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, 2013

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 25, 2013
Pepco Holdings	249,142,538 ($.01 par value)
Pepco	100 ($.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
2012 Form 10-K	The Annual Report on Form 10-K for the year ended December 31, 2012 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
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
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
DC Undergrounding Task Force	The District of Columbia Mayor’s Power Line Undergrounding Task Force
DCPSC	District of Columbia Public Service Commission
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
DOE	U.S. Department of Energy
DPL	Delmarva Power & Light Company
DPSC	Delaware Public Service Commission
EDCs	Electric distribution companies
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
Energy Services	Energy savings performance contracting services provided principally to federal, state and local government customers, and designing, constructing and operating combined heat and power, and central energy plants by Pepco Energy Services
EPA	U.S Environmental Protection Agency
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
GCR	Gas Cost Rate
GenOn	GenOn MD Ash Management, LLC
GWh	Gigawatt hour
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
ISRA	New Jersey’s Industrial Site Recovery Act
LIBOR	London Interbank Offered Rate
MAPP	Mid-Atlantic Power Pathway

Term	Definition
Market Transition Charge Tax	Revenue ACE receives and pays to ACE Funding to recover income taxes associated with Transition Bond Charge revenue
MDC	MDC Industries, Inc.
MFVRD	Modified fixed variable rate design
MPSC	Maryland Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NJBPU	New Jersey Board of Public Utilities
NOAA	National Oceanic and Atmospheric Administration
NUGs	Non-utility generators
NYMEX	New York Mercantile Exchange
OAL	New Jersey Office of Administrative Law
OPC	Office of People's Counsel
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
PRP	Potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
RARC	ACE's Regulatory Asset Recovery Charge
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
RIM	Reliability investment recovery mechanism
ROE	Return on equity
RPS	Renewable Energy Portfolio Standards
SEC	Securities and Exchange Commission
SEPs	Supplemental Environmental Projects
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
Transition Bonds	Transition Bonds issued by ACE Funding

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:

- 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 for transmission services provided by Pepco, DPL and ACE; (ii) challenges raised in Pepco's and DPL's Federal Energy Regulatory Commission (FERC) proceeding seeking, among other things, recovery of all prudently incurred Mid-Atlantic Power Pathway (MAPP) abandoned costs and the full ROE previously approved by FERC with respect to such costs; and (iii) other possible disallowances of recovery of costs and expenses;
- The resolution of the cross-border lease matter, including 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 conservation measures and the use of more energy-efficient products;
- General economic conditions, including the impact of an economic downturn or recession on energy usage;
- 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 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 domestic 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, 2012 (2012 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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(millions of dollars, except per share data)			
Operating Revenue				
Power Delivery	$ 1,006	$ 984	$2,130	$2,039
Pepco Energy Services	49	76	106	148
Other	(2)	10	(371)	19
Total Operating Revenue	1,053	1,070	1,865	2,206
Operating Expenses				
Fuel and purchased energy	446	465	1,008	1,010
Other services cost of sales	35	49	75	94
Other operation and maintenance	213	220	441	441
Depreciation and amortization	116	111	228	221
Other taxes	101	105	206	209
Loss on early termination of finance leases held in trust	14	—	14	—
Deferred electric service costs	(4)	(20)	(3)	(35)
Impairment losses	—	3	—	3
Total Operating Expenses	921	933	1,969	1,943
Operating Income (Loss)	132	137	(104)	263
Other Income (Expenses)				
Interest expense	(70)	(65)	(137)	(130)
Other income	8	10	16	18
Total Other Expenses	(62)	(55)	(121)	(112)
Income (Loss) from Continuing Operations Before Income Tax Expense	70	82	(225)	151
Income Tax Expense Related to Continuing Operations	32	29	167	38
Net Income (Loss) from Continuing Operations	38	53	(392)	113
Income from Discontinued Operations, Net of Income Taxes	4	9	4	17
Net Income (Loss)	$ 42	$ 62	$ (388)	$ 130
Basic and Diluted Share Information				
Weighted average shares outstanding – Basic (millions)	249	228	243	228
Weighted average shares outstanding – Diluted (millions)	249	229	243	229
Earnings (Loss) per share of common stock from Continuing Operations – Basic and Diluted	$ 0.16	$ 0.23	$ (1.61)	$ 0.50
Earnings per share of common stock from Discontinued Operations – Basic and Diluted	0.01	0.04	0.01	0.07
Basic and Diluted earnings (loss) per share	$ 0.17	$ 0.27	$ (1.60)	$ 0.57

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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(millions of dollars)			
Net Income (Loss)	$ 42	$ 62	$ (388)	$ 130
Other Comprehensive Income from Continuing Operations				
Loss on treasury rate locks reclassified into income	1	—	1	—
Pension and other postretirement benefit plans	(1)	(6)	1	(5)
Other comprehensive (loss) income, before income taxes	—	(6)	2	(5)
Income tax expense (benefit) related to other comprehensive income	—	(4)	1	(3)
Other comprehensive (loss) income from continuing operations, net of income taxes	—	(2)	1	(2)
Other Comprehensive Income from Discontinued Operations, Net of Income Taxes	1	6	6	14
Comprehensive Income (Loss)	$ 43	$ 66	$ (381)	$ 142

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

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

	June 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 15	$ 25
Restricted cash equivalents	20	10
Accounts receivable, less allowance for uncollectible accounts of $37 million and $34 million, respectively	803	804
Inventories	161	153
Prepayments of income taxes	41	59
Deferred income tax assets, net	36	28
Income taxes receivable	225	69
Prepaid expenses and other	81	81
Assets held for disposition	14	38
Total Current Assets	1,396	1,267
INVESTMENTS AND OTHER ASSETS		
Goodwill	1,407	1,407
Regulatory assets	2,510	2,614
Investment in finance leases held in trust	167	1,237
Income taxes receivable	64	217
Restricted cash equivalents	15	17
Assets and accrued interest related to uncertain tax positions	9	18
Derivative assets	4	8
Other	164	163
Total Investments and Other Assets	4,340	5,681
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	14,083	13,625
Accumulated depreciation	(4,830)	(4,779)
Net Property, Plant and Equipment	9,253	8,846
TOTAL ASSETS	$ 14,989	$ 15,794

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

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

	June 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 392	$ 965
Current portion of long-term debt and project funding	756	569
Accounts payable and accrued liabilities	523	554
Capital lease obligations due within one year	9	8
Taxes accrued	50	75
Interest accrued	52	47
Liabilities and accrued interest related to uncertain tax positions	377	9
Derivative liabilities	—	4
Other	253	272
Liabilities associated with assets held for disposition	12	40
Total Current Liabilities	2,424	2,543
DEFERRED CREDITS		
Regulatory liabilities	439	501
Deferred income tax liabilities, net	2,770	3,208
Investment tax credits	19	20
Pension benefit obligation	310	449
Other postretirement benefit obligations	434	454
Liabilities and accrued interest related to uncertain tax positions	28	15
Derivative liabilities	14	11
Other	192	191
Liabilities associated with assets held for disposition	—	2
Total Deferred Credits	4,206	4,851
LONG-TERM LIABILITIES		
Long-term debt	3,811	3,648
Transition bonds issued by ACE Funding	236	256
Long-term project funding	11	12
Capital lease obligations	65	70
Total Long-Term Liabilities	4,123	3,986
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
EQUITY		
Common stock, $.01 par value, 400,000,000 shares authorized, 249,110,050 and 230,015,427 shares outstanding, respectively	2	2
Premium on stock and other capital contributions	3,720	3,383
Accumulated other comprehensive loss	(41)	(48)
Retained earnings	555	1,077
Total Equity	4,236	4,414
TOTAL LIABILITIES AND EQUITY	$ 14,989	$ 15,794

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, 2013	Six Months Ended June 30, 2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net (loss) income	$ (388)	$ 130
Income from discontinued operations	(4)	(17)
Adjustments to reconcile net (loss) income to net cash from operating activities:		
Depreciation and amortization	228	221
Non-cash rents from cross-border energy lease investments	(7)	(26)
Losses on early termination of finance leases held in trust	14	—
Non-cash charge to reduce carrying value of PHI's cross-border energy lease investments	373	—
Deferred income taxes	(451)	235
Impairment losses	—	3
Other	(8)	(8)
Changes in:		
Accounts receivable	(8)	9
Inventories	(8)	(18)
Prepaid expenses	(2)	(11)
Regulatory assets and liabilities, net	(68)	(93)
Accounts payable and accrued liabilities	(37)	(13)
Pension contributions	(120)	(200)
Pension benefit obligation, excluding contributions	32	33
Cash collateral related to derivative activities	28	53
Income tax-related prepayments, receivables and payables	614	(184)
Advanced payment made to taxing authority	(242)	—
Other assets and liabilities	22	10
Net assets held for disposition	(3)	—
Net Cash (Used By) From Operating Activities	(35)	124
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(616)	(589)
Department of Energy capital reimbursement awards received	12	22
Proceeds from early termination of finance leases held in trust	693	—
Changes in restricted cash equivalents	(8)	2
Net other investing activities	2	5
Net Cash From (Used By) Investing Activities	83	(560)
FINANCING ACTIVITIES		
Dividends paid on common stock	(134)	(123)
Common stock issued for the Dividend Reinvestment Plan and employee-related compensation	27	28
Issuances of common stock	324	—
Issuances of long-term debt	350	450
Reacquisitions of long-term debt	(19)	(122)
Repayments of short-term debt, net	(373)	(57)
Issuances of term loan	250	200
Repayments of term loan	(450)	—
Cost of issuances	(16)	(7)
Net other financing activities	(17)	(3)
Net Cash (Used by) From Financing Activities	(58)	366
Net Decrease in Cash and Cash Equivalents	(10)	(70)
Cash and Cash Equivalents at Beginning of Period	25	109
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 15	$ 39
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid (received) for income taxes, net	$ 227	$ (3)

