power Delivery depends on its ability to recover costs and earn a reasonable return on its capital investments through the rates it is permitted to charge. Operating results also can be affected by economic conditions generally, the level of commercial activity affecting a region, industry or business sector within a service territory, energy prices, the impact of energy efficiency measures on customer usage of electricity and weather.

Power Delivery's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco and DPL in Maryland and of Pepco in the District of Columbia, revenue is not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) was implemented that provides for a fixed distribution charge per customer rather than a charge based upon energy usage. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from retail customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A comparable revenue decoupling mechanism for DPL electricity and natural gas customers in Delaware is under consideration by the DPSC.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment (an adjustment equal to the amount by which revenue from distribution sales differs from the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer) is recorded representing either (i) a positive adjustment equal to the amount by which revenue from retail distribution sales falls short of the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer.

PHI's utility subsidiaries devote a substantial portion of their total capital expenditures to improving the reliability of their electrical transmission and distribution systems and replacing aging infrastructure throughout their service territories. These activities include:

- identifying and upgrading under-performing feeder lines;
- adding new facilities to support load;
- installing distribution automation systems on both the overhead and underground network systems; and
- rejuvenating and replacing underground residential cables.

Power Delivery Initiatives and Activities

Smart Grid Initiatives

PHI's utility subsidiaries are engaged in transforming the power grid that they own and operate into a "smart grid," a network of automated digital devices capable of collecting and communicating large amounts of real-time data.

A central component of the smart grid is AMI, a system that collects, measures and analyzes energy usage data from advanced digital meters, known as "smart meters." Also critical to the operation of the smart grid is distribution automation technology, which is comprised of automated devices that have internal intelligence and can be controlled remotely to better manage power flow and restore service quickly and more safely. Both the AMI system and distribution automation are enabled by advanced technology that communicates with devices installed on the energy delivery system and transmits energy usage data to the host utility. The implementation of the AMI system and distribution automation involves an integration of technologies provided by multiple vendors.

The DCPSC, the MPSC and the DPSC have approved the creation by PHI's utility subsidiaries of regulatory assets to defer AMI costs between rate cases and to defer carrying charges on the deferred costs. Thus, these costs will be recovered in the future through base rates; however, for AMI costs incurred by Pepco in Maryland with respect to test years after 2011, pursuant to an MPSC order, the recovery of such costs will be allowed when Pepco demonstrates that the AMI system is cost-effective. The MPSC's July 2013 order in Pepco's November 2012 electric distribution base rate application excluded the cost of AMI meters from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system. As a result, costs for AMI meters incurred with respect to the 2012 test year and beyond will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system that are deferred and on which a carrying charge is deferred, but only until such cost effectiveness has been demonstrated and such costs are included in rates.

In 2010, two of PHI's utility subsidiaries were granted cash awards in the aggregate amount of $168 million by the U.S. Department of Energy to support their smart grid initiatives.

- Pepco was awarded $149 million for AMI, direct load control, distribution automation and communications infrastructure, of which $148 million has been received through June 30, 2014.
- ACE was awarded $19 million for direct load control, distribution automation and communications infrastructure, of which $19 million has been received through June 30, 2014.

Mitigation of Regulatory Lag

An important factor in the ability of PHI's utility subsidiaries to earn their authorized ROE is the willingness of applicable public service commissions to adequately address the shortfall in revenues in a utility's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." Pepco, DPL and ACE are currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than their revenue growth.

In an effort to minimize the effects of regulatory lag, PHI's utility subsidiaries had been filing electric distribution base rate cases every nine to twelve months in each of their jurisdictions, pursuing alternative ratemaking mechanisms, evaluating potential reductions in planned capital expenditures, and discussing with the regulatory community and other stakeholders the changing regulatory model economics that are causing regulatory lag.

As further described in "Management's Discussion of Analysis of Financial Condition and Results of Operations—General Overview—Agreement and Plan of Merger," PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings. In addition, the regulatory commissions may seek to suspend or delay one or more of the ongoing proceedings as a result of the Merger Agreement.

MAPP Settlement Agreement

On February 28, 2014, FERC issued an order approving the settlement agreement submitted by Pepco and DPL in connection with Pepco's and DPL's proceeding seeking recovery of approximately $88 million in abandonment costs related to the Mid-Atlantic Power Pathway (MAPP) project. PHI had been directed by PJM to construct the MAPP project, a 152-mile high-voltage interstate transmission line, and was subsequently directed by PJM to cancel it. The abandonment costs sought for recovery were subsequently reduced to $82 million from write-offs of certain disallowed costs in 2013 and transfers of materials to inventories for use on other projects. Under the terms of the FERC-approved settlement agreement, Pepco and DPL will receive $80.5 million of transmission revenues over a three-year period, which began on June 1, 2013, and will retain title to all real property and property rights acquired in connection with the MAPP project, which had an estimated fair value of $8 million. The FERC-approved settlement agreement resolves all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project, and the terms of the settlement agreement are not subject to modification through any other FERC proceeding. As of June 30, 2014, PHI had a regulatory asset related to the MAPP abandonment costs of approximately $46 million, net of amortization, and land of $8 million. PHI expects to recognize pre-tax income related to the MAPP abandonment costs of $3 million in 2014 and $1 million in 2015.

Transmission ROE Challenge

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc. (DEMEC), filed a joint complaint with FERC against Pepco, DPL and ACE, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. PHI, Pepco, DPL and ACE believe the allegations in this complaint are without merit and are vigorously contesting it. In April 2013, Pepco, DPL and ACE filed their answer to this complaint, requesting that FERC dismiss the complaint against them on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. PHI cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, PHI is permitted, and will continue, to pursue the conclusion of this matter.

On June 19, 2014, FERC issued an order in a proceeding in which the PHI utilities were not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint, Pepco, DPL and ACE believe that it is probable that FERC will direct each utility to use this methodology at the time it issues an order addressing the complaint. As a result, Pepco, DPL and ACE applied an estimated ROE based on the two-step methodology announced by FERC for the period over which each of their transmission revenues would be subject to refund as a result of the challenge, and have recorded estimated reserves in the second quarter of 2014 related to this matter.

<u>Pepco Energy Services</u>

Pepco Energy Services is focused on growing its energy savings business and its underground transmission and distribution construction business while managing its thermal assets in Atlantic City. The energy savings business focuses on developing, building and operating energy savings performance contracting solutions primarily for federal, state and local government customers. After a significant slowdown in 2012, the energy savings market improved in 2013, however the market has not returned to the level of activity prior to 2012. The market is expected to continue to improve as the long-term fundamentals of the energy savings business remain strong. Pepco Energy Services' underground transmission and distribution construction business focuses on providing construction and maintenance services for electric power utilities in North America.

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At June 30, 2014, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $255 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects. These guarantees totaled $218 million at June 30, 2014.

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. Pepco Energy Services has determined that it will pursue the demolition of the Benning Road generation facility and realize the scrap metal salvage value of the facility. The demolition of the facility commenced in the fourth quarter of 2013 and is expected to be completed in the first quarter of 2015. Pepco Energy Services will recognize the salvage proceeds associated with the scrap metals at the facility as realized.

Revenues associated with Pepco Energy Services' combined heat and power thermal generating plant and operation in Atlantic City are derived from long-term contracts with a few major customers in the Atlantic City hotel and casino industry. The Atlantic City hotel and casino industry has been experiencing overcapacity and a decrease in gaming revenues, as well as competition from casinos that have been recently opened in nearby markets. This industry also faces potential competition from new casinos being constructed in nearby markets. In July 2014, a significant customer of this thermal operation reported that it is considering closure if it does not find a suitable buyer for its facilities. Future developments with respect to this customer may require Pepco Energy Services to perform an impairment analysis of the thermal operation and certain related assets with an aggregate carrying value as of June 30, 2014 of approximately $74 million. If these assets are determined to be impaired, Pepco Energy Services would reduce the carrying value of these assets by the amount of the impairment and record a corresponding non-cash charge to earnings, which could be material. Moreover, such a closure by this customer could reduce Pepco Energy Services' future earnings associated with the thermal operation.

Corporate and Other

Corporate and other includes the remaining operations of the former Other Non-regulated segment, certain parent company transactions including goodwill, interest expense on parent company debt, merger-related costs and inter-company eliminations.

Between 1990 and 1999, PCI entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. After evaluating events that took place during the first quarter of 2013, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of all relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances. The remaining operations of the former Other Non-Regulated segment are now included in Corporate and Other.

Discontinued Operations

In this Management's Discussion and Analysis of Financial Condition and Results of Operations, all references to PHI's segments and continuing operations exclude the following discontinued operations.

Cross-Border Energy Lease Investments

Through its subsidiary PCI, PHI held a portfolio of cross-border energy lease investments. During 2013, PHI completed the termination of its interest in its cross-border energy lease investments and, as a result, these investments are being accounted for as discontinued operations.

As discussed in Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," to the consolidated financial statements of PHI, PHI is involved in ongoing litigation with the IRS concerning certain benefits associated with previously held investments in cross-border energy leases. On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that its tax position with respect to the benefits associated with its cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes, and PHI recorded non-cash after-tax charges of $323 million (after-tax) in the first quarter of 2013 and $6 million (after-tax) in the second quarter of 2013, consisting of the following components:

- A non-cash pre-tax charge of $373 million ($313 million after-tax) to reduce the carrying value of these cross-border energy lease investments under Financial Accounting Standards Board (FASB) guidance on leases (Accounting Standards Codification (ASC) 840). This pre-tax charge was originally recorded in the consolidated statements of income (loss) as a reduction in operating revenue and is now reflected in loss from discontinued operations, net of income taxes.

- A non-cash charge of $16 million after-tax to reflect the anticipated additional net interest expense under FASB guidance for income taxes (ASC 740), related to estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed. This after-tax charge was originally recorded in the consolidated statements of income (loss) as an increase in income tax expense and is now reflected in loss from discontinued operations, net of income taxes. The after-tax interest charge for PHI on a consolidated basis was $70 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in the recognition of a $12 million interest benefit for the Power Delivery segment and interest expense of $16 million for PCI and $66 million for Corporate and Other, respectively.

Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services

In December 2009, PHI announced the wind-down of the retail energy supply component of the Pepco Energy Services business which was comprised of the retail electric and natural gas supply businesses. Pepco Energy Services implemented the wind-down by not entering into any new retail electric or natural gas supply contracts while continuing to perform under its existing retail electric and natural gas supply contracts through their respective expiration dates. On March 21, 2013, Pepco Energy Services entered into an agreement whereby a third party assumed all the rights and obligations of the remaining retail natural gas supply customer contracts, and the associated supply obligations, inventory and derivative contracts. The transaction was completed on April 1, 2013. In addition, Pepco Energy Services completed the wind-down of its retail electric supply business in the second quarter of 2013 by terminating its remaining customer supply and wholesale purchase obligations beyond June 30, 2013.

The operations of Pepco Energy Services' retail electric and natural gas supply businesses have been classified as discontinued operations and are no longer a part of the Pepco Energy Services segment for financial reporting purposes.

Earnings Overview

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

	2014	2013	Change
		(millions of dollars)	
Power Delivery	$ 71	$ 56	$ 15
Pepco Energy Services	2	1	1
Corporate and Other	(20)	(4)	(16)
Net Income from Continuing Operations	53	53	—
Discontinued Operations	—	(11)	11
Total PHI Net Income	$ 53	$ 42	$ 11

Net income from continuing operations for the three months ended June 30, 2014 was $53 million, or $0.21 per share, compared to $53 million, or $0.21 per share, for the three months ended June 30, 2013.

Net income from continuing operations for the three months ended June 30, 2014 included the expenses set forth below in Corporate and Other, which are presented net of related federal and state income taxes and are in millions of dollars:

•	Incremental merger-related transaction costs (not tax-deductible)	$ 14

Excluding the item listed above for the three months ended June 30, 2014, net income from continuing operations would have been $67 million, or $0.27 per share.

PHI discloses net income from continuing operations and related per share data excluding this item, which are non-GAAP measures, because management believes that this item is not representative of PHI's ongoing business operations. Management uses this information, and believes that such information is useful to investors, in evaluating PHI's period-over-period performance. The inclusion of this disclosure is intended to complement, and should not be considered as an alternative to, PHI's reported net income from continuing operations and related per share data in accordance with accounting principles generally accepted in the United States of America GAAP.

Net loss from discontinued operations was $11 million, or $0.04 per share for the three months ended June 30, 2013.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $15 million increase in earnings was primarily due to the following:

- An increase of $17 million from electric distribution base rate increases (Pepco in the District of Columbia and Maryland, DPL in Maryland and Delaware and ACE in New Jersey).
- An increase of $6 million due to lower other operation and maintenance expense primarily associated with lower pension/other postretirement benefit (OPEB) costs and higher capitalized labor.
- An increase of $5 million from network service transmission revenues primarily due to increased rates, partially offset by the amortization of Mid-Atlantic Power Pathway (MAPP) abandonment costs and the establishment of a reserve related to the FERC ROE complaint.
- An increase of $2 million primarily due to Pepco customer growth.
- An increase of $2 million related to a gain recorded in 2014 associated with the condemnation of certain Pepco transmission property.
- A decrease of $4 million due to higher depreciation and amortization expense, primarily resulting from increases in plant investment and regulatory assets, partially offset by lower depreciation rates.
- A decrease of $4 million due to incremental merger-related integration costs.
- A decrease of $3 million associated with Default Electricity Supply margins for ACE.
- A decrease of $2 million primarily due to lower sales from colder spring weather.

Corporate and Other's $16 million increase in net loss was primarily due to incremental merger-related transaction costs.

Discussion of Discontinued Operations Variance:

Net loss from discontinued operations for the three months ended June 30, 2014 decreased by $11 million primarily as a result of the following:

- A loss of $9 million as a result of the early termination of certain cross-border energy leases in 2013.
- A charge of $6 million in the second quarter of 2013 for a change in estimate associated with state income taxes related to the reduction of the carrying value of the cross-border energy lease investments recorded in the first quarter of 2013.
- A decrease in earnings of $4 million in 2014 from the discontinued Pepco Energy Services retail electric and natural gas supply business.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

	2014	2013	Change
		(millions of dollars)	
Power Delivery	$150	$ 114	$ 36
Pepco Energy Services	2	4	(2)
Corporate and Other	(24)	(176)	152
Net Income (Loss) from Continuing Operations	128	(58)	186
Discontinued Operations	—	(330)	330
Total PHI Net Income (Loss)	$128	$(388)	$ 516

Net income from continuing operations for the six months ended June 30, 2014 was $128 million, or $0.51 per share, compared to a loss of $58 million, or $0.24 per share, for the six months ended June 30, 2013.

Net income from continuing operations for the six months ended June 30, 2014 included the expenses set forth below in Corporate and Other, which are presented net of related federal and state income taxes and are in millions of dollars:

- Incremental merger-related transaction costs (not tax-deductible) $ 14

Excluding the item listed above for the six months ended June 30, 2014, net income from continuing operations would have been $142 million, or $0.57 per share.

Net income from continuing operations for the six months ended June 30, 2013 included the charges set forth below in Corporate and Other, which are presented, where applicable, net of related federal and state income taxes and are in millions of dollars:

- Charge to establish valuation allowances related to certain PCI deferred tax assets $ 101
- Charge to reflect the anticipated additional interest expense on estimated federal and state income tax obligations allocated to Corporate and Other (as if it were a separate taxpayer) resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments ($102 million pre-tax) $ 66

Excluding the items listed above for the six months ended June 30, 2013, net income from continuing operations would have been $109 million, or $0.45 per share.

PHI discloses net income from continuing operations and related per share data excluding these items, which are non-GAAP measures, because management believes that these items are not representative of PHI’s ongoing business operations. Management uses this information, and believes that such information is useful to investors, in evaluating PHI’s period-over-period performance. The inclusion of this disclosure is intended to complement, and should not be considered as an alternative to, PHI’s reported net income from continuing operations and related per share data in accordance with GAAP.

Net loss from discontinued operations was $330 million, or $1.36 per share, for the six months ended June 30, 2013.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $36 million increase in earnings was primarily due to the following:

- An increase of $30 million from electric distribution base rate increases (Pepco in the District of Columbia and Maryland, DPL in Maryland and Delaware and ACE in New Jersey).
- An increase of $14 million due to lower other operation and maintenance expense, primarily related to lower pension/OPEB costs, higher system maintenance in 2013, higher capitalized labor, and the allowed recovery in 2014 of certain previously expensed rate case costs in accordance with a District of Columbia rate order.
- An increase of $7 million from network service transmission revenues primarily due to increased rates, partially offset by the amortization of MAPP abandonment costs and the establishment of a reserve related to the FERC ROE complaint.
- An increase of $7 million primarily due to Pepco and DPL customer growth.
- An increase of $5 million related to a gain recorded in 2014 associated with the condemnation of certain Pepco transmission properties.
- An increase of $4 million primarily due to higher sales from colder winter weather, partially offset by lower sales from colder spring weather.
- A decrease of $12 million due to higher depreciation and amortization expense, primarily resulting from increases in plant investment and regulatory assets, partially offset by lower depreciation rates.
- A decrease of $9 million associated with higher interest benefits recorded in 2013 related to uncertain and effectively settled tax positions.
- A decrease of $5 million associated with Default Electricity Supply margins for ACE.
- A decrease of $4 million due to incremental merger-related integration costs.