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) Income	Retained Earnings	Total
BALANCE, DECEMBER 31, 2012	230,015,427	$ 2	$ 3,383	$ (48)	$ 1,077	$4,414
Net loss	—	—	—	—	(430)	(430)
Other comprehensive income	—	—	—	6	—	6
Dividends on common stock ($0.27 per share)	—	—	—	—	(67)	(67)
Issuance of common stock:						
Original issue shares, net	18,268,100	—	321	—	—	321
Shareholder DRP original shares	370,787	—	8	—	—	8
Net activity related to stock-based awards	(102,933)	—	(6)	—	—	(6)
BALANCE, MARCH 31, 2013	248,551,381	2	3,706	(42)	580	4,246
Net income	—	—	—	—	42	42
Other comprehensive income	—	—	—	1	—	1
Dividends on common stock ($0.27 per share)	—	—	—	—	(67)	(67)
Issuance of common stock:						
Original issue shares, net	91,424	—	2	—	—	2
Shareholder DRP original shares	364,312	—	7	—	—	7
Net activity related to stock-based awards	102,933	—	5	—	—	5
BALANCE, JUNE 30, 2013	249,110,050	$ 2	$ 3,720	$ (41)	$ 555	$4,236

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 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 (the Exchange Act). 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, high voltage underground transmission cabling, low voltage construction and maintenance services, and the design, construction and operation of combined heat and power and central energy plants. Pepco Energy Services constitutes a separate segment for financial reporting purposes.

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 a service agreement 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 agreement.

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, electricity and 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 in Delaware, the District of Columbia and Maryland, and Basic Generation Service in New Jersey. In the 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:

- providing energy savings performance contracting services principally to federal, state and local government customers, and designing, constructing and operating combined heat and power and central energy plants, and
- providing high voltage underground transmission construction and maintenance services to customers throughout the United States, as well as low voltage electric construction and maintenance services and streetlight construction services to utilities, municipalities and other customers in the Washington, D.C. metropolitan area.

During 2012, Pepco Energy Services deactivated its Buzzard Point oil-fired generation facility and its Benning Road oil-fired generation facility. Pepco Energy Services has placed the facilities into an idle condition termed a "cold closure." A cold closure requires that the utility service be disconnected so that the facilities are no longer operable and that the facilities require only essential maintenance until they are completely decommissioned.

Other Business Operations

Other Non-Regulated is a separate operating segment for financial reporting purposes and includes the portfolio of cross-border energy lease investments held through PHI's subsidiary, Potomac Capital Investment Corporation (PCI). For a discussion of the Other Non- Regulated segment, see Note (8), "Leasing Activities – Investment in Finance Leases Held in Trust," Note (11), "Income Taxes," and Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments."

In March 2013, PHI began to pursue the early termination of its remaining cross-border energy lease investments with its lessees. During July 2013, PHI completed the termination of its interest in all of its cross-border energy lease investments. With the completion of the early termination of the cross-border energy leases, substantially all of the Other Non-Regulated segment is expected to be reported as a discontinued operation in the third quarter of 2013.

Discontinued Operations

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 retail 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 retail natural gas supply businesses are being accounted for as discontinued operations and are no longer a part of the Pepco Energy Services segment for financial reporting purposes. Substantially all of the information in these notes to the consolidated financial statements with respect to Pepco Energy Services' retail energy supply business has been consolidated in Note (17), "Discontinued Operations."

(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, 2012. 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, 2013, in accordance with GAAP. The year-end December 31, 2012 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, 2013 may not be indicative of PHI's results that will be realized for the full year ending December 31, 2013.

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, 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 self-insurance reserves for general and auto liability claims, accrual of interest related to income taxes, the recognition of income tax benefits for investments in finance leases held in trust associated with PHI's portfolio of cross-border energy lease investments (see Note (8), "Leasing Activities – Investment in Finance Leases Held in Trust"), 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. Subsidiaries of PHI have the following contractual arrangements to which the guidance applies.

ACE Power Purchase Agreements

PHI, through its ACE subsidiary, is a party to three power purchase agreements (PPAs) with unaffiliated, non-utility generators (NUGs) totaling 459 megawatts (MWs). One of the agreements ends in 2016 and the other two end in 2024. Since 2004, 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 applied the scope exemption from the consolidation guidance for enterprises that have not been able to obtain such information.

Purchase activities with the NUGs, including excess power purchases not covered by the PPA, for the three months ended June 30, 2013 and 2012 were approximately $53 million and $49 million, respectively, of which approximately $48 million and $47 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs for the six months ended June 30, 2013 and 2012 were approximately $107 million and $100 million, respectively, of which approximately $103 million and $98 million, respectively, consisted of power purchases under the PPAs. The power purchase costs are recoverable from ACE's customers through regulated rates.

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, 2013, PHI, through its DPL subsidiary, is a party to three land-based wind PPAs in the aggregate amount of 128 MWs and one solar PPA with a 10 MW facility. 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 solar renewable energy credits (SRECs) from the solar facility up to certain amounts (as set forth below) at rates that are primarily fixed under the respective PPA. PHI has concluded that consolidation is not required for any of these PPAs under the FASB guidance on the consolidation of variable interest entities.

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 purchases under the three wind PPAs totaled $7 million and $6 million for the three months ended June 30, 2013 and 2012, respectively. DPL's purchases under the three wind PPAs totaled $17 million and $15 million for the six months ended June 30, 2013 and 2012, respectively.

The term of the agreement with the solar facility is 20 years and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. DPL's purchases under the solar agreement were less than $1 million for each of the three months ended June 30, 2013 and 2012, respectively. DPL's purchases under the solar agreement were less than $1 million for each of the six months ended June 30, 2013 and 2012, respectively.

On October 18, 2011, the Delaware Public Service Commission (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 (MWh) of energy produced by the fuel cell facilities over 21 years. DPL would have no liability 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, 2013 and 2012, 15 MWs and 3MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $3 million and less than $1 million to distribution customers for the three months ended June 30, 2013 and 2012, respectively. DPL billed $6 million and less than $1 million to distribution customers for the six months ended June 30, 2013 and 2012, respectively. DPL has concluded that consolidation under the variable interest entity consolidation guidance is not required for this arrangement.

Atlantic City Electric Transition Funding LLC

Atlantic City Electric Transition Funding LLC (ACE Funding) was established in 2001 by ACE solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of bonds (Transition Bonds). The proceeds of the sale of each series of Transition Bonds have been transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect non-bypassable transition bond charges (the Transition Bond Charges) from ACE customers pursuant to bondable stranded costs rate orders issued by the New Jersey Board of Public Utilities (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). ACE collects the Transition Bond Charges from its customers on behalf of ACE Funding and the holders of the Transition Bonds. 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 the Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding and PHI consolidates ACE Funding in its consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

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. The SOCAs were established under a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey. The SOCAs are 15-year, financially settled transactions approved by the NJBPU that allow generation companies to receive payments from, or require them to make payments to, ACE based on the difference between the fixed price in the SOCAs and the price for capacity that clears PJM Interconnection, LLC (PJM). Each of the other electric distribution companies (EDCs) in New Jersey has entered into SOCAs having the same terms with the same generation companies. ACE's share of the payments received from or the payments made to the generation companies is currently estimated to be approximately 15 percent, based on its proportionate share of the total New Jersey electric load for all EDCs. The NJBPU has ordered that ACE is obligated to distribute to its distribution customers all payments it receives from the generation companies and may recover from its distribution customers all payments it makes to the generation companies. For additional discussion about the SOCAs, see Note (7), "Regulatory Matters."

In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. For each SOCA that clears the capacity auction, ACE records a derivative asset (liability) for the estimated fair value of that SOCA and records an offsetting regulatory liability (asset) as described in more detail in Note (13), "Derivative Instruments and Hedging Activities," and Note (14), "Fair Value Disclosures." Effective July 1, 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. PHI has concluded that consolidation of the generation companies is not required.

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. Substantially all of Pepco Holdings' goodwill was generated by Pepco's acquisition of Conectiv (now Conectiv, LLC (Conectiv)) in 2002 and is allocated entirely to Power Delivery for purposes of impairment testing based on the aggregation of its components because its utilities have similar characteristics. Pepco Holdings 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 reduce the 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 below book value; an adverse regulatory action; or an impairment of long-lived assets in the reporting unit. PHI concluded that an interim impairment test was not required during the six months ended June 30, 2013.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco Holdings' gross revenues were $83 million and $87 million for the three months ended June 30, 2013 and 2012, respectively. Taxes included in Pepco Holdings' gross revenues were $166 million and $174 million for the six months ended June 30, 2013 and 2012, respectively.

Reclassifications and Adjustments

Certain prior period amounts have been reclassified in order to conform to the current period presentation. The following reclassifications and adjustments have been recorded and are not considered material either individually or in the aggregate:

DPL Operating Revenue Adjustment

In the second quarter of 2012, DPL recorded an adjustment to correct an overstatement of unbilled revenue in its natural gas distribution business related to prior periods. The adjustment resulted in a decrease in Operating Revenue of $1 million for the three and six months ended June 30, 2012.

Income Tax Expense Adjustments

In the second quarter of 2012, Pepco recorded an adjustment to reduce Income Tax expense as a result of the reversal of interest expense erroneously recorded on certain effectively settled income tax positions in the first quarter of 2012. This adjustment resulted in a decrease to Income Tax expense of $1 million for the three months ended June 30, 2012.

Revision to Prior Period 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 an adjustment related to prior periods. PHI determined that the cumulative adjustment required for the periods prior to 2008 (2008 representing the earliest year for which selected consolidated financial data were presented in Part II, Item 6. "Selected Financial Data" included in PHI's 2012 Form 10-K) was a charge to earnings of $32 million. 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 for the three and six months ended June 30, 2013, as well as estimated full year 2013 results, if corrected in 2013. As a result, PHI has revised its prior period financial statements to correct for this error, and the table below illustrates the effects of this revision on PHI's consolidated balance sheets as of March 31, 2013 and December 31, 2012, 2011, 2010 and 2009 for those line items affected (these revisions have no impact on PHI's consolidated statements of income (loss), comprehensive income (loss), and cash flows for the periods reported in these consolidated financial statements).

	As Filed	Adjustment (millions of dollars)	As Revised
March 31, 2013			
Deferred income tax liabilities, net	$ 2,685	$ 32	$ 2,717
Total deferred credits	4,270	32	4,302
Retained earnings	612	(32)	580
Total equity	4,278	(32)	4,246
December 31, 2012			
Deferred income tax liabilities, net	$ 3,176	$ 32	$ 3,208
Total deferred credits	4,819 (a)	32	4,851
Retained earnings	1,109	(32)	1,077
Total equity	4,446	(32)	4,414
December 31, 2011			
Deferred income tax liabilities, net	$ 2,863	$ 32	$ 2,895
Total deferred credits	4,533	32	4,565
Retained earnings	1,072	(32)	1,040
Total equity	4,336	(32)	4,304
December 31, 2010			
Retained earnings	$ 1,059	$ (32)	$ 1,027

December 31, 2009			
Retained earnings	$ 1,268	$ (32)	$ 1,236

(a) The amount of total deferred credits differs from the amount reported in PHI's 2012 Form 10-K due to certain reclassifications.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and financial liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosure requirements include information about the gross exposure of the instruments and the net exposure of the instruments under contractual netting arrangements, how the exposures are presented in the financial statements, and the terms and conditions of the contractual netting arrangements. PHI adopted the new guidance during the first quarter of 2013 and concluded it did not have a material impact on its consolidated financial statements.

Comprehensive Income (ASC 220)

The new disclosure requirements for reclassifications from accumulated other comprehensive income were effective for PHI beginning with its March 31, 2013 consolidated financial statements and required PHI to present additional information about its reclassifications from accumulated other comprehensive income in a single footnote or on the face of its consolidated financial statements. The additional information required to be disclosed includes a presentation of the components of accumulated other comprehensive income that have been reclassified by source (e.g., commodity derivatives), and the income statement line item (e.g., Fuel and Purchased Energy) affected by the reclassification. PHI has provided the new required disclosures in Note (16), "Accumulated Other Comprehensive Loss."

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (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 will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. PHI will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between PHI and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. PHI is evaluating the impact of this new guidance on its consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the 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 new requirements are effective prospectively beginning with PHI's March 31, 2014 consolidated financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. PHI is currently evaluating the impact of this new guidance on its consolidated financial statements.

(5) SEGMENT INFORMATION

Pepco Holdings' management has identified its operating segments at June 30, 2013 as Power Delivery, Pepco Energy Services and Other Non-Regulated. 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. Segment financial information for continuing operations for the three and six months ended June 30, 2013 and 2012 is as follows:

	Three Months Ended June 30, 2013 *(millions of dollars)*				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 1,006	$ 49	$ 3	$ (5)	$ 1,053
Operating Expenses (b)	866	47	18	(10)	921
Operating Income (Loss)	140	2	(15)	5	132
Interest Income	—	—	1	(1)	—
Interest Expense	58	—	—	12	70
Other Income	7	—	—	1	8
Income Tax Expense (Benefit)	33	1	1	(3)	32
Net Income (Loss) from Continuing Operations	56	1	(15)	(4)	38
Total Assets (excluding Assets Held for Disposition)	12,535	350	765	1,325	14,975
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 the Corporate and Other segment 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, $(5) million for Operating Expenses and $(2) million for Interest Income.

(b) Includes depreciation and amortization expense of $116 million, consisting of $107 million for Power Delivery, $2 million for Pepco Energy Services, $1 million for Other Non-Regulated and $6 million for Corporate and Other.

	Three Months Ended June 30, 2012 (millions of dollars)				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 984	$ 76	$ 14	$ (4)	$ 1,070
Operating Expenses (b)	860	77(c)	2	(6)	933
Operating Income (Loss)	124	(1)	12	2	137
Interest Income	—	—	1	(1)	—
Interest Expense	53	—	4	8	65
Other Income	8	—	—	2	10
Income Tax Expense	25	—	2	2	29
Net Income (Loss) from Continuing Operations	54	(1)	7	(7)	53
Total Assets (excluding Assets Held for Disposition)	11,734	480	1,499	1,652	15,365
Construction Expenditures	$ 285	$ 5	$ —	$ 8	$ 298

(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 the Corporate and Other segment 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, $(1) million for Operating Expenses, $(6) million for Interest Income and $(5) million for Interest Expense.

(b) Includes depreciation and amortization expense of $111 million, consisting of $100 million for Power Delivery, $4 million for Pepco Energy Services and $7 million for Corporate and Other.

(c) Includes impairment losses of $3 million associated primarily with Pepco Energy Services' investment in a landfill gas-fired electric generation facility.

	Six Months Ended June 30, 2013 (millions of dollars)				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 2,130	$ 106	$ (365)(b)	$ (6)	$ 1,865
Operating Expenses (c)	1,867	101	18	(17)	1,969
Operating Income (Loss)	263	5	(383)	11	(104)
Interest Income	—	—	2	(2)	—
Interest Expense	114	—	1	22	137
Other Income	13	1	1	1	16
Preferred Stock Dividends	—	—	1	(1)	—
Income Tax Expense (d)	48	2	54(e)	63	167
Net Income (Loss) from Continuing Operations	114	4	(436)	(74)	(392)
Total Assets (excluding Assets Held for Disposition)	12,535	350	765	1,325	14,975
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 the Corporate and Other segment and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(6) million for Operating Revenue, $(6) million for Operating Expenses, $(5) million for Interest Income, $(4) million for Interest Expense and $(1) million for Preferred Stock Dividends.

(b) Includes a non-cash pre-tax charge of $373 million to reduce the carrying value of the cross-border energy lease investments.

(c) Includes depreciation and amortization expense of $228 million, consisting of $211 million for Power Delivery, $4 million for Pepco Energy Services, $1 million for Other Non-Regulated and $12 million for Corporate and Other.

(d) 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 $16 million and $66 million for Other Non-Regulated and Corporate and Other, respectively.

(e) Includes non-cash charges of $64 million primarily for the tax consequences associated with PHI's change in intent regarding foreign investment opportunities associated with the cross-border energy lease investments and $101 million representing the establishment of valuation allowances against certain deferred tax assets of PCI included in Other Non-Regulated.

	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
	Six Months Ended June 30, 2012 (millions of dollars)				
Operating Revenue	$ 2,039	$ 148	$ 27	$ (8)	$ 2,206
Operating Expenses (b)	1,814	145(c)	3	(19)	1,943
Operating Income	225	3	24	11	263
Interest Income	—	—	2	(2)	—
Interest Expense	106	1	7	16	130
Other Income	16	—	1	1	18
Preferred Stock Dividends	—	—	1	(1)	—
Income Tax Expense	34	1	2	1	38
Net Income (Loss) from Continuing Operations	101	1	17	(6)	113
Total Assets (excluding Assets Held for Disposition)	11,734	480	1,499	1,652	15,365
Construction Expenditures	$ 565	$ 10	$ —	$ 14	$ 589

(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 the Corporate and Other segment and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(8) million for Operating Revenue, $(7) million for Operating Expenses, $(11) million for Interest Income, $(10) million for Interest Expense and $(1) million for Preferred Stock Dividends.

(b) Includes depreciation and amortization expense of $221 million, consisting of $199 million for Power Delivery, $10 million for Pepco Energy Services, $1 million for Other Non-Regulated and $11 million for Corporate and Other.