Corporate and Other's $152 million decrease in net loss was primarily due to the following:

- An after-tax charge of $101 million in 2013 to establish valuation allowances against certain PCI deferred tax assets.
- An after-tax charge of $66 million in 2013 to reflect the anticipated additional interest expense allocated to Corporate and Other related to changes in PHI's consolidated estimated federal and state income tax obligations resulting from the change in assessment regarding the tax benefits related to the cross-border energy lease investments.
- After-tax charges of $14 million in 2014 due to incremental merger-related transaction costs.

Discussion of Discontinued Operations Variance:

Net loss from discontinued operations for the six months ended June 30, 2014 decreased by $330 million primarily as a result of the following:

- An aggregate after-tax charge of $313 million recorded in 2013 to reduce the carrying value of PCI's cross-border energy lease investments ($373 million pre-tax).
- An after-tax charge of $16 million recorded in 2013 to reflect the anticipated additional interest expense on estimated federal and state income tax obligations allocated to PCI (as if it were a separate taxpayer) resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments ($25 million pre-tax).

- A loss of $9 million as a result of the early termination of certain cross-border energy leases in 2013.
- A decrease in earnings of $4 million in 2014 from the discontinued Pepco Energy Services retail electric and natural gas supply business.

Consolidated Results of Operations

The following results of operations discussion compares the three months ended June 30, 2014 to the three months ended June 30, 2013. All amounts in the tables (except sales and customers) are in millions of dollars.

Continuing Operations

Operating Revenue

A detail of the components of PHI's consolidated operating revenue is as follows:

	2014	2013	Change
Power Delivery	$1,040	$1,006	$ 34
Pepco Energy Services	79	49	30
Corporate and Other	(2)	(4)	2
Total Operating Revenue	$1,117	$1,051	$ 66

Power Delivery

The following table categorizes Power Delivery's operating revenue by type of revenue.

	2014	2013	Change
Regulated T&D Electric Revenue	$ 547	$ 508	$ 39
Default Electricity Supply Revenue	451	453	(2)
Other Electric Revenue	14	16	(2)
Total Electric Operating Revenue	1,012	977	35
Regulated Gas Revenue	25	24	1
Other Gas Revenue	3	5	(2)
Total Gas Operating Revenue	28	29	(1)
Total Power Delivery Operating Revenue	$1,040	$1,006	$ 34

Regulated Transmission and Distribution (T&D) Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, by PHI's utility subsidiaries to customers within their service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that PHI's utility subsidiaries receive as transmission owners from PJM at rates regulated by FERC. Transmission rates are updated annually based on FERC-approved formula methodology.

Default Electricity Supply Revenue is the revenue received from the supply of electricity by PHI's utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive energy supplier. The costs related to Default Electricity Supply are included in Fuel and Purchased Energy. Default Electricity Supply Revenue also includes revenue from non-bypassable transition bond charges (Transition Bond Charges) that ACE receives, and pays to Atlantic City Electric Transition Funding LLC (ACE Funding), to fund the principal and interest payments on Transition Bonds issued by ACE Funding (Transition Bonds), and revenue in the form of transmission enhancement credits that PHI utility subsidiaries receive as transmission owners from PJM for approved regional transmission expansion plan costs.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated Gas Revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates.

Other Gas Revenue consists of DPL's off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Regulated T&D Electric

	2014	2013	Change
Regulated T&D Electric Revenue			
Residential	$ 185	$ 170	$ 15
Commercial and industrial	256	241	15
Transmission and other	106	97	9
Total Regulated T&D Electric Revenue	$ 547	$ 508	$ 39

	2014	2013	Change
Regulated T&D Electric Sales (Gigawatt hours (GWh))			
Residential	3,616	3,567	49
Commercial and industrial	7,504	7,553	(49)
Transmission and other	55	52	3
Total Regulated T&D Electric Sales	11,175	11,172	3

	2014	2013	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,654	1,641	13
Commercial and industrial	199	199	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,855	1,842	13

Regulated T&D Electric Revenue increased by $39 million primarily due to:

- An increase of $26 million due to electric distribution base rate increases (Pepco in the District of Columbia effective March 2014, and in Maryland effective July 2013; DPL in Maryland effective September 2013, and in Delaware effective October 2013; ACE effective July 2013).
- An increase of $6 million in transmission revenue resulting from higher rates effective June 1, 2014 and June 1, 2013 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE complaint.
- An increase of $5 million due to an EmPower Maryland (a Maryland demand-side management program for Pepco and DPL) rate increase effective February 2014 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $4 million due to Pepco and DPL customer growth in 2014, primarily in the residential class.

- An increase of $1 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $1 million in capacity revenue as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by a decrease of $4 million due to lower sales primarily as a result of milder weather during the 2014 spring months, as compared to 2013.

Default Electricity Supply

	2014	2013	Change
Default Electricity Supply Revenue			
Residential	$276	$286	$ (10)
Commercial and industrial	132	129	3
Other	43	38	5
Total Default Electricity Supply Revenue	$451	$453	$ (2)

Other Default Electricity Supply Revenue consists primarily of (i) revenue from the resale by ACE in the PJM regional transmission organization (PJM RTO) market of energy and capacity purchased under contracts with unaffiliated non-utility generators (NUGs), and (ii) revenue from transmission enhancement credits.

	2014	2013	Change
Default Electricity Supply Sales (GWh)			
Residential	2,913	2,847	66
Commercial and industrial	1,254	1,224	30
Other	10	11	(1)
Total Default Electricity Supply Sales	4,177	4,082	95

	2014	2013	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,368	1,343	25
Commercial and industrial	126	126	—
Other	—	—	—
Total Default Electricity Supply Customers	1,494	1,469	25

Default Electricity Supply Revenue decreased by $2 million primarily due to:

- A net decrease of $13 million as a result of lower ACE and DPL Default Electricity Supply rates, partially offset by higher Pepco rates.
- A decrease of $8 million due to lower sales primarily as a result of milder weather during the 2014 spring months, as compared to the same period in 2013.
- A decrease of $1 million due to lower Pepco and DPL revenue from transmission enhancement credits.

The aggregate amount of these decreases was partially offset by:

- An increase of $9 million due to higher sales, primarily as a result of customer migration from competitive suppliers.
- A net increase of $6 million due to higher DPL and Pepco non-weather related average customer usage, partially offset by lower usage at ACE.
- An increase of $5 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.

The variances described above with respect to Default Electricity Supply Revenue include the effects of a reduction of $7 million in ACE's BGS unbilled revenue resulting primarily from lower usage in the unbilled revenue period at June 30, 2014 as compared to the corresponding period at June 30 2013. Such a decrease in ACE's BGS unbilled revenue has the effect of directly decreasing the profitability of ACE's Default Electricity Supply business ($4 million decrease in net income) as these unbilled revenues are not included in the deferral calculation until they are billed to customers under the BGS terms approved by the NJBPU.

Regulated Gas

	2014	2013	Change
Regulated Gas Revenue			
Residential	$ 14	$ 14	$ —
Commercial and industrial	9	7	2
Transportation and other	2	3	(1)
Total Regulated Gas Revenue	$ 25	$ 24	$ 1

	2014	2013	Change
Regulated Gas Sales (million cubic feet)			
Residential	937	887	50
Commercial and industrial	907	608	299
Transportation and other	1,282	1,454	(172)
Total Regulated Gas Sales	3,126	2,949	177

	2014	2013	Change
Regulated Gas Customers (in thousands)			
Residential	117	115	2
Commercial and industrial	9	10	(1)
Transportation and other	—	—	—
Total Regulated Gas Customers	126	125	1

Regulated Gas Revenue increased by $1 million primarily due to:

- An increase of $4 million due to higher non-weather related average customer usage.
- An increase of $1 million due to a distribution rate increase effective July 2013.

The aggregate amount of these increases was partially offset by:

- A decrease of $3 million due to a Gas Cost Rate (GCR) decrease effective November 2013.
- A decrease of $1 million due to lower sales primarily as a result of milder weather during the spring months of 2014 as compared to 2013.

Other Gas Revenue

Other Gas Revenue decreased by $2 million primarily due to lower average prices and lower volumes for off-system sales to electric generators and gas marketers.

Pepco Energy Services

Pepco Energy Services' operating revenue increased by $30 million primarily due to:

- An increase of $17 million primarily in energy savings construction activities.
- An increase of $9 million in underground transmission and distribution construction activities.
- An increase of $3 million associated with the thermal business in Atlantic City.

Operating Expenses

Fuel and Purchased Energy and Other Services Cost of Sales

A detail of PHI's consolidated Fuel and Purchased Energy and Other Services Cost of Sales is as follows:

	2014	2013	Change
Power Delivery	$461	$447	$ 14
Pepco Energy Services	62	35	27
Corporate and Other	1	(1)	2
Total	$524	$481	$ 43

Power Delivery

Power Delivery's Fuel and Purchased Energy consists of the cost of electricity and natural gas purchased by its utility subsidiaries to fulfill their respective Default Electricity Supply and Regulated Gas obligations and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of natural gas purchased for off-system sales. Fuel and Purchased Energy expense increased by $14 million primarily due to:

- An increase of $28 million in deferred electricity expense primarily due to lower costs associated with Pepco and DPL Default Electricity Supply contracts, which resulted in a higher rate of recovery of Default Electricity Supply costs.
- An increase of $17 million primarily due to customer migration from competitive suppliers.

The aggregate amount of these increases was partially offset by:

- A decrease of $22 million due to lower average electricity costs under Pepco and DPL Default Electricity Supply contracts and ACE BGS contracts.
- A decrease of $6 million due to lower electricity sales primarily as a result of milder weather during the 2014 spring months, as compared to the same period in 2013.
- A decrease of $3 million in the cost of gas purchases for off-system sales as a result of lower volumes.

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales increased by $27 million primarily due to:

- An increase of $17 million primarily associated with increased energy savings construction activity.
- An increase of $10 million associated with increased underground transmission and distribution construction activities.

Other Operation and Maintenance

A detail of PHI's Other Operation and Maintenance expense is as follows:

	2014	2013	Change
Power Delivery	$210	$217	$ (7)
Pepco Energy Services	12	10	2
Corporate and Other	(1)	(15)	14
Total	$221	$212	$ 9

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $7 million primarily due to:

- A decrease of $4 million due to higher capitalized labor.
- A decrease of $3 million in bad debt expenses and costs of the New Jersey Societal Benefit Program (a New Jersey statewide public interest program that is intended to benefit low income customers and address other public policy goals) that are deferred and recoverable (offset in Deferred Electric Service Costs).

These decreases were partially offset by an increase of $1 million in incremental merger-related integration costs, partially offset by lower pension and other postretirement benefit expenses.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services increased by $2 million primarily due to repair and maintenance costs at its thermal business in Atlantic City and the demolition of the Benning Road generation facility.

Corporate and Other

Other Operation and Maintenance expense for Corporate and Other increased by $14 million primarily due to incremental merger-related transaction costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $16 million to $132 million in 2014 from $116 million in 2013 primarily due to:

- An increase of $5 million in amortization due to the expiration in August 2013 of the excess depreciation reserve regulatory liability of ACE.
- An increase of $4 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.
- An increase of $4 million due to utility plant additions.
- An increase of $4 million in amortization of regulatory assets primarily associated with the EmPower Maryland surcharge rate increase effective February 2014 (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $1 million in amortization of MAPP abandonment costs (which is offset in Regulated T&D Electric Revenue).

The aggregate amount of these increases was partially offset by a decrease of $1 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Fuel and Purchased Energy).

Deferred Electric Service Costs

Deferred Electric Service Costs, which relate only to ACE, represent (i) the over or under recovery of electricity costs incurred by ACE to fulfill its Default Electricity Supply obligation and (ii) the over or under recovery of New Jersey Societal Benefit Program costs incurred by ACE. The cost of electricity purchased is reported under Fuel and Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of the New Jersey Societal Benefit Program is reported under Other Operation and Maintenance and the corresponding revenue is reported under Regulated T&D Electric Revenue.

Deferred Electric Service Costs decreased by $9 million to an expense reduction of $13 million in 2014 as compared to an expense reduction of $4 million in 2013 primarily due to a decrease in deferred electricity expense as a result of lower wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from the NUGs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) decreased by $9 million to a net expense of $53 million in 2014 from a net expense of $62 million in 2013 primarily due to:

- An increase of $4 million in other income associated with a gain recorded in 2014 associated with the condemnation of certain Pepco transmission property.
- A decrease of $3 million in interest expense primarily associated with lower long-term interest expense and lower short-term debt.
- An increase of $1 million in income related to the allowance for funds used during construction (AFUDC) that is applied to capital projects.

Income Tax Expense

PHI's income tax expense increased by $15 million to $45 million in 2014 from $30 million in 2013. PHI's consolidated effective tax rates for the three months ended June 30, 2014 and 2013 were 45.9% and 36.1%, respectively. The increase in the effective tax rate resulted from the effect of certain incremental merger-related costs incurred in 2014 that are not tax deductible, partially offset by changes in estimates and interest related uncertain and effectively settled tax positions.

In connection with entering into the Merger Agreement (as further described in Note (1), "Organization"), PHI incurred certain incremental merger-related costs in the second quarter of 2014 which are not deductible for tax purposes and resulted in a higher effective tax rate in the three months ended June 30, 2014.

Discontinued Operations

PHI's loss from discontinued operations, net of income taxes, is comprised of the following:

	2014	2013	Change
Cross-border energy lease investments	$ —	$(15)	$ 15
Pepco Energy Services' retail electric and natural gas supply businesses	—	4	(4)
Loss from discontinued operations, net of income taxes	$ —	$(11)	$ 11

For the three months ended June 30, 2014 and 2013, loss from discontinued operations, net of income taxes, was zero and $11 million, respectively.

The decrease in loss from discontinued operations, net of income taxes, for PHI's cross-border energy lease investments of $15 million is primarily due to the loss of $14 million ($9 million after-tax) recorded in the three months ended June 30, 2013 for the early termination of PHI's interests in five of its six remaining cross-border energy lease investments, representing the excess of the carrying value of the terminated leases over the net cash proceeds received.

The decrease in income from discontinued operations, net of income taxes, at Pepco Energy Services of $4 million is due to the completion of the wind-down of the retail electric and natural gas supply businesses in 2013.

Consolidated Results of Operations

The following results of operations discussion compares the six months ended June 30, 2014 to the six months ended June 30, 2013. All amounts in the tables (except sales and customers) are in millions of dollars.

Continuing Operations

Operating Revenue

A detail of the components of PHI's consolidated operating revenue is as follows:

	2014	2013	Change
Power Delivery	$2,312	$2,130	$ 182
Pepco Energy Services	139	106	33
Corporate and Other	(4)	(5)	1
Total Operating Revenue	$2,447	$2,231	$ 216

Power Delivery

The following table categorizes Power Delivery's operating revenue by type of revenue.

	2014	2013	Change
Regulated T&D Electric Revenue	$1,086	$ 999	$ 87
Default Electricity Supply Revenue	1,070	984	86
Other Electric Revenue	31	33	(2)
Total Electric Operating Revenue	2,187	2,016	171
Regulated Gas Revenue	112	97	15
Other Gas Revenue	13	17	(4)
Total Gas Operating Revenue	125	114	11
Total Power Delivery Operating Revenue	$2,312	$2,130	$ 182

Regulated Transmission and Distribution (T&D) Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, by PHI's utility subsidiaries to customers within their service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that PHI's utility subsidiaries receive as transmission owners from PJM at rates regulated by FERC. Transmission rates are updated annually based on FERC-approved formula methodology.

Default Electricity Supply Revenue is the revenue received from the supply of electricity by PHI's utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive energy supplier. The costs related to Default Electricity Supply are included in Fuel and Purchased Energy. Default Electricity Supply Revenue also includes revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, and revenue in the form of transmission enhancement credits that PHI utility subsidiaries receive as transmission owners from PJM for approved regional transmission expansion plan costs.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated Gas Revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates.

Other Gas Revenue consists of DPL's off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Regulated T&D Electric

	2014	2013	Change
Regulated T&D Electric Revenue			
Residential	$ 389	$ 354	$ 35
Commercial and industrial	482	457	25
Transmission and other	215	188	27
Total Regulated T&D Electric Revenue	$ 1,086	$ 999	$ 87

	2014	2013	Change
Regulated T&D Electric Sales (GWh)			
Residential	8,672	8,282	390
Commercial and industrial	14,643	14,673	(30)
Transmission and other	124	122	2
Total Regulated T&D Electric Sales	23,439	23,077	362

	2014	2013	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,654	1,641	13
Commercial and industrial	199	199	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,855	1,842	13

Regulated T&D Electric Revenue increased by $87 million primarily due to:

- An increase of $47 million due to electric distribution base rate increases (Pepco in the District of Columbia effective March 2014, and in Maryland effective July 2013; DPL in Maryland effective September 2013, and in Delaware effective October 2013; ACE effective July 2013).
- An increase of $11 million in transmission revenue resulting from higher rates effective June 1, 2014 and June 1, 2013 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE complaint.
- An increase of $9 million due to Pepco and DPL customer growth in 2014, primarily in the residential class.
- An increase of $9 million due to an EmPower Maryland rate increase effective February 2014 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $8 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is substantially offset in Depreciation and Amortization).
- An increase of $5 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset in Purchased Energy and Depreciation and Amortization).
- An increase of $3 million due to higher sales primarily as a result of colder weather during the 2014 winter months, partially offset by milder weather during the spring months, as compared to 2013.
- An increase of $2 million in capacity revenue as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million primarily due to a rate decrease effective May 2013 associated with the Renewable Portfolio Surcharge in Delaware (which is substantially offset in Fuel and Purchased Energy and Depreciation and Amortization).
- A decrease of $4 million due to lower ACE non-weather related average commercial and residential customer usage.