(c) Includes impairment losses of $3 million associated primarily with Pepco Energy Services' investment in a landfill gas-fired electric generation facility.

(6) GOODWILL

PHI's goodwill balance of $1.4 billion was unchanged during the six months ended June 30, 2013. Substantially all of PHI's goodwill balance was generated by Pepco's acquisition of 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, 2012 indicated that goodwill was not impaired. For the six months ended June 30, 2013, PHI concluded that there were no events requiring it to perform an interim goodwill impairment test. PHI will perform its next annual impairment test as of November 1, 2013.

(7) REGULATORY MATTERS

Rate Proceedings

Over the last several years, 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) was approved and implemented for Pepco and DPL electric service in Maryland and for Pepco electric service in the District of Columbia.
- A modified fixed variable rate design (MFVRD) for DPL electric and natural gas service in Delaware is under consideration by the DPSC.
- 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 under consideration by the DPSC in Delaware provides for 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. Although different from the BSA, PHI views the MFVRD as an appropriate distribution revenue decoupling mechanism.

The following table shows, for each of the PHI utility subsidiaries, the base rate cases currently pending. More information concerning each of these filings 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
DE – DPL Gas	$ 12.0(a)	10.25%	December 7, 2012	Q4-2013
DC – Pepco Electric	52.1	10.25%	March 8, 2013	Q1-2014
DE – DPL Electric	42.0	10.25%	March 22, 2013	Q1-2014
MD – DPL Electric	22.8	10.25%	March 29, 2013	Q3-2013(b)

(a) Reflects DPL's updated revenue requirement as filed on July 15, 2013.
(b) On July 17, 2013, a joint motion was filed by the parties requesting MPSC approval of a settlement providing for an annual rate increase of $15 million (an imputed ROE of 9.81%) (see below under "Maryland – DPL Electric Distribution Base Rates").

The following table shows, for each of the PHI utility subsidiaries, the base rate cases completed in 2013. More 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
NJ – ACE Electric	$ 25.5	9.75%	June 21, 2013	July 1, 2013
MD – Pepco Electric	27.8	9.36%	July 12, 2013	July 12, 2013

<u>Delaware</u>

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. In August 2012, DPL made its 2012 GCR filing. The rates proposed in the 2012 GCR would result in a GCR decrease of approximately 22.3%. On September 18, 2012, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2012, subject to refund and pending final DPSC approval. On June 18, 2013, the DPSC issued an order approving a settlement agreement entered into on April 24, 2013 by DPL and the DPSC staff. This order provided that the proposed GCR rates as filed by DPL be approved.

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $42 million, based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with DPL's ongoing 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. A final DPSC decision is expected by the first quarter of 2014.

Gas Distribution Base Rates

On December 7, 2012, DPL submitted an application with the DPSC to increase its natural gas distribution base rates. The filing seeks approval of an annual rate increase of approximately $12.0 million (as adjusted on July 15, 2013), based on a requested ROE of 10.25%. The requested rate increase is for the purposes of recovering expenses associated with DPL's ongoing efforts to maintain safe and reliable service and to provide enhanced customer service technology. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on February 5, 2013, subject to refund and pending final DPSC approval. On July 2, 2013, the DPSC approved DPL's request to implement an additional interim increase of $8 million on July 7, 2013, as permitted by state law. A final DPSC decision is expected by the fourth quarter of 2013.

District of Columbia

On March 8, 2013, Pepco filed an application with the District of Columbia Public Service Commission (DCPSC) to increase its electric distribution base rates by approximately $52.1 million annually, based on a requested ROE of 10.25%. The requested rate increase is for the purpose of recovering (i) Pepco's expenses associated with ongoing efforts to maintain safe and reliable service for its customers, (ii) Pepco's investment in infrastructure to maintain and harden the electric distribution system, and (iii) Pepco's investment in major reliability enhancement improvements. Evidentiary hearings are expected to begin on November 4, 2013 and a final DCPSC decision is expected in the first quarter of 2014.

Maryland

DPL Electric Distribution Base Rates

On March 29, 2013, DPL submitted an application with the Maryland Public Service Commission (MPSC) to increase its electric distribution base rates by approximately $22.8 million, based on a requested ROE of 10.25%. The requested rate increase was for the purpose of recovering reliability enhancements to serve Maryland customers. DPL also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $10.2 million associated with its plan to accelerate investments in electric distribution 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 (as discussed below under "Reliability Task Forces"). Specific projects under DPL's Grid Resiliency Charge plan included accelerating its tree-trimming cycle and upgrading five additional feeders per year for two years. In addition, DPL proposed a reliability performance-based mechanism that would allow DPL to earn up to $500,000 as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $500,000 in total if DPL does not meet at least the minimum reliability performance targets. DPL requested that any credits or charges would flow through the proposed Grid Resiliency Charge rider.

On July 17, 2013, DPL, the MPSC staff and the Maryland Office of People's Counsel (OPC) filed a joint motion with the MPSC, requesting that the MPSC approve a settlement entered into by the parties. The settlement provides for an annual rate increase of $15 million (an imputed ROE of 9.81%). The settlement provides for 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 amortizing the related deferred operation and maintenance expenses of approximately $6 million over a five-year period with the unamortized balance included in rate base. The settlement also provides for a Grid Resiliency Charge for recovery of costs totaling approximately $4.2 million associated with DPL's proposed plan to accelerate investments related to certain priority feeders, provided that DPL provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The settlement does not provide for approval of a portion of the Grid Resiliency Charge related to the proposed acceleration of the tree-trimming cycle, or DPL's proposed reliability performance-based mechanism. Under the settlement, the new rates would become effective on September 15, 2013 or as soon as reasonably practicable thereafter following effectiveness of the proposed MPSC order, which will occur on August 30, 2013 unless challenged by a party to the proceeding or the MPSC modifies or reverses the proposed order or initiates further proceedings in the matter.

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 reduced by Pepco to $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%. The order also reduced Pepco's depreciation rates, which lowered annual depreciation and amortization expenses by an estimated $27.3 million. The lower depreciation rates resulted from, among other things, the rebalancing of excess reserves for estimated future removal costs identified in a depreciation study conducted as part of the rate case filing. The identified excess reserves for estimated future removal costs, reported as Regulatory Liabilities, were reclassified to Accumulated Depreciation among various plant accounts. Among other things, the order also authorizes Pepco to recover the actual cost of advanced metering infrastructure (AMI) meters installed during the 2011 test year and states that cost recovery for AMI deployment will only be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. The Maryland 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 was for the purpose of recovering reliability enhancements to serve Maryland customers. 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 (as discussed below under "Reliability Task Forces"). 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 $27.8 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 requires that the cost of AMI meters be excluded from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system; however, the July 2012 MPSC ruling in Pepco's previous electric distribution base rate case, which stated that Pepco may recover the costs of meters installed during the 2011 test year for that case, is not affected by the July 2013 order and the Maryland OPC's motion for rehearing in that case remains pending. As a result, costs for AMI meters will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system which are deferred and on which a return is earned. The order also approved a Grid Resiliency Charge 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 Pepco provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The MPSC did not approve the proposed acceleration of the tree-trimming cycle or the undergrounding of six distribution feeders. The MPSC 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 this July 12, 2013 order in the Circuit Court for the City of Baltimore. Pepco intends to file another electric distribution base rate case with the MPSC in the fourth quarter of 2013. Pepco is continuing to review the impact of the order and may also consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to the utility.

New Jersey

Electric Distribution Base Rates

On December 11, 2012, ACE submitted an application with the NJBPU, updated on January 4, 2013, to increase its electric distribution base rates by approximately $70.4 million (excluding sales-and-use taxes), based on a requested ROE of 10.25%. This proposed net increase was comprised of (i) a proposed increase to ACE's distribution rates of approximately $72.1 million and (ii) a net decrease to ACE's Regulatory Asset Recovery Charge (RARC) (costs associated with deferred, NJBPU-approved expenses incurred as part of ACE's public service obligation) in the amount of approximately $1.7 million. The requested rate increase was primarily for the purposes of continuing to implement reliability-related investments and recovering system restoration costs associated with the derecho storm in June 2012 and Hurricane Sandy in October 2012. On June 21, 2013, the NJBPU approved a settlement of the parties (the "NJ Rate Settlement") providing for an increase in ACE's distribution base rates in the amount of $25.5 million, based on an ROE of 9.75%. The base distribution revenue increase includes full recovery of the approximately $70.0 million in incremental storm restoration costs incurred as a result of recent major storm events, including the derecho storm and Hurricane Sandy, by including the related capital costs of approximately $44.2 million in rate base and amortizing the related deferred operation and maintenance expenses of approximately $25.8 million over a three-year period. In addition, depreciation expense will be reduced approximately $8.3 million per year. The NJ Rate Settlement also includes approximately $4.9 million of current RARC, but eliminates the RARC going forward. Rates were effective on July 1, 2013.

In a March 20, 2013 order, the NJBPU established a generic proceeding to evaluate the prudency of major storm event restoration costs and expenses. Each New Jersey EDC was directed to file a separate proceeding for the evaluation of these costs. Those portions of ACE's electric base rate filing pertaining to the recovery of major storm event expenditures were to be evaluated in the context of the generic proceeding. On April 9, 2013, ACE filed a petition with the NJBPU to comply with the NJBPU's generic storm cost order. All other issues in ACE's base rate filing remained unchanged in the electric base rate proceeding discussed above. In its order approving the NJ Rate Settlement, the NJBPU found that (i) ACE's April 9, 2013 petition met all the requirements of the NJBPU's March 20, 2013 order, and (ii) the major storm event costs for the June 2012 derecho storm and Hurricane Sandy may be recovered in ACE's electric distribution base rate case, discussed above.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012, 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 NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program for low income customers) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the projected deferred under-recovered balance related to the NUGs of $113.8 million as of May 31, 2012 through a four-year amortization schedule. In June 2012, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on July 1, 2012. The net impact of adjusting the charges (consisting of both the annual impact of the proposed four-year amortization of the historical under-recovered NUG balances of $127.0 million as of June 30, 2012 and the going-forward cost recovery of all the other charges for the period July 1, 2012 through May 31, 2013, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $55.3 million. The rates were deemed "provisional" because ACE's filing was not updated for actual revenues and expenses for May and June 2012 until the March 5, 2013 petition described below was filed, after which a review by the NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the New Jersey Office of Administrative Law (OAL) for possible hearing.

On March 5, 2013, ACE submitted a new 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 NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the forecasted above-market NUG costs of approximately $67.9 million for the period June 1, 2013 through May 31, 2014, the projected deferred under-recovered balance related to the NUGs of approximately $40.8 million as of May 31, 2013, and an additional approximately $32.9 million associated with the deferred under-recovered balance that is being amortized over a four-year amortization period. In May 2013, NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on June 1, 2013.The net impact of adjusting the charges updated for actual data through March 31, 2013 (consisting of both the second year impact of the stipulated four-year amortization of the historical under-recovered NUG balances and the going-forward cost recovery of all the other charges for the period June 1, 2013 through May 31, 2014, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $52.2 million (this rate increase is in addition to the approximately $55.3 million approved by the NJBPU in June 2012, as discussed in the above paragraph). The rates were deemed "provisional" because ACE's filing was not updated for actual revenues and expenses for April and May 2013. A review by NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the OAL for possible hearing.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland 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 MW beginning in 2015. The order requires Pepco, DPL and Baltimore Gas and Electric Company (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 the Contract EDCs will recover the associated costs through surcharges on their 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. These circuit court appeals were consolidated in the Circuit Court for Baltimore City and stayed pending the issuance of a final order from the MPSC approving the form of contract.

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, in amounts proportional to their relative SOS loads, with the winning bidder. The MPSC stated that the order, which approves timely and complete recovery by the Contract EDCs of the costs associated with the contract, constitutes a binding commitment that shall not be subject to future modification or rescission by the MPSC. Despite this commitment from the MPSC, Pepco and DPL believe that the attempt by the MPSC to bind a future commission in this manner may be subject to legal challenge, which challenge, if successful, could impair the right of Pepco and DPL to recover their costs in the future. In addition, the MPSC excluded from the contract a provision that Pepco and DPL believe is important to mitigate their financial risk because the provision, had it been included, would have required Pepco and DPL to make payments to the winning bidder under the contract only to the extent they were able to recover those costs (for example, Pepco and DPL believe the excluded provision would have protected them in the event a significant number of their SOS customers elect to buy their energy from alternative energy suppliers). In light of the issuance of the MPSC's final order, the previously filed appeals of the MPSC's actions in this case before the circuit court are now proceeding. On June 4, 2013, Pepco and DPL entered into the contract in accordance with the terms of the MPSC's order; however, under the contract's own terms, it will not become effective, if at all, until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

PHI believes that Pepco and DPL may be required to account for their proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because they would recover any payments under the contract from SOS customers. Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, PHI estimates that Pepco and DPL would be required to record an aggregate derivative liability ranging from $55 million to $70 million with an offsetting regulatory asset in a like amount. These estimates and other assumptions made may change prior to the time that the contract becomes effective, if at all. PHI, Pepco and DPL have concluded that any accounting for this contract would not be required until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

PHI, Pepco and DPL are in the process of determining (i) the extent of the negative effect that the contract for new generation 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 each of their debt issuances, (ii) the effect on Pepco's and DPL's ability to recover their associated costs of the contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

Reliability Task Forces

In July 2012, the Maryland governor signed an Executive Order directing his energy advisor, in collaboration with certain state agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the electric distribution system in Maryland. The resulting Grid Resiliency Task Force issued its report in September 2012, in which it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. Pepco's electric distribution base rate case filed with the MPSC on November 30, 2012 and DPL's electric distribution base rate case filed with the MPSC on March 29, 2013, each attempted to address the Grid Resiliency Task Force recommendations.

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. The options that are available for financing these efforts were also to be evaluated to identify required legislative or regulatory actions to implement these recommendations. On May 13, 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan of the DC Undergrounding Task Force to bury five dozen of the District of Columbia's most outage-prone power lines. Under this recommendation, (i) Pepco would bear approximately $500 million of the $1 billion estimated cost to complete this project, recovering those costs through surcharges on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the undergrounding project cost would be financed by the District of Columbia's issuance of municipal bonds, which bonds would be repaid through surcharges on the electric bills of Pepco District of Columbia customers (Pepco would not earn a return on the underground lines paid for with the proceeds received from the issuance of the bonds, but those lines would be transferred to Pepco to operate and maintain); and (iii) the remaining amount would be funded through the District of Columbia Department of Transportation's existing capital projects program. Legislation providing for implementation of the report recommendations was introduced in the Council of the District of Columbia on July 10, 2013. This legislation is expected to be voted upon by the City Council by the fourth quarter of 2013. The final step in the process would be DCPSC approval of the recommendations, a decision on which is expected by the first quarter of 2014.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three SOCAs by order of the NJBPU, each with a different generation company, as more fully described in Note (2), "Significant Accounting Policies – Consolidation of Variable Interest Entities – ACE Standard Offer Capacity Agreements" and Note (13), "Derivative Instruments and Hedging Activities." 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 dispute is pending before the NJBPU and has been referred to an Administrative Law Judge for further consideration. On April 11, 2013, the Superior Court of New Jersey Appellate Division issued an order consolidating the EDCs' state court appeal of the NJBPU order (filed by the EDCs with the Appellate Division of the New Jersey Superior Court in June 2011) with a similar challenge filed by several generators and instructing the Administrative Law Judge to complete proceedings by June 15, 2013. The NJBPU filed a motion for clarification of the Appellate Division order, seeking an extension of time to complete the proceedings at the OAL. On June 28, 2013, the Appellate Division issued an order staying the consolidated appeals until September 30, 2013, and requiring the proceedings before the OAL and the NJBPU to be completed by that time.

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 New Jersey law under which the SOCAs were established on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In September 2012, the District Court denied motions for summary judgment filed by ACE and the other plaintiffs, as well as cross-motions filed by defendants. A bench trial was completed in May 2013 and final arguments were heard by the District Court Judge on June 17, 2013. It has not been determined when the District Court will issue 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.

MAPP Project

On August 24, 2012, the board of PJM terminated the Mid-Atlantic Power Pathway (MAPP) project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. As of December 31, 2012, PHI's total costs related to the MAPP project were $102 million. In a 2008 FERC order approving incentives for the MAPP project, FERC authorized the recovery of prudently incurred abandoned costs in connection with the MAPP project. Consistent with this order, in December 2012, PHI submitted a filing to FERC seeking recovery of $88 million of abandoned MAPP costs. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

Various protests were submitted in response to PHI's December 2012 filing, arguing, among other things, that FERC should disallow a portion of the rate of return involving an incentive adder that would be applied to the abandoned costs, and requesting a hearing on various issues such as the amount of the ROE and the prudence of the costs. On February 28, 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by PHI to be $2 million), of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. PHI believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. On April 1, 2013, PHI filed a rehearing request of the February 28, 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that PHI is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. PHI cannot predict when a final FERC decision in this proceeding will be issued.

As of December 31, 2012, PHI had placed in service $11 million of its total capital expenditures with respect to the MAPP project, which represented upgrades of existing substation assets that were expected to support the MAPP transmission line, transferred approximately $3 million of materials to inventories, for use on other projects, and reclassified the remaining $88 million of capital expenditures to a regulatory asset. During the first quarter of 2013, PHI further transferred an additional $2 million of materials to inventories, for use on other projects, and expensed $2 million of abandoned costs as a result of FERC's disallowance noted above. During the second quarter of 2013, PHI further transferred an additional $3 million of materials to inventories, for use on other projects, resulting in a regulatory asset of $81 million as of June 30, 2013. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. PHI intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

Transmission ROE Challenge

On February 27, 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, 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 claim to 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. On April 3, 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.

(8) LEASING ACTIVITIES

Investment in Finance Leases Held in Trust

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. As of June 30, 2013 and December 31, 2012, the lease portfolio consisted of one investment and six investments, respectively, with a net investment value of $167 million and $1,237 million, respectively.