Default Electricity Supply

	2014	2013	Change
Default Electricity Supply Revenue			
Residential	$ 659	$ 661	$ (2)
Commercial and industrial	273	253	20
Other	138	70	68
Total Default Electricity Supply Revenue	$ 1,070	$ 984	$ 86

	2014	2013	Change
Default Electricity Supply Sales (GWh)			
Residential	6,967	6,665	302
Commercial and industrial	2,562	2,479	83
Other	21	31	(10)
Total Default Electricity Supply Sales	9,550	9,175	375

	2014	2013	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,368	1,343	25
Commercial and industrial	126	126	—
Other	—	—	—
Total Default Electricity Supply Customers	1,494	1,469	25

Default Electricity Supply Revenue increased by $86 million primarily due to:

- An increase of $69 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.
- An increase of $23 million due to higher sales primarily as a result of colder weather during the 2014 winter months, as compared to 2013.
- An increase of $13 million due to higher sales, primarily as a result of customer migration from competitive suppliers.
- A net increase of $1 million due to higher DPL and Pepco non-weather related average customer usage, partially offset by lower usage at ACE.

The aggregate amount of these increases was partially offset by a net decrease of $19 million as a result of lower ACE and DPL Default Electricity Supply rates, partially offset by higher Pepco rates.

The variances described above with respect to Default Electricity Supply Revenue include the effects of a reduction of $8 million in ACE's BGS unbilled revenue resulting primarily from lower usage in the unbilled revenue period at June 30, 2014 as compared to the corresponding period at June 30 2013. Such a decrease in ACE's BGS unbilled revenue has the effect of directly decreasing the profitability of ACE's Default Electricity Supply business ($5 million decrease in net income) as these unbilled revenues are not included in the deferral calculation until they are billed to customers under the BGS terms approved by the NJBPU.

Regulated Gas

	2014	2013	Change
Regulated Gas Revenue			
Residential	$ 68	$ 62	$ 6
Commercial and industrial	38	29	9
Transportation and other	6	6	—
Total Regulated Gas Revenue	$ 112	$ 97	$ 15

	2014	2013	Change
Regulated Gas Sales (million cubic feet)			
Residential	5,710	4,959	751
Commercial and industrial	3,540	2,669	871
Transportation and other	3,662	3,886	(224)
Total Regulated Gas Sales	12,912	11,514	1,398

	2014	2013	Change
Regulated Gas Customers (in thousands)			
Residential	117	115	2
Commercial and industrial	9	10	(1)
Transportation and other	—	—	—
Total Regulated Gas Customers	126	125	1

Regulated Gas Revenue increased by $15 million primarily due to:

- An increase of $9 million due to higher sales primarily as a result of colder weather during the winter months of 2014 as compared to 2013.
- An increase of $7 million due to a distribution rate increase effective July 2013.
- An increase of $4 million due to higher non-weather related average customer usage.
- An increase of $2 million due to customer growth primarily in the residential customer classes.

The aggregate amount of these increases was partially offset by a decrease of $7 million due to a GCR decrease effective November 2013.

Other Gas Revenue

Other Gas Revenue decreased by $4 million primarily due to lower average prices and lower volumes for off-system sales to electric generators and gas marketers.

Pepco Energy Services

Pepco Energy Services' operating revenue increased by $33 million primarily due to:

- An increase of $27 million primarily in energy savings construction activities.
- An increase of $4 million associated with the thermal business in Atlantic City.
- An increase of $2 million in underground transmission and distribution construction activities.

Operating Expenses

Fuel and Purchased Energy and Other Services Cost of Sales

A detail of PHI's consolidated Fuel and Purchased Energy and Other Services Cost of Sales is as follows:

	2014	2013	Change
Power Delivery	$1,075	$1,009	$ 66
Pepco Energy Services	109	75	34
Corporate and Other	—	(1)	1
Total	$1,184	$1,083	$ 101

Power Delivery

Power Delivery's Fuel and Purchased Energy consists of the cost of electricity and natural gas purchased by its utility subsidiaries to fulfill their respective Default Electricity Supply and Regulated Gas obligations and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of natural gas purchased for off-system sales. Fuel and Purchased Energy expense increased by $66 million primarily due to:

- An increase of $20 million due to higher electricity sales primarily as a result of colder weather during the 2014 winter months, as compared to 2013.
- An increase of $19 million in deferred electricity expense primarily due to higher revenue associated with Pepco and DPL Default Electricity Supply sales, which resulted in a higher rate of recovery of Default Electricity Supply costs.
- An increase of $19 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $15 million primarily due to customer migration from competitive suppliers.
- A net increase of $11 million due to higher average electricity costs under Pepco Default Electricity Supply contracts, partially offset by lower DPL costs under Default Electricity Supply contracts and lower ACE costs under BGS contracts.

The aggregate amount of these increases was partially offset by:

- A decrease of $7 million in the cost of gas purchases for off-system sales as a result of lower volumes.
- A decrease of $6 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.
- A decrease of $4 million in deferred gas expense as a result of a lower rate of recovery of natural gas supply costs.

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales increased by $34 million primarily due to:

- An increase of $28 million primarily associated with increased energy savings construction activity.
- An increase of $2 million associated with the thermal business in Atlantic City.
- An increase of $4 million associated with increased underground transmission and distribution construction activities.

Other Operation and Maintenance

A detail of PHI's Other Operation and Maintenance expense is as follows:

	2014	2013	Change
Power Delivery	$429	$448	$ (19)
Pepco Energy Services	23	22	1
Corporate and Other	(15)	(31)	16
Total	$437	$439	$ (2)

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $19 million primarily due to:

- A decrease of $6 million associated with higher tree trimming costs in 2013.
- A decrease of $6 million in customer service and system support costs.
- A decrease of $3 million resulting from the 2013 write-off of disallowed MAPP and associated transmission project costs.
- A decrease of $3 million due to the deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. The deferral was recorded in accordance with a DCPSC rate order issued in March 2014 authorizing the establishment of regulatory asset for the recovery of these costs.
- A decrease of $2 million due to higher capitalized labor.
- A decrease of $1 million resulting from lower pension and other postretirement benefit expenses, partially offset by incremental merger-related integration costs.

The aggregate amount of these decreases was partially offset by an increase of $3 million in bad debt expense.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services increased by $1 million primarily associated with repairs and maintenance at its thermal business in Atlantic City and the demolition of the Benning Road generation facility.

Corporate and Other

Other Operation and Maintenance expense for Corporate and Other increased by $16 million primarily due to incremental merger-related transaction costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $37 million to $265 million in 2014 from $228 million in 2013 primarily due to:

- An increase of $10 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.
- An increase of $9 million in amortization due to the expiration in August 2013 of the excess depreciation reserve regulatory liability of ACE.
- An increase of $7 million in amortization of MAPP abandonment costs (which is offset in Regulated T&D Electric Revenue).
- An increase of $7 million due to utility plant additions.
- An increase of $5 million in amortization of regulatory assets primarily associated with the EmPower Maryland surcharge rate increase effective February 2014 (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

The aggregate amount of these increases was partially offset by a decrease of $2 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Fuel and Purchased Energy).

Deferred Electric Service Costs

Deferred Electric Service Costs, which relate only to ACE, represent (i) the over or under recovery of electricity costs incurred by ACE to fulfill its Default Electricity Supply obligation and (ii) the over or under recovery of New Jersey Societal Benefit Program costs incurred by ACE. The cost of electricity purchased is reported under Fuel and Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of the New Jersey Societal Benefit Program is reported under Other Operation and Maintenance and the corresponding revenue is reported under Regulated T&D Electric Revenue.

Deferred Electric Service Costs increased by $34 million to an expense of $31 million in 2014 as compared to an expense reduction of $3 million in 2013 primarily due to an increase in deferred electricity expense as a result of higher wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from the NUGs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) decreased by $16 million to a net expense of $105 million in 2014 from a net expense of $121 million in 2013 primarily due to:

- An increase of $8 million in other income associated with gains recorded in 2014 associated with the condemnation of certain Pepco transmission property.
- A decrease of $5 million in interest expense primarily associated with lower short-term debt and lower long-term debt interest expense.
- An increase of $2 million in income related to AFUDC that is applied to capital projects.

Income Tax Expense

PHI's income tax expense decreased by $124 million to $91 million in 2014 from $215 million in 2013. PHI's consolidated effective tax rates for the six months ended June 30, 2014 and 2013 were 41.6% and 136.9%, respectively. The decrease in the effective tax rate was as a result of changes in estimates and interest related uncertain and effectively settled tax positions and deferred tax valuation allowances established in the first quarter of 2013, partially offset by the effect of certain incremental merger-related costs incurred in 2014 that are not tax deductible.

In connection with entering into the Merger Agreement (as further described in Note (1), "Organization"), PHI incurred certain incremental merger-related costs in the second quarter of 2014 which are not deductible for tax purposes and resulted in a higher effective tax rate in the six months ended June 30, 2014.

In the first quarter of 2013, PHI recorded interest expense related to uncertain and effectively settled tax positions of $51 million primarily representing the anticipated additional interest expense on estimated federal and state income tax obligations that was allocated to PHI's continuing operations resulting from a change in assessment of tax benefits associated with the former cross-border energy lease investments of PCI in the first quarter of 2013.

Also, in the first quarter of 2013, PHI established valuation allowances of $101 million related to deferred tax assets. Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to other taxpayers' cross-border lease and other structured transactions (as discussed in Note (18), "Discontinued Operations – Cross-Border Energy Lease Investments"), (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI would be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of all relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances.

Discontinued Operations

PHI's loss from discontinued operations, net of income taxes, is comprised of the following:

	2014	2013	Change
Cross-border energy lease investments	$—	$(334)	$ 334
Pepco Energy Services' retail electric and natural gas supply businesses	—	4	(4)
Loss from discontinued operations, net of income taxes	$—	$(330)	$ 330

For the six months ended June 30, 2014 and 2013, loss from discontinued operations, net of income taxes, was zero and $330 million, respectively.

The decrease in loss from discontinued operations, net of income taxes, for PHI's cross-border energy lease investments of $334 million is primarily related to a change in assessment regarding the tax benefits related to the cross-border energy lease investments consisting of a $373 million non-cash pre-tax charge ($313 million after-tax) to reduce the carrying value of the investments and a $16 million non-cash after-tax charge to reflect the anticipated additional interest expense related to the change in PCI's estimated federal and state income tax obligations as if it were a separate taxpayer. In addition, PHI recorded a loss of $14 million ($9 million after-tax) in the three months ended June 30, 2013 for the early termination of PHI's interests in five of its six remaining cross-border energy lease investments, representing the excess of the carrying value of the terminated leases over the net cash proceeds received.

The decrease in income from discontinued operations, net of income taxes, at Pepco Energy Services of $4 million is due to the completion of the wind-down of the retail electric and natural gas supply businesses in 2013.

Capital Resources and Liquidity

This section discusses PHI's working capital, cash flow activity, capital requirements and other uses and sources of capital.

Working Capital

At June 30, 2014, PHI's current assets on a consolidated basis totaled $1.3 billion and its consolidated current liabilities totaled $1.8 billion, resulting in a working capital deficit of $451 million. PHI expects the working capital deficit at June 30, 2014 to be funded during 2014 in part through cash flows from operations and from the issuance of long-term debt. At December 31, 2013, PHI's current assets on a consolidated basis totaled $1.4 billion and its consolidated current liabilities totaled $2.3 billion, for a working capital deficit of $915 million. The decrease of $464 million in the working capital deficit from December 31, 2013 to June 30, 2014 was primarily due to an increase in cash, lower short-term debt and lower net current income tax liabilities associated with the implementation of a new accounting standard, which required certain non-current deferred income tax assets to be netted against current income tax liabilities.

At June 30, 2014, PHI's consolidated cash and cash equivalents totaled $184 million, which consisted of cash and uncollected funds but excluded current Restricted Cash Equivalents (cash that is available to be used only for designated purposes) that totaled $21 million. At December 31, 2013, PHI's consolidated cash and cash equivalents totaled $23 million, which consisted of cash and uncollected funds but excluded current Restricted Cash Equivalents that totaled $13 million.

Detail of PHI's short-term debt balance and current maturities of long-term debt and project funding balance is as follows:

	As of June 30, 2014 (millions of dollars)							
Type	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PCI	PHI Consolidated
Variable Rate Demand Bonds	$ —	$—	$105	$—	$ —	$ —	$—	$ 105
Commercial Paper	194	—	—	180	—	—	—	374
Total Short-Term Debt	$ 194	$—	$105	$180	$ —	$ —	$—	$ 479
Current Portion of Long-Term Debt and Project Funding	$ —	$ 5	$200	$107	$ 42	$ 17	$—	$ 371

Type	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PCI	PHI Consolidated
	As of December 31, 2013 (millions of dollars)							
Variable Rate Demand Bonds	$ —	$—	$105	$ 18	$ —	$ —	$—	$ 123
Commercial Paper	24	151	147	120	—	—	—	442
Total Short-Term Debt	$ 24	$151	$252	$138	$ —	$ —	$—	$ 565
Current Portion of Long-Term Debt and Project Funding	$ —	$175	$100	$107	$ 41	$ 12	$ 11	$ 446

Commercial Paper

PHI, Pepco, DPL and ACE maintain commercial paper programs to address short-term liquidity needs. As of June 30, 2014, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $350 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, Pepco, DPL and ACE had $194 million, zero, zero and $180 million, respectively, of commercial paper outstanding at June 30, 2014. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2014 was 0.52%, 0.27%, 0.26% and 0.25%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2014 was three, six, five and four days, respectively.

Financing Activity During the Three Months Ended June 30, 2014

Bond Issuance

In June 2014, DPL issued $200 million of its 3.50% first mortgage bonds due November 15, 2023. Net proceeds from the issuance of the bonds, which included a premium of $4 million, were used to repay DPL's outstanding commercial paper and for general corporate purposes.

Bond Payments

In April 2014, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

Bond Retirements

In April 2014, Pepco retired, at maturity, $175 million of its 4.65% senior notes. The senior notes were secured by a like principal amount of its 4.65% first mortgage bonds due April 15, 2014, which under Pepco's mortgage and deed of trust were deemed to be satisfied when the senior notes were repaid.

In April 2014, ACE retired, at maturity, $18 million tax-exempt unsecured variable rate demand bonds issued for the benefit of ACE by the Pollution Control Financing Authority of Salem County.

In April 2014, PCI repaid, at maturity, $11 million of bank loans.

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility is currently August 1, 2018.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion, and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 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 sublimit reallocations may not exceed eight per year during the term of the facility.

For additional discussion of the Credit Facility, see Note (9), “Debt,” to the consolidated financial statements of PHI.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of “Change in Control” in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings.

ACE Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the London Interbank Offered Rate (LIBOR) with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE’s Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of June 30, 2014, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.91%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of June 30, 2014.

Cash and Credit Facility Available as of June 30, 2014

	Consolidated PHI	PHI Parent	Utility Subsidiaries
		(millions of dollars)	
Credit Facility (Total Capacity)	$ 1,500	$ 750	$ 750
Less: Letters of Credit issued	2	2	—
Commercial Paper outstanding	374	194	180
Remaining Credit Facility Available	1,124	554	570
Cash Invested in Money Market Funds and on hand (a)	166	—	166
Total Cash and Credit Facility Available	$ 1,290	$ 554	$ 736

(a) Cash and Cash Equivalents reported on the PHI consolidated balance sheet totaled $184 million, of which $166 million was invested in money market funds, and the balance was held in cash and uncollected funds.

Financing Activities Subsequent to June 30, 2014

Bond Payments

In July 2014, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

PHI's Cross-Border Energy Lease Investments

PHI has an ongoing dispute with the IRS regarding the appropriateness of certain significant income tax benefits claimed by PHI related to its cross-border energy lease investments beginning with its 2001 federal income tax return. In the first quarter of 2013, PHI estimated that, in the event the IRS were to be fully successful in its challenge to PHI's tax position on the cross-border energy leases, PHI would have been obligated to pay $192 million in additional federal taxes and $50 million of interest on the additional federal taxes, totaling $242 million as of March 31, 2013. The estimate of additional federal taxes due includes PHI's estimate of the expected resolution of other uncertain and effectively settled tax positions unrelated to the leases, the carrying back or carrying forward of any existing net operating losses, and the application of certain amounts paid in advance to the IRS.

In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made a $242 million advanced payment to the IRS for the estimated additional taxes and related interest in the first quarter of 2013. This advanced payment was funded from then currently available sources of liquidity and short-term borrowings. In March 2013, PHI began to pursue the early termination of its six remaining cross-border energy lease investments, which had a net carrying value of approximately $869 million as of March 31, 2013. During the second and third quarters of 2013, PHI terminated early all of its interests in the six remaining lease investments. PHI received aggregate net cash proceeds of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. A portion of the net cash proceeds from the terminated leases was used to repay borrowings utilized to fund the advanced payment discussed above.

Pension and Postretirement Benefit Plans

PHI sponsors a non-contributory, defined benefit pension plan (the PHI Retirement Plan) that covers substantially all employees of Pepco, DPL and ACE and certain employees of other PHI subsidiaries. PHI also provides supplemental retirement benefits to certain eligible executive and key employees through nonqualified retirement plans. PHI's funding policy with regard to the PHI Retirement Plan is to maintain a funding level that is at least equal to the target liability as defined under the Pension Protection Act of 2006.

Under the Pension Protection Act, if a plan incurs a funding shortfall in the preceding plan year, there can be required minimum quarterly contributions in the current and following plan years. In 2014, PHI, Pepco, DPL and ACE do not expect to make discretionary tax-deductible contributions to the PHI Retirement Plan. Management expects that the current balance of the PHI Retirement Plan assets is at least equal to the funding target liability for 2014 under the Pension Protection Act. During 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan of $80 million, $10 million and $30 million, respectively. PHI satisfied the minimum required contribution rules under the Pension Protection Act in 2013. For additional discussion of PHI's Pension and Other Postretirement Benefits, see Note (8), "Pension and Other Postretirement Benefits," to the consolidated financial statements of PHI.

PHI provides certain postretirement health care and life insurance benefits for eligible retired employees. Most employees hired after January 1, 2005 or later will not have company subsidized retiree health care coverage; however, they will be able to purchase coverage at full cost through PHI.

Based on the results of the 2013 actuarial valuation, PHI's net periodic pension and OPEB costs were approximately $94 million in 2013. The current estimate of net periodic pension and other postretirement benefit cost for 2014 is $56 million. The utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and OPEB costs. Approximately 37% of net periodic pension and OPEB costs were capitalized in 2013. PHI anticipates approximately 37% of its annual net periodic pension and OPEB costs will be capitalized in 2014.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and retiree life insurance benefits, and became effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation as of July 1, 2013. The remeasurement resulted in a $16 million reduction in net periodic benefit cost for other postretirement benefits during the six months ended June 30, 2014, when compared to the six months ended June 30, 2013.

Cash Flow Activity

PHI's cash flows for the six months ended June 30, 2014 and 2013 are summarized below:

	Cash Source (Use)		
	2014	**2013**	**Change**
	(millions of dollars)		
Operating Activities	$ 419	$(47)	$ 466
Investing Activities	(546)	83	(629)
Financing Activities	288	(46)	334
Net increase (decrease) in cash and cash equivalents	$ 161	$(10)	$ 171

Operating Activities

Cash flows from operating activities during the six months ended June 30, 2014 and 2013 are summarized below:

	Cash Source (Use)		
	2014	2013	Change
		(millions of dollars)	
Net income (loss) from continuing operations	$128	$ (58)	$ 186
Non-cash adjustments to net income	250	223	27
Pension contributions	—	(120)	120
Advanced payment made to taxing authority	—	(242)	242
Changes in cash collateral related to derivative activities	(5)	26	(31)
Changes in other assets and liabilities	46	72	(26)
Changes in net current assets held for disposition or sale	—	52	(52)
Net cash from (used by) operating activities	$419	$ (47)	$ 466

Net cash from operating activities increased $466 million for the six months ended June 30, 2014, compared to the same period in 2013. The increase was primarily due to an increase in net income of $186 million, a decrease in pension contributions of $120 million and a $242 million advanced payment to the IRS for estimated additional taxes and related interest made in 2013, partially offset by a $52 million reduction in net current assets held for disposition or sale associated with the early termination of all cross-border energy lease investments and the wind-down of Pepco Energy Services' retail electric and natural gas supply businesses.

Investing Activities

Cash flows used by investing activities during the six months ended June 30, 2014 and 2013 are summarized below:

	Cash (Use) Source		
	2014	2013	Change
		(millions of dollars)	
Investment in property, plant and equipment	$(553)	$(616)	$ 63
Department of Energy (DOE) capital reimbursement awards received	4	12	(8)
Proceeds from sale of land	8	—	8
Changes in restricted cash equivalents	(8)	(8)	—
Net other investing activities	3	2	1
Proceeds from discontinued operations, early termination of finance leases held in trust	—	693	(693)
Net cash (used by) from investing activities	$(546)	$ 83	$ (629)

Net cash used by investing activities increased $629 million for the six months ended June 30, 2014, compared to the same period in 2013. The increase was primarily due to $693 million of proceeds from discontinued operations related to the early termination of all cross-border energy lease investments received in 2013, partially offset by a $63 million decrease in investments in property, plant and equipment.

Financing Activities

Cash flows from financing activities during the six months ended June 30, 2014 and 2013 are summarized below:

	Cash (Use) Source		
	2014	2013	Change
	(millions of dollars)		
Dividends paid on common stock	$(136)	$(134)	$ (2)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan (DRP) and employee-related compensation (a)	26	27	(1)
Issuances of common stock	—	324	(324)
Issuance of Series A preferred stock	90	—	90
Issuances of long-term debt	608	350	258
Reacquisitions of long-term debt	(206)	(19)	(187)
Repayments of short-term debt, net	(86)	(373)	287
Issuance of term loan	—	250	(250)
Repayment of term loans	—	(450)	450
Cost of issuances	(8)	(16)	8
Net other financing activities	—	(5)	5
Net cash from (used by) financing activities	$ 288	$ (46)	$ 334

(a) Prior to October 1, 2013, the DRP was named the Shareholder Dividend Reinvestment Plan.

Net cash from financing activities increased $334 million for the six months ended June 30, 2014, compared to the same period in 2013. The increase was primarily due to an increase of $258 million in issuances of long-term debt, a decrease of $200 million in net repayments of term loans, a decrease of $287 million of short-term debt repayments, and an issuance of preferred stock of $90 million, partially offset by issuances of common stock of $324 million in 2013 primarily due to the settlement of the equity forward transaction.

Changes in Outstanding Long-Term Debt

Cash flows from the issuances and reacquisitions of long-term debt for the six months ended June 30, 2014 and 2013 are summarized below:

	Issuances	
	2014	2013
	(millions of dollars)	
Pepco		
3.60% First mortgage bonds due 2024	$ 400	$ —
4.15% First mortgage bonds due 2043	—	250
Project Funding Debt	4	—
	404	250
DPL		
3.50% First mortgage bonds due 2023	204	—
	204	—
ACE		
Term loan due 2014	—	100
	—	100
	$ 608	$ 350

	Reacquisitions 2014	Reacquisitions 2013
	(millions of dollars)	
Pepco		
4.65% First mortgage bonds due 2014	$ 175	$ —
	175	—
ACE		
Securitization bonds due 2013-2014	20	19
	20	19
PCI		
6.59% - 6.69% Recourse Debt	11	—
	11	—
	$ 206	$ 19

Changes in Short-Term Debt

As of June 30, 2014, PHI had a total of $374 million of commercial paper outstanding as compared to $442 million of commercial paper outstanding as of December 31, 2013.

On March 28, 2013, PHI entered into a $250 million term loan agreement, pursuant to which PHI had borrowed (and was not permitted to re-borrow) $250 million. PHI used the net proceeds of the loan under the loan agreement to repay the outstanding $200 million term loan obtained in 2012, and for general corporate purposes. On May 29, 2013, PHI repaid the $250 million term loan with a portion of the net proceeds from the early termination of the cross-border energy lease investments.

Capital Requirements

Capital Expenditures

Pepco Holdings' capital expenditures for the six months ended June 30, 2014 were $553 million, of which $241 million was incurred by Pepco, $172 million was incurred by DPL, $104 million was incurred by ACE, $1 million was incurred by Pepco Energy Services and $35 million was incurred by Corporate and Other. The Power Delivery expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. Corporate and Other capital expenditures primarily consisted of hardware and software expenditures that will be allocated to Power Delivery when the assets are placed in service.

In its 2013 Form 10-K, PHI presented its projected capital expenditures for the five-year period 2014 through 2018, which reflected aggregate expenditures of $5,872 million. Projected capital expenditures include expenditures for distribution, transmission and gas delivery which primarily relate to facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts. These projected capital expenditures also include expenditures for the smart grid programs undertaken by each of PHI's utility subsidiaries to install smart meters, further automate their electric distribution systems and enhance their communications infrastructure. During the first and second quarters of 2014, PHI added to its projected capital expenditures for Power Delivery certain additional transmission projects at Pepco and ACE and the District of Columbia Power Line Undergrounding initiative at Pepco with aggregate projected capital expenditures of approximately $433 million over the five-year period 2014 through 2018, which will result in additional expenditures of $27 million in 2014, $96 million in 2015, $121 million in 2016, $113 million in 2017 and $76 million in 2018.

DOE Capital Reimbursement Awards

In 2009, the DOE announced awards under the American Recovery and Reinvestment Act of 2009 of:

- $105 million and $44 million in Pepco's Maryland and District of Columbia service territories, respectively, for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure.
- $19 million in ACE's New Jersey service territory for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure.

During 2010, Pepco, ACE and the DOE signed agreements formalizing the $168 million in awards. Of the $168 million, $130 million is being used for the smart grid and other capital expenditures of Pepco and ACE. The remaining $38 million is being used to offset incremental expenditures associated with direct load control and other Pepco and ACE programs. For the six months ended June 30, 2014, Pepco and ACE received award payments of $3 million and $1 million, respectively. Cumulative award payments received by Pepco and ACE as of June 30, 2014, were $148 million and $19 million, respectively.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

Guarantees, Indemnifications, Obligations and Off-Balance Sheet Arrangements

PHI and certain of its subsidiaries have various financial and performance guarantees and indemnification obligations that they have entered into in the normal course of business to facilitate commercial transactions with third parties.

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At June 30, 2014, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $255 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects. These guarantees totaled $218 million at June 30, 2014.

In addition, PHI guarantees certain obligations of Pepco, DPL and ACE under surety bonds obtained by these subsidiaries, for construction projects and self-insured workers compensation matters. These guarantees totaled $53 million at June 30, 2014.

For additional discussion of PHI's third party guarantees, indemnifications, obligations and off-balance sheet arrangements, see Note (15), "Commitments and Contingencies – Third Party Guarantees, Indemnifications, and Off-Balance Sheet Arrangements," to the consolidated financial statements of PHI.

Dividends

On July 24, 2014, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable September 30, 2014 to stockholders of record on September 10, 2014. PHI had approximately $587 million and $595 million of retained earnings free of restrictions at June 30, 2014 and December 31, 2013, respectively.

Contractual Arrangements with Credit Rating Triggers or Margining Rights

Under certain contractual arrangements entered into by PHI's subsidiaries, the subsidiary may be required to provide cash collateral or letters of credit as security for its contractual obligations if the credit ratings of PHI or the subsidiary are downgraded. In the event of a downgrade, the amount required to be posted would depend on the amount of the underlying contractual obligation existing at the time of the downgrade. Based on contractual provisions in effect at June 30, 2014, a downgrade in the unsecured debt credit ratings of PHI and each of its rated subsidiaries to below "investment grade" would increase the collateral obligation of PHI and its subsidiaries by up to $45 million. This amount is attributable primarily to energy services contracts and accounts payable to independent system operators and distribution companies. PHI believes that it and its subsidiaries currently have sufficient liquidity to fund their operations and meet their financial obligations.

Many of the contractual arrangements entered into by PHI's subsidiaries in connection with Default Electricity Supply activities include margining rights pursuant to which the PHI subsidiary or a counterparty may request collateral if the market value of the contractual obligations reaches levels in excess of the credit thresholds established in the applicable arrangements. Pursuant to these margining rights, the affected PHI subsidiary may receive, or be required to post, collateral due to energy price movements. PHI believes that it and its subsidiaries currently have sufficient liquidity to fund their operations and meet their financial obligations.

Regulatory and Other Matters

Rate Proceedings

Distribution

The rates that each of Pepco, DPL and ACE is permitted to charge for the retail distribution of electricity and natural gas to its various classes of customers are based on the principle that the utility is entitled to generate an amount of revenue sufficient to recover the cost of providing the service, including a reasonable rate of return on its invested capital. These "base rates" are intended to cover all of each utility's reasonable and prudent expenses of constructing, operating and maintaining its distribution facilities (other than costs covered by specific cost-recovery surcharges).

A change in base rates in a jurisdiction requires the approval of the public service commission. In the rate application submitted to the public service commission, the utility specifies an increase in its "revenue requirement," which is the additional revenue that the utility is seeking authorization to earn. The "revenue requirement" consists of (i) the allowable expenses incurred by the utility, including operation and maintenance expenses, taxes and depreciation, and (ii) the utility's cost of capital. The compensation of the utility for its cost of capital takes the form of an overall "rate of return" allowed by the public service commission on the utility's distribution "rate base" to compensate the utility's investors for their debt and equity investments in the company. The rate base is the aggregate value of the investment in property used by the utility in providing electricity and natural gas distribution services and generally consists of plant in service net of accumulated depreciation and accumulated deferred taxes, plus cash working capital, material and operating supplies and, depending on the jurisdiction, construction work in progress. Over time, the rate base is increased by utility property additions and reduced by depreciation and property retirements and write-offs.

In addition to its base rates, some of the costs of providing distribution service are recovered through the operation of surcharges. Examples of costs recovered by PHI's utility subsidiaries through surcharges, which vary depending on the jurisdiction, include: a surcharge to reimburse the utility for the cost of purchasing electricity from NUGs (New Jersey); surcharges to reimburse the utility for costs of public interest programs for low income customers and for demand-side management programs (New Jersey, Maryland, Delaware and the District of Columbia); a surcharge to pay the Transitional Bond Charge (New Jersey); surcharges to reimburse the utility for certain environmental costs (Delaware and Maryland); and surcharges related to the BSA (Maryland and the District of Columbia). Each utility subsidiary regularly reviews its distribution rates in each jurisdiction of its service territory, and files applications to adjust its rates as necessary in an effort to ensure that its revenues are sufficient to cover its operating expenses and its cost of capital. The timing of future rate filings and the change in the distribution rate requested will depend on a number of factors, including changes in revenues and expenses and the incurrence or the planned incurrence of capital expenditures.

As further described in "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger," PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings. In addition, the regulatory commissions may seek to suspend or delay one or more of the ongoing proceedings as a result of the Merger Agreement. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

In general, a request for new distribution rates is made on the basis of "test year" balances for rate base allowable operating expenses and a requested rate of return. The test year amounts used in the filing may be historical or partially projected. The public service commission may, however, select a different test period than that proposed by the applicable utility. Although the approved tariff rates are intended to be forward-looking, and therefore provide for the recovery of some future changes in rate base and operating costs, they typically do not reflect all of the changes in costs for the period in which the new rates are in effect.

The following table shows, for each of the PHI utility subsidiaries, the authorized return on equity as determined in the most recently concluded base rate proceeding and the effective date of the authorized return:

	Authorized Return on Equity	Rate Effective Date
Pepco:		
District of Columbia (electricity)	9.40%	April 2014
Maryland (electricity)	9.62%	July 2014
DPL:		
Delaware (electricity)	9.70%	May 2014 (a)
Maryland (electricity)	9.81% (b)	September 2013
Delaware (natural gas)	9.75% (c)	November 2013
ACE:		
New Jersey (electricity)	9.75%	July 2013

(a) Beginning in September 2014, DPL will provide credits or refunds to any customer whose rates were increased in October 2013, in an amount that exceeded the increase approved by the DPSC in April 2014.
(b) ROE has not been determined by any proceeding and is specified only for the purposes of calculating the AFUDC and regulatory asset carrying costs.
(c) ROE has not been determined by any proceeding and is specified only for reporting purposes and for calculating the AFUDC, construction work in progress, regulatory asset carrying costs and other accounting metrics.

Transmission

The rates Pepco, DPL and ACE are permitted to charge for the transmission of electricity are regulated by FERC and are based on each utility's transmission rate base, transmission operating expenses and an overall rate of return that is approved by FERC. For each utility subsidiary, FERC has approved a formula for the calculation of the utility transmission rate, which is referred to as a "formula rate." The formula rates include both fixed and variable elements. Certain of the fixed elements, such as the return on equity and depreciation rates, can be changed only in a FERC transmission rate proceeding. The variable elements of the formula, including the utility's rate base and operating expenses, are updated annually, effective June 1 of each year, with data from the utility's most recent annual FERC Form 1 filing. See Note (7), "Regulatory Matters – Rate Proceedings – Federal Energy Regulatory Commission" to the consolidated financial statements of PHI, regarding certain challenges to DPL's 2011, 2012 and 2013 annual formula rate updates.