In March 2013, PHI began to pursue the early termination of all of its remaining cross-border energy lease investments with its lessees. During the second quarter of 2013, PHI terminated early its interest in five of the six remaining lease investments. PHI received aggregate net cash proceeds of $693 million (net of aggregate termination payments of $1.4 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 $14 million ($9 million after-tax) in the second quarter of 2013, representing the excess of the carrying value of the terminated leases over the net cash proceeds received.

During July 2013, PHI entered into an agreement with the lessee of the last remaining PHI lease investment which provides for the early termination of such lease investment. Upon closing, on July 26, 2013, PHI received aggregate net cash proceeds of $180 million (net of aggregate termination payments of $665 million used to retire the non-recourse debt associated with the terminated leases) and expects to record in the third quarter of 2013 a pre-tax gain, including transaction costs, of approximately $11 million ($7 million after-tax), representing the excess of the net cash proceeds received over the carrying value of the terminated leases. After consideration of this final termination, the aggregate financial impact upon completion of the early terminations of the cross-border energy leases is expected to be a pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax) for the year ending December 31, 2013.

The components of the cross-border energy lease investments as of June 30, 2013 and December 31, 2012 are summarized below:

	June 30, 2013	December 31, 2012
	(millions of dollars)	
Scheduled lease payments to PHI, net of non-recourse debt	$ 223	$ 1,852
Less: Unearned and deferred income	(56)	(615)
Investment in finance leases held in trust	167	1,237
Less: Deferred income tax liabilities	(83)	(756)
Net investment in finance leases held in trust	$ 84	$ 481

Income recognized from cross-border energy lease investments, excluding the losses on terminated leases discussed above, was comprised of the following for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Pre-tax income from PHI's cross-border energy lease investments (included in Other Revenue)	$ 2	$ 13	$ 7	$ 26
Non-cash charge to reduce carrying value of PHI's cross-border energy lease investments	—	—	(373)	—
Pre-tax income (loss) from PHI's cross-border energy lease investments after adjustment	2	13	(366)	26
Income tax expense (benefit) related to PHI's cross-border energy lease investments	6	3	(43)(a)	4
Net (loss) income from PHI's cross-border energy lease investments	$ (4)	$ 10	$(323)	$ 22

(a) Includes a charge of $64 million for the tax consequences associated with PHI's change in intent regarding foreign investment opportunities and interest expense on uncertain tax positions of $16 million, each recorded in the first quarter of 2013.

PHI is required to assess on a periodic basis the likely outcome of tax positions relating to its cross-border energy lease investments and, if there is a change or a projected change in the timing of the estimated tax benefits generated by the transactions, PHI is required to recalculate the value of its net investment.

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 has determined that its tax position with respect to the benefits associated with its cross-border energy leases no longer meets the more-likely-than-not standard of recognition for accounting purposes, and PHI recorded an after-tax non-cash charge of $377 million in the first quarter of 2013, consisting of the following components:

- A non-cash pre-tax charge of $373 million ($307 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 has been recorded in the consolidated statement of income as a reduction in Other Operating revenue.
- A non-cash charge of $70 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 has been recorded in the consolidated statement of income as an increase in income tax expense and 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 and $66 million for the Other Non-Regulated and Corporate and Other segments, 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 has concluded that these business assumptions are no longer supportable and the tax effects of this conclusion are reflected in the after-tax charge of $307 million described above.

PHI has 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 Internal Revenue Service (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."

To ensure credit quality, PHI regularly monitors the financial performance and condition of the lessees under its cross-border energy lease investments. Changes in credit quality are also assessed to determine if they should be reflected in the carrying value of the leases. PHI compares each lessee's performance to annual compliance requirements set by the terms and conditions of the leases. This includes a comparison of published credit ratings to minimum credit rating requirements in the leases for lessees with public credit ratings. In addition, PHI routinely meets with senior executives of the lessees to discuss their company and asset performance. If the annual compliance requirements or minimum credit ratings are not met, remedies are available under the leases. At June 30, 2013, all lessees were in compliance with the terms and conditions of their lease agreements.

The table below shows PHI's net investment in these leases by the published credit ratings of the lessees as of June 30, 2013 and December 31, 2012:

Lessee Rating (a)	**June 30, 2013**	**December 31, 2012**
	(millions of dollars)	
Rated Entities		
AA/Aa and above	$ 167	$ 766
A	—	471
Total	$ 167	$ 1,237

(a) Excludes the credit ratings associated with collateral posted by the lessees in these transactions.

(9) PENSION AND OTHER POSTRETIREMENT BENEFITS

The following Pepco Holdings information is for the three months ended June 30, 2013 and 2012:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Service cost	$ 13	$ 7	$ 2	$ 3
Interest cost	25	27	8	8
Expected return on plan assets	(36)	(32)	(5)	(4)
Amortization of prior service cost (benefit)	1	1	(1)	(1)
Amortization of net actuarial loss	18	18	4	2
Termination benefits	—	—	—	1
Net periodic benefit cost	$ 21	$ 21	$ 8	$ 9

The following Pepco Holdings information is for the six months ended June 30, 2013 and 2012:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Service cost	$ 26	$ 18	$ 4	$ 4
Interest cost	50	53	16	17
Expected return on plan assets	(73)	(66)	(10)	(9)
Amortization of prior service cost (benefit)	1	1	(2)	(2)
Amortization of net actuarial loss	34	32	8	7
Termination benefits	—	—	—	1
Net periodic benefit cost	$ 38	$ 38	$ 16	$ 18

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. After intercompany allocations, the three utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and other postretirement benefit costs related to continuing operations.

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 the second quarter of 2013, PHI made a discretionary tax-deductible contribution to the PHI Retirement Plan in the amount of $60 million. In the first quarter of 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $20 million, $10 million and $30 million, respectively. In the first quarter of 2012, Pepco, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $85 million, $85 million and $30 million, respectively, which brought the PHI Retirement Plan assets to the funding target level for 2012 under the Pension Protection Act.

Other Postretirement Benefit Plan Amendment

In July 2013, PHI approved an amendment to its retiree medical plans that will be effective on January 1, 2014. As a result of the amendment, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013 and recorded a prior service credit of approximately $100 million, which will be amortized over approximately ten years. The remeasurement is expected to result in a $13 million reduction in net periodic benefit cost for other postretirement benefits to be recognized in the second half of 2013 as compared to the net periodic benefit cost for other postretirement benefits recognized in the first half of 2013.

(10) 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. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

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, 2013.

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, 2013 and December 31, 2012, 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 $1,230 million and $861 million, respectively. PHI's utility subsidiaries had combined cash and unused borrowing capacity under the credit facility of $595 million and $477 million at June 30, 2013 and December 31, 2012, respectively.

Commercial Paper

PHI, Pepco, DPL and ACE maintain on-going commercial paper programs to address short-term liquidity needs. As of June 30, 2013, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $250 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, DPL and ACE had $114 million, $109 million and $46 million, respectively, of commercial paper outstanding at June 30, 2013. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2013 was 0.71%, 0.38%, 0.32% and 0.34%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2013 was five, seven, two 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 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.

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, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.95%, 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, 2013.

Bond Payments

In April 2013, 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 Redemptions

On May 30, 2013, ACE redeemed, prior to maturity, at par plus accrued interest, all $4.4 million outstanding weekly rate pollution control revenue refunding bonds due 2017, issued by the Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit.

Financing Activities Subsequent to June 30, 2013

Bond Payments

In July 2013, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

(11) INCOME TAXES

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 25	35.0%	$ 29	35.0%	$ (79)	35.0%	$ 53	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	6	8.6%	5	6.1%	10	(4.4)%	10	6.6%
Asset removal costs	(3)	(4.3)%	(4)	(4.9)%	(6)	2.7%	(7)	(4.6)%
Change in estimates and interest related to uncertain and effectively settled tax positions	3	4.3%	3	3.7%	70	(31.1)%	(10)	(6.6)%
Cross-border energy lease investments	6	8.6%	(1)	(1.2)%	70	(31.1)%	(2)	(1.3)%
Establishment of valuation allowances related to deferred tax assets	—	—	—	—	101	(44.9)%	—	—
Other, net	(5)	(6.5)%	(3)	(3.3)%	1	(0.4)%	(6)	(3.9)%
Consolidated income tax expense related to continuing operations	$ 32	45.7%	$ 29	35.4%	$167	(74.2)%	$ 38	25.2%

Three Months Ended June 30, 2013 and 2012

PHI's consolidated effective tax rates for the three months ended June 30, 2013 and 2012 were 45.7% and 35.4%, respectively. The increase in the effective tax rate primarily resulted from a charge of $6 million in the second quarter of 2013 to reflect a change in estimate associated with state income taxes related to the reduction of the carrying value of PCI's cross-border energy lease investments recorded in the first quarter of 2013.

Six Months Ended June 30, 2013 and 2012

PHI's consolidated effective tax rates for the six months ended June 30, 2013 and 2012 were (74.2)% and 25.2%, respectively.

The negative effective tax rate for the six months ended June 30, 2013 occurred as a result of recording $70 million of changes in estimates and interest related to uncertain and effectively settled tax positions, primarily associated with the cross-border energy lease investments (as further discussed in Note (8), "Leasing Activities") and the recognition of a $64 million charge primarily for the tax consequences associated with PHI's change in intent regarding foreign investment opportunities available at the end of the full lease terms of the cross-border energy lease investments.