In addition to its formula rate, each utility's return on equity is supplemented by incentive rates, sometimes referred to as "adders," and other incentives, which are authorized by FERC to promote capital investment in transmission infrastructure. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for PHI's utilities for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. In addition, ROE adders are in effect for each of Pepco, DPL and ACE relating to specific transmission upgrades and improvements, as well as in consideration for each utility's continued membership in PJM. As members of PJM, the transmission rates of Pepco, DPL and ACE are set out in PJM's Open Access Transmission Tariff.

For a discussion of pending state public utility commission and FERC transmission rate and other regulatory proceedings, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Legal Proceedings and Regulatory Matters

For a discussion of legal proceedings, see Note (15), "Commitments and Contingencies," to the consolidated financial statements of PHI, and for a discussion of regulatory matters, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Critical Accounting Policies

For a discussion of Pepco Holdings' critical accounting policies, please refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Pepco Holdings' 2013 Form 10-K. There have been no material changes to PHI's critical accounting policies as disclosed in the 2013 Form 10-K.

New Accounting Standards and Pronouncements

For information concerning new accounting standards and pronouncements that have recently been adopted by PHI and its subsidiaries or that one or more of the companies will be required to adopt on or before a specified date in the future, see Note (3), "Newly Adopted Accounting Standards," and Note (4), "Recently Issued Accounting Standards, Not Yet Adopted," to the consolidated financial statements of PHI.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Potomac Electric Power Company

Pepco meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

Pepco is engaged in the transmission and distribution of electricity in the District of Columbia and major portions of Prince George's County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply. Pepco's service territory covers approximately 640 square miles and, as of June 30, 2014, had a population of approximately 2.2 million. As of June 30, 2014, approximately 57% of delivered electricity sales were to Maryland customers and approximately 43% were to District of Columbia customers.

Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenue is not affected by unseasonably warmer or colder weather because a BSA for retail customers was implemented that provides for a fixed distribution charge per customer rather than a charge based on energy usage. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland and District of Columbia retail distribution sales falls short of the revenue that Pepco is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco is entitled to earn based on the approved distribution charge per customer.

Pepco is a wholly owned subsidiary of PHI. Because PHI is a public utility holding company subject to the Public Utility Holding Company Act of 2005 (PUHCA 2005), the relationship between each of PHI, PHI Service Company (a subsidiary service company of PHI, which provides a variety of support services, including legal, accounting, treasury, tax, purchasing and information technology services to PHI and its operating subsidiaries) and Pepco, as well as certain activities of Pepco, are subject to FERC's regulatory oversight under PUHCA 2005.

Agreement and Plan of Merger

PHI has entered into the Merger Agreement with Exelon and Merger Sub. For additional information regarding the Merger, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger."

Utility Capital Expenditures

Pepco devotes a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territories. These activities include one or more of the following:

- identifying and upgrading under-performing feeder lines;
- adding new facilities to support load;
- installing distribution automation systems on both the overhead and underground network systems; and
- rejuvenating and replacing underground residential cables.

Smart Grid

Pepco is building a "smart grid" which is designed to meet the challenges of rising energy costs, improve service reliability of the energy distribution system, provide timely and accurate customer information and address government energy reduction goals. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid Initiatives."

Mitigation of Regulatory Lag

An important factor in the ability of Pepco to earn its authorized ROE is the willingness of the DCPSC and the MPSC to adequately address the shortfall in revenues in Pepco's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." Pepco is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

MAPP Settlement Agreement

In February 2014, FERC issued an order approving the settlement agreement submitted by Pepco in connection with its' proceeding seeking recovery of approximately $50 million in abandonment costs related to the MAPP project. Pepco had been directed by PJM to construct the MAPP project, a 152-mile high-voltage interstate transmission line, and was subsequently directed by PJM to cancel it. The abandonment costs sought for recovery were subsequently reduced to $45 million from write-offs of certain disallowed costs in 2013 and transfers of materials to inventories for use on other projects. Under the terms of the FERC-approved settlement agreement, Pepco will receive approximately $43.9 million of transmission revenues over a three-year period, which began on June 1, 2013, and will retain title to all real property and property rights acquired in connection with the MAPP project, which had an estimated fair value of $2 million. The FERC-approved settlement agreement resolves all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project, and the terms of the settlement agreement are not subject to modification through any other FERC proceeding. As of June 30, 2014, Pepco had a regulatory asset related to the MAPP abandonment costs of approximately $27 million, net of amortization, and land of $2 million. Pepco does not expect to recognize any further pre-tax income related to the MAPP abandonment costs.

Transmission ROE Challenge

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, among others. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that Pepco provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for Pepco is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. Pepco believes the allegations in this complaint are without merit and is vigorously contesting it. In April 2013, Pepco filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. Pepco cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, PHI is permitted, and intends to continue, to pursue the conclusion of this matter.

On June 19, 2014, FERC issued an order in a proceeding in which Pepco was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint filed against Pepco and its utility affiliates, Pepco believes that it is probable that FERC will direct Pepco to use this methodology at the time it issues an order addressing the complaint. As a result, Pepco applied an estimated ROE based on the two-step methodology announced by FERC for the period over which Pepco's transmission revenues would be subject to refund as a result of the challenge, and has recorded an estimated reserve in the second quarter of 2014 related to this matter.

Earnings Overview

Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

Pepco's net income for the six months ended June 30, 2014 was $78 million compared to $60 million for the six months ended June 30, 2013. The $18 million increase in earnings was primarily due to the following:

- An increase of $10 million from electric distribution base rate increases in the District of Columbia and in Maryland.
- An increase of $7 million due to lower operation and maintenance expense primarily associated with higher tree trimming costs in 2013, a decrease resulting from the allowed recovery in 2014 of certain previously expensed rate case costs in accordance with a District of Columbia rate order and higher capitalized labor.
- An increase of $5 million in other income related to gains recorded in 2014 associated with the condemnation of certain transmission property.
- An increase of $4 million due to customer growth.
- A decrease of $4 million due to higher depreciation and amortization expense associated with regulatory assets and increases in plant investment.
- A decrease of $4 million due to lower tax benefits related to uncertain and effectively settled tax positions.

Results of Operations

The following results of operations discussion compares the six months ended June 30, 2014 to the six months ended June 30, 2013. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of Pepco's statement of income for the six months ended June 30, 2014 compared to the six months ended June 30, 2013, is set forth in the table below:

	2014	2013	Change
Operating revenue	$1,043	$946	$ 97
Purchased energy	407	349	58
Other operation and maintenance	184	197	(13)
Depreciation and amortization	112	96	16
Other taxes	180	177	3
Total operating expenses	883	819	64
Operating income	160	127	33
Other income (expenses)	(38)	(45)	7
Income before income tax expense	122	82	40
Income tax expense	44	22	22
Net income	$ 78	$ 60	$ 18

Operating Revenue

	2014	2013	Change
Regulated T&D Electric Revenue	$ 605	$566	$ 39
Default Electricity Supply Revenue	422	362	60
Other Electric Revenue	16	18	(2)
Total Operating Revenue	$1,043	$946	$ 97

The table above shows the amount of Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to Pepco's customers within its service territory at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2014	2013	Change
Regulated T&D Electric Revenue			
Residential	$ 178	$ 163	$ 15
Commercial and industrial	334	319	15
Transmission and other	93	84	9
Total Regulated T&D Electric Revenue	$ 605	$ 566	$ 39

	2014	2013	Change
Regulated T&D Electric Sales (GWh)			
Residential	4,058	3,806	252
Commercial and industrial	8,719	8,630	89
Transmission and other	78	75	3
Total Regulated T&D Electric Sales	12,855	12,511	344

	2014	2013	Change
Regulated T&D Electric Customers (in thousands)			
Residential	728	719	9
Commercial and industrial	74	74	—
Transmission and other	—	—	—
Total Regulated T&D Electric Customers	802	793	9

Regulated T&D Electric Revenue increased by $39 million primarily due to:

- An increase of $17 million due to electric distribution base rate increases in the District of Columbia effective March 2014 and in Maryland effective July 2013.
- An increase of $7 million due to customer growth in 2014, primarily in the residential class.
- An increase of $7 million due to an EmPower Maryland rate increase effective February 2014 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $4 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $2 million in transmission revenue resulting from higher rates effective June 1, 2014 and June 1, 2013 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE complaint.
- An increase of $2 million in capacity revenue as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).

Default Electricity Supply

	2014	2013	Change
Default Electricity Supply Revenue			
Residential	$ 287	$ 252	$ 35
Commercial and industrial	127	101	26
Other	8	9	(1)
Total Default Electricity Supply Revenue	$ 422	$ 362	$ 60

	2014	2013	Change
Default Electricity Supply Sales (GWh)			
Residential	3,096	2,899	197
Commercial and industrial	1,406	1,322	84
Other	3	11	(8)
Total Default Electricity Supply Sales	4,505	4,232	273

	2014	2013	Change
Default Electricity Supply Customers (in thousands)			
Residential	572	558	14
Commercial and industrial	44	43	1
Other	—	—	—
Total Default Electricity Supply Customers	616	601	15

Default Electricity Supply Revenue increased by $60 million primarily due to:

- An increase of $39 million as a result of higher Default Electricity Supply rates.
- An increase of $12 million due to higher sales, primarily as a result of colder weather during the 2014 winter months, as compared to 2013.
- An increase of $9 million due to higher sales, primarily as a result of customer migration from competitive suppliers.

The following table shows the percentages of Pepco's total distribution sales by jurisdiction that are derived from customers receiving Default Electricity Supply from Pepco. Amounts are for the six months ended June 30:

	2014	2013
Sales to District of Columbia customers	27%	25%
Sales to Maryland customers	41%	40%

<u>*Operating Expenses*</u>

Purchased Energy

Purchased Energy consists of the cost of electricity purchased by Pepco to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy increased by $58 million to $407 million in 2014 from $349 million in 2013 primarily due to:

- An increase of $24 million due to higher average electricity costs under Default Electricity Supply contracts.
- An increase of $15 million in deferred electricity expense primarily due to higher revenue associated with Default Electricity Supply sales, which resulted in a higher rate of recovery of Default Electricity Supply costs.
- An increase of $10 million due to higher electricity sales primarily as a result of colder weather during the 2014 winter months, as compared to 2013.
- An increase of $10 million primarily due to customer migration from competitive suppliers.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $13 million to $184 million in 2014 from $197 million in 2013 primarily due to:

- A decrease of $4 million associated with higher tree trimming costs in 2013.
- A decrease of $4 million due to higher capitalized labor.
- A decrease of $3 million due to the deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. The deferral was recorded in accordance with a DCPSC rate order issued in March 2014 authorizing the establishment of a regulatory asset for the recovery of these costs.
- A decrease of $1 million resulting from lower pension and other postretirement benefit expenses, partially offset by incremental merger-related integration costs.
- A decrease of $1 million resulting from the 2013 write-off of disallowed MAPP costs.

The aggregate amount of these decreases was partially offset by an increase of $1 million in bad debt expense.

Depreciation and Amortization

Depreciation and Amortization expense increased by $16 million to $112 million in 2014 from $96 million in 2013 primarily due to:

- An increase of $5 million in amortization of regulatory assets primarily associated with the EmPower Maryland surcharge rate increase effective February 2014 (which is offset in Regulated T&D Electric Revenue).
- An increase of $4 million in amortization of MAPP abandonment costs (which is offset in Regulated T&D Electric Revenue).
- An increase of $5 million due to utility plant additions.
- An increase of $2 million in amortization of regulatory assets primarily related to recoverable major storm costs and rate case costs.

Other Taxes

Other Taxes increased by $3 million to $180 million in 2014 from $177 million in 2013. The increase was primarily due to higher property taxes in Maryland.

Other Income (Expenses)

Other Expenses (which are net of Other Income) decreased by $7 million to a net expense of $38 million in 2014 from a net expense of $45 million in 2013. The decrease was primarily due to an $8 million gain recorded in 2014 associated with the condemnation of certain transmission property.

Income Tax Expense

Pepco's income tax expense increased by $22 million to $44 million in 2014 from $22 million in 2013. Pepco's effective income tax rates for the six months ended June 30, 2014 and 2013 were 36.1% and 26.8%, respectively. The increase in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions and a reduction in asset removal costs.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which Pepco is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded an after-tax charge of $377 million in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in Pepco recording a $5 million interest benefit in the first quarter of 2013.

Capital Requirements

Capital Expenditures

Pepco's capital expenditures for the six months ended June 30, 2014 were $241 million. These expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. The expenditures also include an allocation by PHI of hardware and software expenditures that primarily benefit Power Delivery and are allocated to Pepco when the assets are placed in service.

In its 2013 Form 10-K, Pepco presented its projected capital expenditures for the five-year period 2014 through 2018, which reflected aggregate expenditures of $3,001 million. Projected capital expenditures include expenditures for distribution and transmission, which primarily relate to facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts. These projected capital expenditures also include expenditures for the smart grid programs undertaken by Pepco to install smart meters, further automate electric distribution systems and enhance Pepco's communications infrastructure. During the first and second quarters of 2014, Pepco added to its projected capital expenditures certain additional transmission projects and the District of Columbia Power Line Undergrounding initiative with aggregate projected capital expenditures of approximately $392 million over the five-year period 2014 through 2018, which will result in additional expenditures of approximately $21 million in 2014, $91 million in 2015, $105 million in 2016, $100 million in 2017 and $75 million in 2018.

Pepco has several construction projects under the General Services Administration area-wide agreement within its service territory where its affiliate Pepco Energy Services has agreed to perform the work. PHI and Pepco guarantee the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for these projects. These guarantees totaled $39 million at June 30, 2014.

DOE Capital Reimbursement Awards

During 2009, the DOE announced a $168 million award to PHI under the American Recovery and Reinvestment Act of 2009 for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure. Pepco was awarded $149 million, with $105 million to be used in the Maryland service territory and $44 million to be used in the District of Columbia service territory.

During 2010, Pepco and the DOE signed agreements formalizing Pepco's $149 million share of the $168 million award. Of the $149 million, $118 million is being used for the smart grid and other capital expenditures of Pepco. The remaining $31 million is being used to offset incremental expenditures associated with direct load control and other programs. For the six months ended June 30, 2014, Pepco received award payments of $3 million. Cumulative award payments received by Pepco as of June 30, 2014 were $148 million.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Delmarva Power & Light Company

DPL meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

DPL is engaged in the transmission and distribution of electricity in portions of Delaware and Maryland. DPL also provides Default Electricity Supply. DPL's electricity distribution service territory covers approximately 5,000 square miles and, as of June 30, 2014, had a population of approximately 1.4 million. As of June 30, 2014, approximately 66% of delivered electricity sales were to Delaware customers and approximately 34% were to Maryland customers. In northern Delaware, DPL also supplies and distributes natural gas to retail customers and provides transportation-only services to retail customers who purchase natural gas from other suppliers. DPL's natural gas distribution service territory covers approximately 275 square miles and, as of June 30, 2014, had a population of approximately 500,000.

DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a BSA for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland retail distribution sales falls short of the revenue that DPL is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that DPL is entitled to earn based on the approved distribution charge per customer.

DPL is a wholly owned subsidiary of Conectiv, LLC (Conectiv) which is wholly owned by PHI. Because each of PHI and Conectiv is a public utility holding company subject to PUHCA 2005, the relationship between each of PHI, Conectiv, PHI Service Company and DPL, as well as certain activities of DPL, are subject to FERC's regulatory oversight under PUHCA 2005.

Agreement and Plan of Merger

PHI has entered into the Merger Agreement with Exelon and Merger Sub. For additional information regarding the Merger, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger."

Utility Capital Expenditures

DPL devotes a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territories. These activities include one or more of the following:

- Identifying and upgrading under-performing feeder lines;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

Smart Grid

DPL is building a smart grid which is designed to meet the challenges of rising energy costs, improve service reliability of the energy distribution system, provide timely and accurate customer information and address government energy reduction goals. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid Initiatives."

Mitigation of Regulatory Lag

An important factor in the ability of DPL to earn its authorized ROE is the willingness of the DPSC and the MPSC to adequately address the shortfall in revenues in DPL's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." DPL is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

MAPP Settlement Agreement

In February 2014, FERC issued an order approving the settlement agreement submitted by DPL in connection with DPL's proceeding seeking recovery of approximately $38 million in abandonment costs related to the MAPP project. DPL had been directed by PJM to construct the MAPP project, a 152-mile high-voltage interstate transmission line, and was subsequently directed by PJM to cancel it. The abandonment costs sought for recovery were subsequently reduced to $37 million from write-offs of certain disallowed costs in 2013. Under the terms of the FERC-approved settlement agreement, DPL will receive $36.6 million of transmission revenues over a three-year period, which began on June 1, 2013, and will retain title to all real property and property rights acquired in connection with the MAPP project, which had an estimated fair value of $6 million. The FERC-approved settlement agreement resolves all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project, and the terms of the settlement agreement are not subject to modification through any other FERC proceeding. As of June 30, 2014, DPL had a regulatory asset related to the MAPP abandonment costs of approximately $19 million, net of amortization, and land of $6 million. DPL expects to recognize pre-tax income related to the MAPP abandonment costs of $3 million in 2014 and $1 million in 2015.