The negative effective tax rate further resulted from the establishment of valuation allowances of $101 million in the first quarter of 2013 against certain deferred tax assets in PHI's Other Non-Regulated segment. 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 both Consolidated Edison's cross-border lease transaction (as discussed in Note (8), "Leasing Activities") and another taxpayer's structured transactions, (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 represents 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 will 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.

In 2012, PHI's effective tax rate was impacted by the effective settlement with the IRS in the first quarter of 2012 with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position in Pepco.

(12) 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,	
	2013	2012
	(millions of dollars, except per share data)	
Income (Numerator):		
Net Income from continuing operations	$ 38	$ 53
Net Income from discontinued operations	4	9
Net Income	$ 42	$ 62
Shares (Denominator) (in millions):		
Weighted average shares outstanding for basic computation:		
Average shares outstanding	249	228
Adjustment to shares outstanding	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	249	228
Net effect of potentially dilutive shares (a)	—	1
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	249	229
Basic and Diluted Earnings per Share		
Earnings per share of common stock from continuing operations	$ 0.16	$ 0.23
Earnings per share of common stock from discontinued operations	0.01	0.04
Basic and diluted earnings per share	$ 0.17	$ 0.27

(a) There were no options to purchase shares of common stock that were excluded from the calculation of diluted EPS for the three months ended June 30, 2013 and 2012.

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(millions of dollars, except per share data)	
Income (Numerator):		
Net (Loss) Income from continuing operations	$ (392)	$ 113
Net Income from discontinued operations	4	17
Net (Loss) Income	$ (388)	$ 130
Shares (Denominator) (in millions):		
Weighted average shares outstanding for basic computation:		
Average shares outstanding	243	228
Adjustment to shares outstanding	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	243	228
Net effect of potentially dilutive shares (a)	—	1
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	243	229
Basic and Diluted Earnings per Share		
(Loss) Earnings per share of common stock from continuing operations	$ (1.61)	$ 0.50
Earnings per share of common stock from discontinued operations	0.01	0.07
Basic and diluted (loss) earnings per share	$ (1.60)	$ 0.57

(a) There were no options to purchase shares of common stock that were excluded from the calculation of diluted EPS for the six months ended June 30, 2013 and 2012.

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.

Treasury Stock

Premium on stock and other capital contributions on PHI's consolidated balance sheet at March 31, 2013 included approximately $2 million of treasury stock outstanding, representing 102,933 shares with a weighted-average price of $19.93. These shares were repurchased during the first quarter of 2013 to cover minimum withholding taxes of certain participants in PHI's Long-Term Incentive Plan and were reissued during the first and second quarters of 2013 to the PHI Retirement Savings Plan, which shares were used to provide PHI common stock to plan participants.

(13) <u>DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES</u>

Derivatives are used by Power Delivery to hedge commodity price risk, as well as by PHI, from time to time, to hedge interest rate risk.

In Power Delivery, 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.

ACE was ordered to enter into the SOCAs by the NJBPU, and under the SOCAs, ACE would receive payments from or make payments to electric generation facilities based on i) the difference between the fixed price in the SOCAs and the price for capacity that clears PJM and ii) ACE's annual proportion of the total New Jersey load relative to the other EDCs in New Jersey, which is currently estimated to be approximately 15 percent. ACE began applying derivative accounting to two of its SOCAs as of June 30, 2012 because the generators cleared the 2015-2016 PJM capacity auction in May 2012. In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. In June 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. The fair value of the derivatives embedded in the SOCAs are deferred as Regulatory Assets or Regulatory Liabilities because the NJBPU has allowed full recovery from ACE's distribution customers for all payments made by ACE, and ACE's distribution customers would be entitled to all payments received by ACE.

PHI also uses 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 income over the life of the debt issued as interest payments are made.

The tables below identify the balance sheet location and fair values of derivative instruments as of June 30, 2013 and December 31, 2012:

Balance Sheet Caption	As of June 30, 2013 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 (non-current assets)	$ —	$ 4	$ 4	$ —	$ 4
Total Derivative assets	—	4	4	—	4
Derivative liabilities (current liabilities)	—	(1)	(1)	1	—
Derivative liabilities (non-current liabilities)	—	(14)	(14)	—	(14)
Total Derivative liabilities	—	(15)	(15)	1	(14)
Net Derivative (liability) asset	$ —	$ (11)	$ (11)	$ 1	$ (10)

Balance Sheet Caption	As of December 31, 2012 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 (non-current assets)	$ —	$ 8	$ 8	$ —	$ 8
Total Derivative assets	—	8	8	—	8
Derivative liabilities (current liabilities)	—	(4)	(4)	—	(4)
Derivative liabilities (non-current liabilities)	—	(11)	(11)	—	(11)
Total Derivative liabilities	—	(15)	(15)	—	(15)
Net Derivative (liability) asset	$ —	$ (7)	$ (7)	$ —	$ (7)

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), PHI offsets the fair value amounts recognized for derivative assets and liabilities and the fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. All derivative assets and liabilities available to be offset under master netting arrangements were netted as of June 30, 2013 and December 31, 2012. The amount of cash collateral that was offset against these derivative positions is as follows:

	June 30, 2013	December 31, 2012
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 1	$ —

(a) Includes cash deposits on commodity brokerage accounts.

As of June 30, 2013 and December 31, 2012, 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

The tables below provide details regarding effective cash flow hedges included in PHI's consolidated balance sheets as of June 30, 2013 and 2012. Cash flow hedges are marked to market on the consolidated balance sheet with corresponding adjustments to AOCL for the effective portion of cash flow hedges. The data in the following tables indicate the cumulative net loss after-tax related to effective 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, 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	

	As of June 30, 2012		
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	$ 10	$ 1	242 months
Total	$ 10	$ 1	

Other Derivative Activity

Power Delivery

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 accordance with FASB guidance on regulated operations, offsetting regulatory liabilities or regulatory assets 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 SOCAs within which ACE's capacity derivatives are embedded. The following table indicates the net unrealized derivative gains and losses arising during the period that were deferred as Regulatory Liabilities and Regulatory Assets, respectively, and the net realized losses recognized in the consolidated statements of income (through Fuel and Purchased Energy expense) that were also deferred as Regulatory Assets for the three and six months ended June 30, 2013 and 2012 associated with these derivatives:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Net unrealized loss arising during the period	$ (9)	$ (1)	$ (7)	$ (5)
Net realized gain (loss) recognized during the period	1	(4)	(3)	(11)

As of June 30, 2013 and December 31, 2012, the quantities and positions of DPL's net outstanding natural gas commodity forward contracts and ACE's capacity derivatives associated with the SOCAs that did not qualify for hedge accounting were:

	June 30, 2013		December 31, 2012	
Commodity	Quantity	Net Position	Quantity	Net Position
DPL – Natural gas (one Million British Thermal Units (MMBtu))	3,272,500	Long	3,838,000	Long
ACE – Capacity (MWs)	180	Long	180	Long

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 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, 2013 and December 31, 2012, were zero and $4 million, respectively, before giving effect to offsetting transactions or collateral under master netting agreements. As of June 30, 2013 and December 31, 2012, DPL had posted no cash collateral against its gross derivative liability, resulting in a net liability of zero and $4 million, respectively. If DPL's debt ratings had been downgraded below investment grade as of June 30, 2013 and December 31, 2012, DPL's net settlement amounts, including both the fair value of its derivative liabilities and its normal purchase and normal sale contracts would have been approximately zero and $2 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately zero and $2 million, respectively, in addition to that which was posted as of June 30, 2013 and December 31, 2012. The net settlement and additional collateral amounts reflect the effect of offsetting transactions under master netting agreements.

DPL's primary source for posting cash collateral or letters of credit is PHI's credit facility. As of June 30, 2013 and December 31, 2012, 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 $595 million and $477 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, 2013 and December 31, 2012. 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, 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				
Derivative instruments (b)				
Capacity (d)	$ 4	$ —	$ —	$ 4
Cash equivalents				
Treasury fund	37	37	—	—
Executive deferred compensation plan assets				
Money market funds	14	14	—	—
Life insurance contracts	64	—	45	19
	$119	$ 51	$ 45	$ 23
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Capacity (d)	14	—	—	14
Executive deferred compensation plan liabilities				
Life insurance contracts	29	—	29	—
	$ 44	$ 1	$ 29	$ 14

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2013.
(b) The fair values of derivative assets and liabilities 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.
(d) Represents derivatives associated with ACE SOCAs.

Description	Total	Fair Value Measurements at December 31, 2012 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)				
Capacity (d)	$ 8	$ —	$ —	$ 8
Cash equivalents				
Treasury fund	27	27	—	—
Executive deferred compensation plan assets				
Money market funds	17	17	—	—
Life insurance contracts	60	—	42	18
	$112	$ 44	$ 42	$ 26
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ —	$ —	$ 4
Capacity (d)	11	—	—	11
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
	$ 43	$ —	$ 28	$ 15

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas options purchased by DPL as part of a natural gas hedging program approved by the DPSC.
(d) Represents derivatives associated with ACE SOCAs.

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 (NYMEX).