Transmission ROE Challenge

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against DPL, among others. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that DPL provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for DPL is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. DPL believes the allegations in this complaint are without merit and is vigorously contesting it. In April 2013, DPL filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. DPL cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, PHI is permitted, and intends to continue, to pursue the conclusion of this matter.

On June 19, 2014, FERC issued an order in a proceeding in which DPL was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint filed against DPL and its utility affiliates, DPL believes that it is probable that FERC will direct DPL to use this methodology at the time it issues an order addressing the complaint. As a result, DPL applied an estimated ROE based on the two-step methodology announced by FERC for the period over which DPL's transmission revenues would be subject to refund as a result of the challenge, and has recorded an estimated reserve in the second quarter of 2014 related to this matter.

Earnings Overview

Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

DPL's net income for the six months ended June 30, 2014 was $56 million compared to $38 million for the six months ended June 30, 2013. The $18 million increase in earnings was primarily due to the following:

- An increase of $9 million from electric distribution base rate increases in Maryland and Delaware.
- An increase of $3 million primarily due to higher sales from colder winter weather, partially offset by lower sales from milder spring weather.
- An increase of $3 million due to customer growth.
- An increase of $2 million from a gas distribution base rate increase.
- An increase of $2 million due to higher transmission revenue attributable to a change in FERC formula rates.
- A decrease of $2 million due to higher depreciation and amortization expense associated primarily with regulatory assets and increases in plant investment.

Results of Operations

The following results of operations discussion compares the six months ended June 30, 2014 to the six months ended June 30, 2013. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of DPL's statement of income for the six months ended June 30, 2014 compared to the six months ended June 30, 2013, is set forth in the table below:

	2014	2013	Change
Operating revenue	$676	$636	$ 40
Purchased energy	282	280	2
Gas purchased	71	69	2
Other operation and maintenance	131	132	(1)
Depreciation and amortization	60	52	8
Other taxes	21	19	2
Total operating expenses	565	552	13
Operating income	111	84	27
Other income (expenses)	(17)	(21)	4
Income before income tax expense	94	63	31
Income tax expense	38	25	13
Net income	$ 56	$ 38	$ 18

Electric Operating Revenue

	2014	2013	Change
Regulated T&D Electric Revenue	$273	$243	$ 30
Default Electricity Supply Revenue	270	272	(2)
Other Electric Revenue	8	7	1
Total Electric Operating Revenue	$551	$522	$ 29

The table above shows the amount of Electric Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to DPL's customers within its service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2014	2013	Change
Regulated T&D Electric Revenue			
Residential	$ 122	$ 112	$ 10
Commercial and industrial	75	70	5
Transmission and other	76	61	15
Total Regulated T&D Electric Revenue	$ 273	$ 243	$ 30

	2014	2013	Change
Regulated T&D Electric Sales (GWh)			
Residential	2,708	2,561	147
Commercial and industrial	3,540	3,628	(88)
Transmission and other	24	24	—
Total Regulated T&D Electric Sales	6,272	6,213	59

	2014	2013	Change
Regulated T&D Electric Customers (in thousands)			
Residential	447	444	3
Commercial and industrial	60	60	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	508	505	3

Regulated T&D Electric Revenue increased by $30 million primarily due to:

- An increase of $12 million due to electric distribution base rate increases in Maryland effective September 2013 and in Delaware effective October 2013.
- An increase of $6 million in transmission revenue resulting from higher rates effective June 1, 2014 and June 1, 2013 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE complaint.
- An increase of $5 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset in Purchased Energy and Depreciation and Amortization).
- An increase of $4 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $2 million due to higher sales primarily as a result of colder weather during the 2014 winter months, partially offset by milder weather during the spring months, as compared to 2013.
- An increase of $2 million due to customer growth in 2014, primarily in the residential and commercial customer classes.
- An increase of $1 million due to an EmPower Maryland rate increase effective February 2014 (which is substantially offset by a corresponding increase in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by a decrease of $5 million primarily due to a rate decrease effective May 2013 associated with the Renewable Portfolio Surcharge in Delaware (which is substantially offset in Fuel and Purchased Energy and Depreciation and Amortization).

Default Electricity Supply

	2014	2013	Change
Default Electricity Supply Revenue			
Residential	$ 209	$ 211	$ (2)
Commercial and industrial	55	55	—
Other	6	6	—
Total Default Electricity Supply Revenue	$ 270	$ 272	$ (2)

	2014	2013	Change
Default Electricity Supply Sales (GWh)			
Residential	2,305	2,256	49
Commercial and industrial	659	663	(4)
Other	13	13	—
Total Default Electricity Supply Sales	2,977	2,932	45

	2014	2013	Change
Default Electricity Supply Customers (in thousands)			
Residential	390	399	(9)
Commercial and industrial	38	39	(1)
Other	—	—	—
Total Default Electricity Supply Customers	428	438	(10)

Default Supply Revenue decreased by $2 million primarily due to:

- A decrease of $7 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $6 million as a result of lower Default Electricity Supply rates.

The aggregate amount of these decreases was partially offset by:

- An increase of $8 million due to higher sales primarily as a result of colder weather during the 2014 winter months, as compared to 2013.
- An increase of $3 million due to higher non-weather related average customer usage.

The following table shows the percentages of DPL's total distribution sales by jurisdiction that are derived from customers receiving Default Electricity Supply from DPL. Amounts are for the six months ended June 30:

	2014	2013
Sales to Delaware customers	45%	44%
Sales to Maryland customers	53%	52%

Natural Gas Operating Revenue

	2014	2013	Change
Regulated Gas Revenue	$112	$ 97	$ 15
Other Gas Revenue	13	17	(4)
Total Natural Gas Operating Revenue	$125	$114	$ 11

The table above shows the amounts of Natural Gas Operating Revenue from sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated Gas Revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other Gas Revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Regulated Gas

	2014	2013	Change
Regulated Gas Revenue			
Residential	$ 68	$ 62	$ 6
Commercial and industrial	38	29	9
Transportation and other	6	6	—
Total Regulated Gas Revenue	$ 112	$ 97	$ 15

	2014	2013	Change
Regulated Gas Sales (million cubic feet)			
Residential	5,710	4,959	751
Commercial and industrial	3,540	2,669	871
Transportation and other	3,662	3,886	(224)
Total Regulated Gas Sales	12,912	11,514	1,398

	2014	2013	Change
Regulated Gas Customers (in thousands)			
Residential	117	115	2
Commercial and industrial	9	10	(1)
Transportation and other	—	—	—
Total Regulated Gas Customers	126	125	1

Regulated Gas Revenue increased by $15 million primarily due to:

- An increase of $9 million due to higher sales primarily as a result of colder weather during the winter months of 2014 as compared to 2013.
- An increase of $7 million due to a distribution rate increase effective July 2013.
- An increase of $4 million due to higher non-weather related average customer usage.
- An increase of $2 million due to customer growth primarily in the residential customer class.

The aggregate amount of these increases was partially offset by a decrease of $7 million due to a GCR decrease effective November 2013.

Other Gas Revenue

Other Gas Revenue decreased by $4 million primarily due to lower average prices and lower volumes for off-system sales to electric generators and gas marketers.

Operating Expenses

Purchased Energy consists of the cost of electricity purchased by DPL to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy increased by $2 million to $282 million in 2014 from $280 million in 2013 primarily due to:

- An increase of $8 million due to higher electricity sales primarily as a result of colder weather during the 2014 winter months, as compared to 2013.
- An increase of $4 million due to deferred electricity expense primarily due to higher revenue associated with Default Electricity Supply sales, which resulted in higher rate of recovery of Default Electricity Supply costs.
- An increase of $2 million due to Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $3 million primarily due to customer migration to competitive suppliers.

Gas Purchased

Gas Purchased consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales. Total Gas Purchased increased by $2 million to $71 million in 2014 from $69 million in 2013 primarily due to:

- An increase of $19 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.

The increase was partially offset by:

- A decrease of $7 million in the cost of gas purchases for off-system sales as a result of lower volumes.

- A decrease of $6 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.
- A decrease of $4 million in deferred gas expense as a result of a lower rate of recovery of natural gas supply costs.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $1 million to $131 million in 2014 from $132 million in 2013 primarily due to:

- A decrease of $3 million in customer service and system support costs.
- A decrease of $2 million resulting from the 2013 write-offs of disallowed MAPP and associated transmission project costs.
- A decrease of $1 million resulting from lower pension and other postretirement benefit expenses, partially offset by incremental merger-related integration costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $2 million in emergency restoration costs.
- An increase of $1 million associated with higher tree trimming costs.
- An increase of $1 million in bad debt expenses.

Depreciation and Amortization

Depreciation and Amortization expense increased by $8 million to $60 million in 2014 from $52 million in 2013 primarily due to:

- An increase of $4 million due to utility plant additions.
- An increase of $3 million in amortization of MAPP abandonment costs (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $3 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.

The aggregate amount of these increases was partially offset by a decrease of $2 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Fuel and Purchased Energy).

Other Income (Expenses)

Other Expenses (which are net of Other Income) decreased by $4 million to a net expense of $17 million in 2014 from a net expense of $21 million in 2013. The decrease was primarily due to lower long-term debt interest expense.

<u>Income Tax Expense</u>

DPL's income tax expense increased by $13 million to $38 million in 2014 from $25 million in 2013. DPL's effective income tax rates for the six months ended June 30, 2014 and 2013 were 40.4% and 39.7%, respectively. The increase in the effective tax rate primarily resulted from a decrease in changes in estimates and interest related to uncertain and effectively settled tax positions that occurred during the first quarter of 2013.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which DPL is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded an after-tax charge of $377 million in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in DPL recording a $1 million interest benefit in the first quarter of 2013.

Capital Requirements

Capital Expenditures

DPL's capital expenditures for the six months ended June 30, 2014 were $172 million. These expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. The expenditures also include an allocation by PHI of hardware and software expenditures that primarily benefit Power Delivery and are allocated to DPL when the assets are placed in service.

In its 2013 Form 10-K, DPL presented the projected capital expenditures for the five-year period 2014 through 2018, which reflected aggregate expenditures of the $1,614 million. There have been no changes in DPL's projected capital expenditures from those presented in the 2013 Form 10-K. Projected capital expenditures include expenditures for distribution, transmission, and gas delivery which primarily relate to facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts. These projected capital expenditures also include expenditures for the programs undertaken by DPL to install smart meters, further automate electric distribution systems and enhance DPL's communications infrastructure, which is referred to as the smart grid.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Atlantic City Electric Company

ACE meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

ACE is engaged in the transmission and distribution of electricity in portions of southern New Jersey. ACE also provides Default Electricity Supply. Default Electricity Supply is known as BGS in New Jersey. ACE's service territory covers approximately 2,700 square miles and, as of June 30, 2014, had a population of approximately 1.1 million.

ACE is a wholly owned subsidiary of Conectiv, which is wholly owned by PHI. Because each of PHI and Conectiv is a public utility holding company subject to PUHCA 2005, the relationship between each of PHI, Conectiv, PHI Service Company and ACE, as well as certain activities of ACE, are subject to FERC's regulatory oversight under PUHCA 2005.

Agreement and Plan of Merger

PHI has entered into the Merger Agreement with Exelon and Merger Sub. For additional information regarding the Merger, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger."

Utility Capital Expenditures

ACE devotes a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territory. These activities include one or more of the following:

- Identifying and upgrading under-performing feeder lines;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

Mitigation of Regulatory Lag

An important factor in the ability of ACE to earn its authorized ROE is the willingness of the NJBPU to adequately address the shortfall in revenues in ACE's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." ACE is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

Transmission ROE Challenge

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against ACE, among others. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that ACE provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for ACE is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. ACE believes the allegations in this complaint are without merit and is vigorously contesting it. In April 2013, ACE filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. ACE cannot predict when a final FERC decision in this proceeding will be issued. Under the Merger Agreement, PHI is permitted, and intends to continue, to pursue the conclusion of this matter.

On June 19, 2014, FERC issued an order in a proceeding in which ACE was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. Although FERC has not yet issued an order related to the February 2013 complaint filed against ACE and its utility affiliates, ACE believes that it is probable that FERC will direct ACE to use this methodology at the time it issues an order addressing the complaint. As a result, ACE applied an estimated ROE based on the two-step methodology announced by FERC for the period over which ACE's transmission revenues would be subject to refund as a result of the challenge, and has recorded an estimated reserve in the second quarter of 2014 related to this matter.

Earnings Overview

Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

ACE's consolidated net income for the six months ended June 30, 2014 was $16 million compared to $16 million for the six months ended June 30, 2013. Earnings drivers were primarily due to the following:

- An increase of $11 million from electric distribution base rate increases in New Jersey.
- An increase of $3 million due to lower operation and maintenance expense primarily associated with higher tree trimming and maintenance costs in 2013.
- An increase of $2 million due to higher transmission revenue attributable to a change in FERC formula rates and a peak-load rate increase effective January 2014.
- An increase of $1 million primarily due to higher sales from colder winter weather, partially offset by lower sales from milder spring weather.
- A decrease of $7 million due to higher amortization expense of regulatory assets.
- A decrease of $5 million due to lower tax benefits related to uncertain and effectively settled tax positions.
- A decrease of $5 million associated with ACE Basic Generation Service primarily attributable to a decrease in unbilled revenue due to lower usage.

Results of Operations

The following results of operations discussion compares the six months ended June 30, 2014 to the six months ended June 30, 2013. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of ACE's consolidated statement of income for the six months ended June 30, 2014 compared to the six months ended June 30, 2013, is set forth in the table below:

	2014	2013	Change
Operating revenue	$593	$548	$ 45
Purchased energy	316	311	5
Other operation and maintenance	113	119	(6)
Depreciation and amortization	75	63	12
Other taxes	2	6	(4)
Deferred electric service costs	31	(3)	34
Total operating expenses	537	496	41
Operating income	56	52	4
Other income (expenses)	(30)	(35)	5
Income before income tax expense	26	17	9
Income tax expense	10	1	9
Net Income	$ 16	$ 16	$ —

Operating Revenue

	2014	2013	Change
Regulated T&D Electric Revenue	$208	$190	$ 18
Default Electricity Supply Revenue	378	350	28
Other Electric Revenue	7	8	(1)
Total Operating Revenue	$593	$548	$ 45

The table above shows the amount of Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to ACE's customers within its service territory at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, and revenue in the form of transmission enhancement credits.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2014	2013	Change
Regulated T&D Electric Revenue			
Residential	$ 89	$ 79	$ 10
Commercial and industrial	73	68	5
Transmission and other	46	43	3
Total Regulated T&D Electric Revenue	$ 208	$ 190	$ 18

	2014	2013	Change
Regulated T&D Electric Sales (GWh)			
Residential	1,906	1,915	(9)
Commercial and industrial	2,384	2,415	(31)
Transmission and other	22	23	(1)
Total Regulated T&D Electric Sales	4,312	4,353	(41)

	2014	2013	Change
Regulated T&D Electric Customers (in thousands)			
Residential	479	478	1
Commercial and industrial	65	65	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	545	544	1

Regulated T&D Electric Revenue increased by $18 million primarily due to:

- An increase of $18 million due to distribution rate increases effective July 2013.
- An increase of $5 million primarily due to a rate increase in the New Jersey Societal Benefit Charge effective January 2014 (which is offset in Depreciation & Amortization and Deferred Electric Service Costs).
- An increase of $3 million in transmission revenue resulting from higher rates effective June 1, 2014 and June 1, 2013 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE complaint.
- An increase of $1 million due to higher sales primarily as a result of colder weather during the 2014 winter months, partially offset by milder weather during the spring months, as compared to 2013.

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million due to the expiration of the Transitional Energy Facility Assessment effective December 2013 (which is offset in Other Taxes).
- A decrease of $4 million due to lower non-weather related average residential and commercial customer usage.

Default Electricity Supply

	2014	2013	Change
Default Electricity Supply Revenue			
Residential	$163	$198	$ (35)
Commercial and industrial	91	97	(6)
Other	124	55	69
Total Default Electricity Supply Revenue	$378	$350	$ 28

Other Default Electricity Supply Revenue consists primarily of (i) revenue from the resale in the PJM RTO market of energy and capacity purchased under contracts with unaffiliated NUGs and (ii) revenue from transmission enhancement credits.

	2014	2013	Change
Default Electricity Supply Sales (GWh)			
Residential	1,566	1,510	56
Commercial and industrial	497	494	3
Other	5	7	(2)
Total Default Electricity Supply Sales	2,068	2,011	57

	2014	2013	Change
Default Electricity Supply Customers (in thousands)			
Residential	406	386	20
Commercial and industrial	44	44	—
Other	—	—	—
Total Default Electricity Supply Customers	450	430	20

Default Electricity Supply Revenue increased by $28 million primarily due to:

- An increase of $69 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.
- An increase of $11 million due to higher sales, primarily as a result of customer migration from competitive suppliers.
- An increase of $3 million due to lower sales primarily as a result of colder weather during the 2014 winter months, as compared to 2013.

The aggregate amount of these increases was partially offset by:

- A decrease of $52 million as a result of lower Default Electricity Supply rates.
- A decrease of $3 million due to lower non-weather related average commercial customer usage.

The variances described above with respect to Default Electricity Supply Revenue include the effects of a reduction of $8 million in ACE's BGS unbilled revenue resulting primarily from lower usage in the unbilled revenue period at June 30, 2014 as compared to the corresponding period at June 30 2013. Such a decrease in ACE's BGS unbilled revenue has the effect of directly decreasing the profitability of ACE's Default Electricity Supply business ($5 million decrease in net income) as these unbilled revenues are not included in the deferral calculation until they are billed to customers under the BGS terms approved by the NJBPU.

For the six months ended June 30, 2014 and 2013, the percentages of ACE's total distribution sales that are derived from customers receiving Default Electricity Supply are 48% and 46%, respectively.

Operating Expenses

Purchased Energy

Purchased Energy consists of the cost of electricity purchased by ACE to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy increased by $5 million to $316 million in 2014 from $311 million in 2013 primarily due to:

- An increase of $8 million primarily due to customer migration from competitive suppliers.
- An increase of $2 million due to higher electricity sales, primarily as a result of colder weather during the 2014 winter months, as compared to 2013.

The aggregate amount of these increases was partially offset by a decrease of $5 million due to lower average electricity costs under BGS contracts.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $6 million to $113 million in 2014 from $119 million in 2013 primarily due to:

- A decrease of $4 million associated with higher tree trimming costs in 2013.
- A decrease of $2 million in customer service and system support costs.

The aggregate amount of these decreases was partially offset by an increase of $1 million resulting from incremental merger-related integration costs, partially offset by lower pension and other postretirement benefit expenses.

Depreciation and Amortization

Depreciation and Amortization expense increased by $12 million to $75 million in 2014 from $63 million in 2013 primarily due to:

- An increase of $9 million in amortization due to the expiration of the excess depreciation reserve regulatory liability in August 2013.
- An increase of $6 million in amortization of major storm costs.

The aggregate amount of these increases was partially offset by:

- A decrease of $2 million due to lower depreciation expense.
- A decrease of $2 million in amortization of stranded costs primarily as the result of lower revenue as the result of lower sales for the ACE Transition Bond Charge and Market Transition charge tax (partially offset in Default Electricity Supply Revenue).

Other Taxes

Other Taxes decreased by $4 million to $2 million in 2014 from $6 million in 2013. The decrease was primarily due to the expiration of Transitional Energy Facility Assessment effective December 2013 (which is offset by a corresponding decrease in Regulated T&D Electric Revenue).

Deferred Electric Service Costs

Deferred Electric Service Costs represent (i) the over or under recovery of electricity costs incurred by ACE to fulfill its Default Electricity Supply obligation and (ii) the over or under recovery of New Jersey Societal Benefit Program costs incurred by ACE. The cost of electricity purchased is reported under Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of the New Jersey Societal Benefit Program is reported under Other Operation and Maintenance expense and the corresponding revenue is reported under Regulated T&D Electric Revenue.

Deferred Electric Service Costs increased by $34 million to an expense of $31 million in 2014 as compared to an expense reduction of $3 million in 2013, primarily due to an increase in deferred electricity expense as a result of higher wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from the NUGs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) decreased by $5 million to a net expense of $30 million in 2014 from a net expense of $35 million in 2013. The decrease was primarily due to lower long-term debt interest expense.

Income Tax Expense

ACE's consolidated income tax expense increased by $9 million to $10 million in 2014 from $1 million in 2013. ACE's consolidated effective income tax rates for the six months ended June 30, 2014 and 2013 were 38.5% and 5.9%, respectively. The change in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions. In the first quarter of 2013, ACE recorded an interest benefit of $6 million as discussed further below.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which ACE is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded an after-tax charge of $377 million in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in ACE recording a $6 million interest benefit in the first quarter of 2013.

Capital Requirements

Capital Expenditures

ACE's capital expenditures for the six months ended June 30, 2014 were $104 million. These expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. The expenditures also include an allocation by PHI of hardware and software expenditures that primarily benefit Power Delivery and are allocated to ACE when the assets are placed in service.

In its 2013 Form 10-K, ACE presented the projected capital expenditures for the five-year period 2014 through 2018, which reflected aggregate expenditures of $1,199 million. Projected capital expenditures include expenditures for distribution and transmission, which primarily relate to facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts. These projected capital expenditures also include expenditures for the smart grid programs undertaken by ACE to install smart meters (for which approval by the NJBPU has been deferred), further automate electric distribution systems and enhance ACE's communications infrastructure. During the first quarter of 2014, ACE added to its projected capital expenditures an additional transmission project with aggregate projected capital expenditures of approximately $41 million over the five-year period 2014 through 2018, which will result in additional expenditures of approximately $6 million in 2014, $5 million in 2015, $16 million in 2016, $13 million in 2017 and $1 million in 2018.

DOE Capital Reimbursement Awards

During 2009, the DOE announced a $168 million award to PHI under the American Recovery and Reinvestment Act of 2009 for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure, of which $19 million was for ACE's service territory.

During 2010, ACE and the DOE signed agreements formalizing ACE's $19 million share of the $168 million award. Of the $19 million, $12 million is being used for the smart grid and other capital expenditures of ACE. The remaining $7 million is being used to offset incremental expenditures associated with direct load control and other programs. For the six months ended June 30, 2014, ACE received award payments of $1 million. Cumulative award payments received by ACE as of June 30, 2014 were $19 million.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk management policies for PHI and its subsidiaries are determined by PHI's Corporate Risk Management Committee (CRMC), the members of which are PHI's Chief Risk Officer, Chief Operating Officer, Chief Financial Officer, General Counsel, Chief Information Officer and other senior executives. The CRMC monitors interest rate fluctuation, commodity price fluctuation, credit risk exposure, and sets risk management policies that establish limits on unhedged risk and determine risk reporting requirements. For information about PHI's derivative activities, other than the information otherwise disclosed herein, refer to Note (2), "Significant Accounting Policies – Accounting For Derivatives," Note (13), "Derivative Instruments and Hedging Activities," and Note (19), "Discontinued Operations," of the consolidated financial statements of PHI included in its 2013 Form 10-K, Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" in PHI's 2013 Form 10-K, and Note (13), "Derivative Instruments and Hedging Activities," and Note (18), "Discontinued Operations," of the consolidated financial statements of PHI included herein.

For information regarding "Interest Rate Risk," please refer to Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk," in Pepco Holdings' 2013 Form 10-K.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND THEREFORE ARE FILING THIS FORM WITH A REDUCED FILING FORMAT.

Item 4. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Each Reporting Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in such Reporting Company's reports under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to management of such Reporting Company, including such Reporting Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), as appropriate, to allow timely decisions regarding required disclosure. This control system, no matter how well designed and operated, can provide only reasonable assurance that the objectives of the control system are met. Such Reporting Company's disclosure controls and procedures were designed to provide reasonable assurance of achieving their stated objectives. Under the supervision, and with the participation of management, including the CEO and the CFO, each Reporting Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2014, and, based upon this evaluation, the CEO and the CFO of such Reporting Company have concluded that these disclosure controls and procedures are effective to provide reasonable assurance that material information relating to such Reporting Company and its subsidiaries that is required to be disclosed in reports filed with, or submitted to, the SEC under the Exchange Act (i) is recorded, processed, summarized and reported within the time periods specified by the SEC rules and forms and (ii) is accumulated and communicated to management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Reports of Changes in Internal Control Over Financial Reporting

Under the supervision and with the participation of management, including the CEO and CFO of each Reporting Company, each such Reporting Company has evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the three months ended June 30, 2014, and has concluded there was no change in such Reporting Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, such Reporting Company's internal control over financial reporting.

Transition to COSO 2013

In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) released COSO 2013, an updated version of its *Internal Control – Integrated Framework (1992).* The COSO 2013 Framework formalizes the principles embedded in the original COSO 1992, incorporates business and operating environment changes over the past two decades, and improves the original 1992 framework's ease of use and application. During the second quarter 2014, each Reporting Company continued to assess its internal controls over financial reporting using COSO 1992, and will be transitioning to COSO 2013 in the fourth quarter of 2014. None of the Reporting Companies expects that its transition to COSO 2013 will have a significant impact on its underlying compliance with the applicable provisions of the Sarbanes-Oxley Act of 2002, including internal control over financial reporting and disclosure controls and procedures.

Part II OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Pepco Holdings

Other than ordinary routine litigation incidental to its and its subsidiaries' business, PHI is not a party to, and its subsidiaries' property is not subject to, any material pending legal proceedings except as described in Note (15), "Commitments and Contingencies," to the consolidated financial statements of PHI included herein, which description is incorporated by reference herein.

Pepco

Other than ordinary routine litigation incidental to its business, Pepco is not a party to, and its property is not subject to, any material pending legal proceedings except as described in Note (11), "Commitments and Contingencies," to the financial statements of Pepco included herein, which description is incorporated by reference herein.

DPL

Other than ordinary routine litigation incidental to its business, DPL is not a party to, and its property is not subject to, any material pending legal proceedings except as described in Note (13), "Commitments and Contingencies," to the financial statements of DPL included herein, which description is incorporated by reference herein.

ACE

Other than ordinary routine litigation incidental to its business, ACE is not a party to, and its property is not subject to, any material pending legal proceedings except as described in Note (11), "Commitments and Contingencies," to the consolidated financial statements of ACE included herein, which description is incorporated by reference herein.

Item 1A. RISK FACTORS

For a discussion of the risk factors applicable to each Reporting Company, please refer to Part I, Item 1A. "Risk Factors" in each Reporting Company's 2013 Form 10-K. There have been no material changes to any Reporting Company's risk factors as disclosed in the 2013 Form 10-K, except as set forth below:

PHI and Exelon may be unable to obtain the required governmental, regulatory and other approvals required to complete the Merger, or such approvals may require the combined company to comply with material restrictions or conditions.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of PHI's common stock, (ii) the receipt of regulatory approvals required to consummate the Merger, including from FERC, the DCPSC, the MPSC, the DPSC and the NJBPU, among others, (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and (iv) other customary closing conditions. The regulatory and other approvals required to consummate the Merger may not be obtained at all, may not be obtained on the proposed terms and schedules as contemplated by the parties, and/or may impose terms, conditions, obligations or commitments that constitute a "burdensome condition" (as defined in the Merger Agreement). In the event that the regulatory approvals include any such burdensome conditions, or if any of the conditions to closing are not satisfied prior to the termination date specified in the Merger Agreement, Exelon will not be obligated to consummate the Merger.

In the event that the Merger Agreement is terminated prior to the completion of the Merger, PHI could incur significant transaction costs that could materially impact its financial performance and results.

PHI will incur significant transaction costs, including legal, accounting, financial advisory, filing, printing and other costs, relating to the Merger. If (i) the Merger Agreement is terminated under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Parent expenses up to $40 million (which reimbursement shall reduce on a dollar for dollar basis any termination fee subsequently payable by the Company), or (ii) if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, PHI will be required to pay Exelon a termination fee of $293 million plus reimbursement of Parent expenses up to $40 million (not subject to offset). The occurrence of either of these events could have a material adverse effect on PHI's financial results.

PHI and its subsidiaries will be subject to business uncertainties and contractual restrictions while the Merger is pending that could adversely affect PHI's financial results.

Uncertainty about the effect of the Merger on employees or vendors and others may have an adverse effect on PHI. Although PHI intends to take steps designed to reduce any adverse effects, these uncertainties may impair PHI's and its subsidiaries' ability to attract, retain and motivate key personnel until the Merger is completed, and could cause vendors and others that deal with PHI to seek to change existing business relationships. Employee retention and recruitment may be particularly challenging prior to the completion of the Merger, as current employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite PHI's retention and recruiting efforts, key employees depart or fail to accept employment with PHI or its subsidiaries due to the uncertainty and difficulty of integration or a desire not to remain with the combined company, PHI's business operations and financial results could be adversely affected.

PHI expects that matters relating to the Merger and integration-related issues will place a significant burden on management, employees and internal resources, which could otherwise have been devoted to other business opportunities. The diversion of management time on Merger-related issues could affect PHI's financial results. In addition, the Merger Agreement restricts PHI and its subsidiaries, without Exelon's consent, from taking specified actions until the Merger occurs or the Merger Agreement is terminated, including, without limitation: (i) making certain acquisitions and dispositions of assets or property; (ii) exceeding certain capital spending limits; (iii) incurring indebtedness; (iv) issuing equity or equity equivalents; and (v) increasing the dividend rates on its stock. These restrictions may prevent PHI from pursuing otherwise attractive business opportunities and making other changes to its business prior to consummation of the Merger or termination of the Merger Agreement.

Pending or potential future litigation against PHI and its directors challenging the proposed Merger may prevent the Merger from being completed within the anticipated timeframe.

PHI and its directors have been named as defendants in a purported consolidated class action lawsuit filed on behalf of public stockholders challenging the proposed Merger and seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. If a plaintiff in this or any other litigation that may be filed in the future is successful in obtaining an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, the injunction may prevent the completion of the Merger in the expected timeframe or altogether. While PHI believes that this lawsuit is without merit and will not succeed, and intends to vigorously defend itself in this matter, the pending litigation creates additional uncertainty relating to the consummation of the Merger.

Failure to complete the Merger could negatively impact the market price of PHI's common stock.

Failure to complete the Merger may negatively impact the future trading price of PHI's common stock. If the Merger is not completed, the market price of PHI's common stock may decline to the extent that the current market price of PHI's stock reflects a market assumption that the Merger will be completed. Additionally, if the Merger is not completed, PHI will have incurred significant costs, as well as the diversion of the time and attention of management. A failure to complete the Merger may also result in negative publicity, litigation against PHI or its directors and officers, and a negative impression of PHI in the investment community. The occurrence of any of these events individually or in combination could have a material adverse effect on PHI's financial condition, results of operations and its stock price.

Pepco Energy Services' thermal business in Atlantic City, New Jersey is exposed to customer concentration, and the loss of one or more of its significant customers could have a material adverse effect on this business, as well as on Pepco Energy Services' and PHI's financial condition, results of operations and cash flow. (PHI only)

Revenues associated with Pepco Energy Services' combined heat and power thermal generating plant and operation in Atlantic City, New Jersey are derived from long-term contracts with a few major customers in the Atlantic City hotel and casino industry. For the largest customer, these contracts expire in 2017. The Atlantic City hotel and casino industry has been experiencing overcapacity and a decrease in gaming revenues, as well as competition from casinos that have been recently opened in nearby markets. This industry also faces potential competition from new casinos being constructed in nearby markets. Pepco Energy Services is exposed to the risk that it is not able to renew these contracts or that the contract counterparties may fail to perform their obligations thereunder. In July 2014, a significant customer of this thermal operation reported that it is considering closure if it does not find a suitable buyer for its facilities. Future developments with respect to this customer or the thermal business may require Pepco Energy Services to perform impairment analyses related to the assets of its thermal business, which had an aggregate carrying value as of June 30, 2014 of approximately $85 million. If assets of the thermal business are determined to be impaired, Pepco Energy Services would reduce the carrying value of these assets by the amount of the impairment and record a corresponding non-cash charge to earnings. Moreover, such a closure or cessation of operations by this or any other thermal business customer could reduce Pepco Energy Services' future earnings associated with the thermal business. The occurrence of these or other similar events with respect to Pepco Energy Services' thermal operation could have a material adverse effect on PHI's and Pepco Energy Services' financial condition, results of operations and cash flow.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Pepco Holdings

None.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND THEREFORE ARE FILING THIS FORM WITH A REDUCED FILING FORMAT.

<u>Item 3</u>. <u>DEFAULTS UPON SENIOR SECURITIES</u>

Pepco Holdings

None.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND THEREFORE ARE FILING THIS FORM WITH A REDUCED FILING FORMAT.

<u>Item 4</u>. <u>MINE SAFETY DISCLOSURES</u>

Not applicable.

<u>Item 5</u>. <u>OTHER INFORMATION</u>

Pepco Holdings

None.

Pepco

None.

DPL

None.

ACE

None.

Item 6. EXHIBITS

The documents listed below are being filed or furnished on behalf of PHI, Pepco, DPL and/or ACE, as indicated. The warranties, representations and covenants contained in any of the agreements included or incorporated by reference herein or which appear as exhibits hereto should not be relied upon by buyers, sellers or holders of PHI's or its subsidiaries' securities and are not intended as warranties, representations or covenants to any individual or entity except as specifically set forth in such agreement.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
2.1	PHI Pepco DPL ACE	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among PHI, Exelon and Merger Sub	Exhibit 2.1 to PHI's Form 8-K, July 21, 2014.
2.2	PHI	Subscription Agreement, dated as of April 29, 2014, between PHI and Exelon	Exhibit 2.2 to PHI's Form 8-K, April 30, 2014.
3.1	PHI	Restated Certificate of Incorporation of Pepco Holdings, Inc. (as filed in Delaware)	Exhibit 3.1 to PHI's Form 10-K, March 13, 2006.
3.2	Pepco	Restated Articles of Incorporation (as filed in the District of Columbia)	Exhibit 3.1 to Pepco's Form 10-Q, May 5, 2006.
3.3	Pepco	Restated Articles of Incorporation and Articles of Restatement (as filed in Virginia)	Exhibit 3.3 to PHI's Form 10-Q, November 4, 2011.
3.4	DPL	Restated Certificate and Articles of Incorporation (as filed in Delaware and Virginia)	Exhibit 3.3 to DPL's Form 10-K, March 1, 2007.
3.5	ACE	Restated Certificate of Incorporation (as filed in New Jersey)	Exhibit B.8.1 to PHI's Amendment No. 1 to Form U5B, February 13, 2003.
3.6	PHI	Certificate of Designation for Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 3.1 to PHI's Form 8-K, April 30, 2014.
3.7	PHI	Bylaws	Exhibit 3.6 to PHI's Form 10-K, March 1, 2013.
3.8	Pepco	By-Laws	Exhibit 3.2 to Pepco's Form 10-Q, May 5, 2006.
3.9	DPL	Amended and Restated Bylaws	Exhibit 3.2.1 to DPL's Form 10-Q, May 9, 2005.
3.10	ACE	Amended and Restated Bylaws	Exhibit 3.2.2 to ACE's Form 10-Q, May 9, 2005.
4.1	DPL	Form of First Mortgage Bond, 3.50% Series due November 15, 2023	Exhibit 4.1 to DPL's Form 8-K, November 8, 2013.
4.2	DPL	One Hundred and Twelfth Supplemental Indenture, dated as of November 7, 2013, with respect to the Mortgage and Deed of Trust, dated October 1, 1943	Exhibit 4.2 to DPL's Form 8-K, November 8, 2013.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
4.3	DPL	One Hundred and Fourteenth Supplemental Indenture, dated as of June 2, 2014, with respect to the Mortgage and Deed of Trust, dated October 1, 1943	Exhibit 4.3 to DPL's Form 8-K, June 3, 2014.
4.4	PHI	Certificate of Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 4.1 to PHI's Form 8-K, April 30, 2014.
10.1	DPL	Purchase Agreement, dated June 2, 2014, among DPL, Morgan Stanley & Co. LLC and SunTrust Robinson Humphrey, Inc., as representatives of the several underwriters named therein	Exhibit 1.1 to DPL's Form 8-K, June 3, 2014.
10.2	PHI	Employment Extension Agreement, dated April 29, 2014, between the Company and Joseph M. Rigby	Exhibit 10.1 to PHI's Form 8-K, May 2, 2014.
10.3	PHI	Restricted Stock Award Agreement (Immediate Vesting), dated April 30, 2014, between the Company and Joseph M. Rigby	Exhibit 10.2 to PHI's Form 8-K, May 2, 2014.
10.4	PHI	Restricted Stock Award Agreement, dated April 30, 2014, between the Company and Joseph M. Rigby	Exhibit 10.3 to PHI's Form 8-K, May 2, 2014.
10.5	PHI	Pepco Holdings, Inc. Management Employee Severance Plan	Exhibit 10.4 to PHI's Form 8-K, May 2, 2014.
10.6	PHI Pepco DPL ACE	Amendment and Consent to Second Amended and Restated Credit Agreement, dated as of May 20, 2014, among the Company, Pepco, DPL, ACE, the lenders party thereto, Bank of America, N.A., as syndication agent and as an issuer of letters of credit, and Wells Fargo Bank, National Association, as agent on behalf of the lenders thereunder, as the swingline lender and as an issuer of letters of credit	Exhibit 10.1 to PHI's Form 8-K, May 20, 2014.
31.1	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.2	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.3	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.4	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.5	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.6	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.7	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.8	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
32.1	PHI	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
32.2	Pepco	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
32.3	DPL	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
32.4	ACE	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
99.1	PHI	Statement Re: Computation of Ratios	Filed herewith.
99.2	Pepco	Statement Re: Computation of Ratios	Filed herewith.
99.3	DPL	Statement Re: Computation of Ratios	Filed herewith.
99.4	ACE	Statement Re: Computation of Ratios	Filed herewith.
101. INS	PHI Pepco DPL ACE	XBRL Instance Document	Filed herewith.
101. SCH	PHI Pepco DPL ACE	XBRL Taxonomy Extension Schema Document	Filed herewith.
101. CAL	PHI Pepco DPL ACE	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith.
101. DEF	PHI Pepco DPL ACE	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith.
101. LAB	PHI Pepco DPL ACE	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith.
101. PRE	PHI Pepco DPL ACE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith.

Regulation S-K Item 10(d) requires registrants to identify the physical location, by SEC file number reference, of all documents incorporated by reference that are not included in a registration statement and have been on file with the SEC for more than five years. The SEC file number references for PHI and each of its subsidiaries that are currently registrants are provided below:

Pepco Holdings, Inc. (File Nos. 001-31403 and 030-00359)
Potomac Electric Power Company (File No. 001-01072)
Delmarva Power & Light Company (File No. 001-01405)
Atlantic City Electric Company (File No. 001-03559)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each of the registrants has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PEPCO HOLDINGS, INC. (PHI)
POTOMAC ELECTRIC POWER COMPANY (Pepco)
DELMARVA POWER & LIGHT COMPANY (DPL)
ATLANTIC CITY ELECTRIC COMPANY (ACE)
(Registrants)

July 31, 2014

By /s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer, PHI, Pepco and DPL
Chief Financial Officer, ACE

INDEX TO EXHIBITS FILED HEREWITH OR INCORPORATED BY REFERENCE HEREIN

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
2.1	PHI Pepco DPL ACE	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among PHI, Exelon and Merger Sub	Exhibit 2.1 to PHI's Form 8-K, July 21, 2014.
2.2	PHI	Subscription Agreement, dated as of April 29, 2014, between PHI and Exelon	Exhibit 2.2 to PHI's Form 8-K, April 30, 2014.
3.1	PHI	Restated Certificate of Incorporation of Pepco Holdings, Inc. (as filed in Delaware)	Exhibit 3.1 to PHI's Form 10-K, March 13, 2006.
3.2	Pepco	Restated Articles of Incorporation (as filed in the District of Columbia)	Exhibit 3.1 to Pepco's Form 10-Q, May 5, 2006.
3.3	Pepco	Restated Articles of Incorporation and Articles of Restatement (as filed in Virginia)	Exhibit 3.3 to PHI's Form 10-Q, November 4, 2011.
3.4	DPL	Restated Certificate and Articles of Incorporation (as filed in Delaware and Virginia)	Exhibit 3.3 to DPL's Form 10-K, March 1, 2007.
3.5	ACE	Restated Certificate of Incorporation (as filed in New Jersey)	Exhibit B.8.1 to PHI's Amendment No. 1 to Form U5B, February 13, 2003.
3.6	PHI	Certificate of Designation for Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 3.1 to PHI's Form 8-K, April 30, 2014.
3.7	PHI	Bylaws	Exhibit 3.6 to PHI's Form 10-K, March 1, 2013.
3.8	Pepco	By-Laws	Exhibit 3.2 to Pepco's Form 10-Q, May 5, 2006.
3.9	DPL	Amended and Restated Bylaws	Exhibit 3.2.1 to DPL's Form 10-Q, May 9, 2005.
3.10	ACE	Amended and Restated Bylaws	Exhibit 3.2.2 to ACE's Form 10-Q, May 9, 2005.
4.1	DPL	Form of First Mortgage Bond, 3.50% Series due November 15, 2023	Exhibit 4.1 to DPL's Form 8-K, November 8, 2013.
4.2	DPL	One Hundred and Twelfth Supplemental Indenture, dated as of November 7, 2013, with respect to the Mortgage and Deed of Trust, dated October 1, 1943	Exhibit 4.2 to DPL's Form 8-K, November 8, 2013.
4.3	DPL	One Hundred and Fourteenth Supplemental Indenture, dated as of June 2, 2014, with respect to the Mortgage and Deed of Trust, dated October 1, 1943	Exhibit 4.3 to DPL's Form 8-K, June 3, 2014.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
4.4	PHI	Certificate of Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 4.1 to PHI's Form 8-K, April 30, 2014.
10.1	DPL	Purchase Agreement, dated June 2, 2014, among DPL, Morgan Stanley & Co. LLC and SunTrust Robinson Humphrey, Inc., as representatives of the several underwriters named therein	Exhibit 1.1 to DPL's Form 8-K, June 3, 2014.
10.2	PHI	Employment Extension Agreement, dated April 29, 2014, between the Company and Joseph M. Rigby	Exhibit 10.1 to PHI's Form 8-K, May 2, 2014.
10.3	PHI	Restricted Stock Award Agreement (Immediate Vesting), dated April 30, 2014, between the Company and Joseph M. Rigby	Exhibit 10.2 to PHI's Form 8-K, May 2, 2014.
10.4	PHI	Restricted Stock Award Agreement, dated April 30, 2014, between the Company and Joseph M. Rigby	Exhibit 10.3 to PHI's Form 8-K, May 2, 2014.
10.5	PHI	Pepco Holdings, Inc. Management Employee Severance Plan	Exhibit 10.4 to PHI's Form 8-K, May 2, 2014.
10.6	PHI Pepco DPL ACE	Amendment and Consent to Second Amended and Restated Credit Agreement, dated as of May 20, 2014, among the Company, Pepco, DPL, ACE, the lenders party thereto, Bank of America, N.A., as syndication agent and as an issuer of letters of credit, and Wells Fargo Bank, National Association, as agent on behalf of the lenders thereunder, as the swingline lender and as an issuer of letters of credit	Exhibit 10.1 to PHI's Form 8-K, May 20, 2014.
31.1	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.2	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.3	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.4	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.5	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.6	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.7	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.8	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
99.1	PHI	Statement Re: Computation of Ratios	Filed herewith.
99.2	Pepco	Statement Re: Computation of Ratios	Filed herewith.
99.3	DPL	Statement Re: Computation of Ratios	Filed herewith.
99.4	ACE	Statement Re: Computation of Ratios	Filed herewith.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
101.INS	PHI Pepco DPL ACE	XBRL Instance Document	Filed herewith.
101.SCH	PHI Pepco DPL ACE	XBRL Taxonomy Extension Schema Document	Filed herewith.
101.CAL	PHI Pepco DPL ACE	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith.
101. DEF	PHI Pepco DPL ACE	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith.
101.LAB	PHI Pepco DPL ACE	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith.
101. PRE	PHI Pepco DPL ACE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith.

INDEX TO EXHIBITS FURNISHED HEREWITH

Exhibit No.	Registrant(s)	Description of Exhibit
32.1	PHI	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.2	Pepco	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.3	DPL	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.4	ACE	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350

Exhibit 31.1

CERTIFICATION

I, Joseph M. Rigby, certify that:

1. I have reviewed this report on Form 10-Q of Pepco Holdings, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2014

/s/ JOSEPH M. RIGBY
Joseph M. Rigby
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Pepco Holdings, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: July 31, 2014

/s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATION

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-Q of Potomac Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2014

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.4

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Potomac Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: July 31, 2014

/s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer

Exhibit 31.5

CERTIFICATION

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-Q of Delmarva Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2014

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.6

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Delmarva Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2014

/s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer

Exhibit 31.7

CERTIFICATION

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-Q of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2014

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.8

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2014

/s/ FRED BOYLE
Frederick J. Boyle
Chief Financial Officer

Exhibit 32.1

Certificate of Chief Executive Officer and Chief Financial Officer

of

Pepco Holdings, Inc.

(pursuant to 18 U.S.C. Section 1350)

I, Joseph M. Rigby, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Pepco Holdings, Inc. for the quarter ended June 30, 2014, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings, Inc.

July 31, 2014	/s/ JOSEPH M. RIGBY
	Joseph M. Rigby
	Chairman of the Board, President and Chief Executive Officer
July 31, 2014	/s/ FRED BOYLE
	Frederick J. Boyle
	Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Pepco Holdings, Inc. and will be retained by Pepco Holdings, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certificate of Chief Executive Officer and Chief Financial Officer

of

Potomac Electric Power Company

(pursuant to 18 U.S.C. Section 1350)

I, David M. Velazquez, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Potomac Electric Power Company for the quarter ended June 30, 2014, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

July 31, 2014	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
July 31, 2014	/s/ FRED BOYLE Frederick J. Boyle Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Potomac Electric Power Company and will be retained by Potomac Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.3

Certificate of Chief Executive Officer and Chief Financial Officer

of

Delmarva Power & Light Company

(pursuant to 18 U.S.C. Section 1350)

I, David M. Velazquez, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Delmarva Power & Light Company for the quarter ended June 30, 2014, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

July 31, 2014	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
July 31, 2014	/s/ FRED BOYLE Frederick J. Boyle Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Delmarva Power & Light Company and will be retained by Delmarva Power & Light Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.4

Certificate of Chief Executive Officer and Chief Financial Officer

of

Atlantic City Electric Company

(pursuant to 18 U.S.C. Section 1350)

I, David M. Velazquez, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Atlantic City Electric Company for the quarter ended June 30, 2014, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

July 31, 2014	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
July 31, 2014	/s/ FRED BOYLE Frederick J. Boyle Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Atlantic City Electric Company and will be retained by Atlantic City Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

PEPCO HOLDINGS, INC.

	Six Months Ended June 30, 2014	For the Year Ended December 31, 2013	2012	2011	2010	2009
		(millions of dollars)				
Earnings						
Net income from continuing operations	$ 128	$ 110	$ 218	$ 222	$ 91	$ 163
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	(2)	(1)	3	1	(2)
Minority interest loss	—	—	—	—	—	—
Income tax expense (benefit) related to continuing operations	91	319	103	114	(14)	80
Pre-tax income for common stock	219	427	320	339	78	241
Add: Fixed charges*	147	301	286	275	312	332
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 366	$ 728	$ 606	$ 614	$ 390	$ 573
***Fixed Charges**						
Interest on long-term debt	$ 130	$ 265	$ 249	$ 239	$ 269	$ 286
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	6	14	16	14	21	23
Interest component of rentals	11	22	21	22	22	23
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 147	$ 301	$ 286	$ 275	$ 312	$ 332
Ratio of earnings to fixed charges (a)	2.49	2.42	2.12	2.23	1.25	1.73

(a) Pepco Holdings, Inc. issued shares of non-voting, non-convertible and non-transferable Series A preferred stock (Preferred Stock) in the second quarter of 2014 that are excluded from equity since the securities contain conditions for redemption that are not solely within the control of PHI. The dividends associated with the Preferred Stock were immaterial for the six months ended June 30, 2014, and are included in fixed charges as a component of interest on long-term debt. Accordingly, the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 99.2

POTOMAC ELECTRIC POWER COMPANY

	Six Months Ended June 30, 2014	For the Year Ended December 31, 2013	2012	2011	2010	2009
		(millions of dollars)				
Earnings						
Net income for common stock	$ 78	$ 150	$ 126	$ 99	$ 108	$ 106
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	44	79	48	36	37	76
Pre-tax income for common stock	122	229	174	135	145	182
Add: Fixed charges*	63	121	113	111	111	114
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 185	$ 350	$ 287	$ 246	$ 256	$ 296
***Fixed Charges**						
Interest on long-term debt	$ 57	$ 109	$ 101	$ 97	$ 97	$ 99
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	5	5	4	4	4
Interest component of rentals	4	7	7	10	10	11
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 63	$ 121	$ 113	$ 111	$ 111	$ 114
Ratio of earnings to fixed charges (a)	2.94	2.89	2.54	2.22	2.31	2.60

(a) Pepco has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 99.3

DELMARVA POWER & LIGHT COMPANY

	Six Months Ended June 30, 2014	For the Year Ended December 31,				
		2013	2012	2011	2010	2009
		(millions of dollars)				
Earnings						
Net income for common stock	$ 56	$ 89	$ 73	$ 71	$ 45	$ 52
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	38	56	44	42	31	16
Pre-tax income for common stock	94	145	117	113	76	68
Add: Fixed charges*	25	55	52	49	48	47
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 119	$ 200	$ 169	$ 162	$ 124	$ 115
***Fixed Charges**						
Interest on long-term debt	$ 22	$ 49	$ 45	$ 42	$ 43	$ 42
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	1	3	4	4	3	3
Interest component of rentals	2	3	3	3	2	2
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 25	$ 55	$ 52	$ 49	$ 48	$ 47
Ratio of earnings to fixed charges (a)	4.76	3.64	3.25	3.31	2.58	2.45

(a) DPL has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 99.4

ATLANTIC CITY ELECTRIC COMPANY

	Six Months Ended June 30, 2014	For the Year Ended December 31, 2013	2012	2011	2010	2009
			(millions of dollars)			
Earnings						
Net income for common stock	$ 16	$ 50	$ 35	$ 39	$ 53	$ 41
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	10	19	18	33	43	17
Pre-tax income for common stock	26	69	53	72	96	58
Add: Fixed charges*	34	72	75	74	69	72
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 60	$ 141	$ 128	$ 146	$ 165	$ 130
***Fixed Charges**						
Interest on long-term debt	$ 30	$ 65	$ 69	$ 69	$ 63	$ 67
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	3	2	2	3	2
Interest component of rentals	2	4	4	3	3	3
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 34	$ 72	$ 75	$ 74	$ 69	$ 72
Ratio of earnings to fixed charges (a)	1.76	1.96	1.71	1.97	2.39	1.81

(a) ACE has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.