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 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, 2013. 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 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 categorized as level 3 include natural gas options used by DPL as part of a natural gas hedging program approved by the DPSC and capacity under the SOCAs entered into by ACE:

- DPL applies a Black-Scholes model to value its options with inputs, such as forward price curves, contract prices, contract volumes, the risk-free rate and implied volatility factors, that are based on a range of historical NYMEX option prices. DPL maintains valuation policies and procedures and reviews the validity and relevance of the inputs used to estimate the fair value of its options. As of June 30, 2013, all of these contracts classified as level 3 derivative instruments have settled.
- ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external valuation specialist to estimate annual zonal PJM capacity prices through the 2030-2031 auction. The capacity price forecast was based on various assumptions that impact the cost of constructing new generation facilities, including zonal load forecasts, zonal fuel and energy prices, generation capacity and transmission planning, and environmental legislation and regulation. ACE reviewed the assumptions and resulting capacity price forecast for reasonableness. ACE used the capacity price forecast to estimate future cash flows. A significant change in the forecasted prices would have a significant impact on the estimated fair value of the SOCAs. ACE employed a discount rate reflective of the estimated weighted average cost of capital for merchant generation companies since payments under the SOCAs are contingent on providing generation capacity.

The tables below summarize the primary unobservable inputs used to determine the fair value of PHI's level 3 instruments and the range of values that could be used for those inputs as of June 30, 2013 and December 31, 2012:

Type of Instrument	**Fair Value at June 30, 2013** *(millions of dollars)*	**Valuation Technique**	**Unobservable Input**	**Range**
Capacity contracts, net	$ (10)	Discounted cash flow	Discount rate	5% - 9%

Type of Instrument	**Fair Value at December 31, 2012** *(millions of dollars)*	**Valuation Technique**	**Unobservable Input**	**Range**
Natural gas options	$ (4)	Option model	Volatility factor	1.57 - 2.00
Capacity contracts, net	(3)	Discounted cash flow	Discount rate	5% - 9%

PHI used values within these ranges as part of its fair value estimates. A significant change in any of the unobservable inputs within these ranges would have an insignificant impact on the reported fair value as of June 30, 2013 and December 31, 2012.

Executive deferred compensation plan assets and liabilities 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, 2013 and 2012 are shown below:

	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)

	Six Months Ended June 30, 2012		
	Natural Gas	Life Insurance Contracts	Capacity
	(millions of dollars)		
Beginning balance as of January 1	$ (15)	$ 17	$ —
Total gains (losses) (realized and unrealized):			
Included in income	—	2	—
Included in accumulated other comprehensive loss	—	—	—
Included in regulatory liabilities and regulatory assets	(3)	—	(1)
Purchases	—	—	—
Issuances	—	—	—
Settlements	8	—	—
Transfers in (out) of level 3	—	—	—
Ending balance as of June 30	$ (10)	$ 19	$ (1)

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, 2013	2012
	(millions of dollars)	
Total net gains included in income for the period	$ 3	$ 2
Change in unrealized gains relating to assets still held at reporting date	$ 2	$ 2

Other Financial Instruments

The estimated fair values of PHI's 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, 2013 and December 31, 2012 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 categorized as level 1 is based on actual quoted trade prices for the debt in active markets on the measurement date.

The fair value of Long-term debt and Transition Bonds issued by ACE Funding 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, 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)	$5,054	$ —	$ 4,482	$ 572
Transition Bonds issued by ACE Funding (b)	311	—	311	—
Long-term project funding	13	—	—	13
	$5,378	$ —	$ 4,793	$ 585

(a) The carrying amount for Long-term debt is $4,525 million as of June 30, 2013.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $276 million as of June 30, 2013.

Description	Total	Fair Value Measurements at December 31, 2012 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)		
LIABILITIES				
Debt instruments				
Long-term debt (b)	$5,004	$ —	$ 4,517	$ 487
Transition Bonds issued by ACE Funding (c)	341	—	341	—
Long-term project funding	13	—	—	13
	$5,358	$ —	$ 4,858	$ 500

(a) Certain debt instruments that were categorized as level 1 at December 31, 2012, have been reclassified as level 2 to conform to the current period presentation.
(b) The carrying amount for Long-term debt is $4,177 million as of December 31, 2012.
(c) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $295 million as of December 31, 2012.

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

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 this time, ACE has concluded that a loss is reasonably possible with respect to this matter, but ACE was unable to estimate an amount or range of reasonably possible loss because (i) the damages sought are indeterminate, (ii) the proceedings are in the early stages, and (iii) 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. This case remains pending.

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. Pepco Energy Services disputes both the allegations regarding unauthorized charges and the claims of entitlement to compounded interest in their entirety, and has been in discussions with the school districts to attempt to resolve these claims. No litigation involving Pepco Energy Services related to these claims has commenced. As of June 30, 2013, the amount of loss that may be associated with these claims is not reasonably estimable, and Pepco Energy Services cannot estimate an amount or range of reasonably possible loss associated with the claims.

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, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation Regulated	Legacy Generation Non-Regulated	Other	Total
		(millions of dollars)			
Beginning balance as of January 1	$ 15	$ 7	$ 5	$ 2	$ 29
Accruals	2	—	—	1	3
Payments	1	1	—	2	4
Ending balance as of June 30	16	6	5	1	28
Less amounts in Other current liabilities	2	1	—	1	4
Amounts in Other deferred credits	$ 14	$ 5	$ 5	$—	$ 24

Conectiv Energy Wholesale Power Generation Sites

In July 2010, PHI sold the Conectiv Energy wholesale power generation business 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 preliminary 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 Peck's 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 on November 4, 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 the 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 ACE, DPL and Pepco, 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 ACE, DPL and 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 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 district court's order addresses only the liability of the test case defendant. PHI has concluded that a loss is reasonably possible with respect to this matter, but PHI was 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 operated by Pepco Energy Services until the facility was deactivated in June 2012, and a transmission and distribution facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The letter stated that 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 10-15 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 the companies 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.

In December 2012, DDOE approved the RI/FS work plan. RI/FS field work commenced in January 2013 and is still in progress.

As required by the court order entering the consent decree, the parties submitted a report to the court on May 23, 2013, regarding the status of the RI/FS. The status report described the substantial progress made to date, explained several circumstances that have caused delay of the work and projected that the RI/FS field work will be completed by November 2013. The court approved the status report and directed the parties to submit another status report by May 24, 2014. The court also advised the parties that they are expected to continue to work diligently and expeditiously to complete the RI/FS.

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. Pepco is continuing discussions with DDOE regarding the need for any further response actions but expects that additional monitoring of shoreline sediments may be required.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened claims for civil penalties for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. Pepco and DDOE have reached an agreement in principle that would consist of a combination of a civil penalty and Supplemental Environmental Projects (SEPs) with a total cost to Pepco of approximately $1 million. Discussions with DDOE continue regarding the specific nature and scope of the SEPs, as well as the amount of DDOE's and the federal resource trustees' natural resource damage claim. This matter is expected to be resolved through the entry of a consent decree sometime in 2013. Based on discussions to date, PHI and Pepco do not believe that the resolution of these claims will have a material adverse effect on their respective financial conditions, results of operations or cash flows.

As a result of the oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility which involve pumping accumulated storm water to an aboveground 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.

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

Metal Bank Site

In January 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted Pepco (and contacted DPL in March 2013) 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 have executed the tolling agreement and will participate in 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). The letter requests that Pepco submit a plan of action for the investigation and capping of the right-of-way within 90 days. In its February 2013 response, Pepco informed MDE that under a 2000 asset purchase and sale agreement (the Sale Agreement), the buyer of Pepco's generation assets assumed environmental liability for hazardous substances, including ash, which remain on or have been removed from the generating stations. In July 2013, Pepco received a letter from the Maryland Attorney General's office on behalf of MDE, which takes the position that agreements between private parties do not operate to shift responsibility for compliance with landfill closure regulations and that Pepco, as the former owner and operator of a portion of the landfill, is responsible for compliance with closure requirements for that portion. The letter urges Pepco to work with GenOn concerning a closure plan and cap for the entire landfill and indicates that, absent an agreement between Pepco and GenOn concerning a closure plan and cap for the entire landfill or Pepco's submission of a plan to investigate and cap the portion of the landfill that Pepco owns, MDE will take formal action against Pepco to enforce the landfill closure regulations. In its July 22, 2013 response to the Maryland Attorney General's office, Pepco indicated, while reserving its rights under the Sale Agreement, its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way.

PHI and Pepco have determined that there is a loss associated with this matter for Pepco and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of less than $1 million to approximately $6 million. PHI and Pepco believe that the costs incurred in this matter will be recoverable from GenOn under the 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 (8), "Leasing Activities," 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 discussed above.

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 has determined that its tax position with respect to the tax benefits associated with the cross-border energy leases no longer meets the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded a non-cash charge of $377 million (after-tax) in the first quarter of 2013 (as discussed in Note (8), "Leasing Activities"), 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. Management believes that it can no longer support its conclusions regarding these business assumptions, and the tax effects of this change in conclusion are 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 was included in the charge recorded in the first quarter of 2013.

In the event that the IRS were to be successful in disallowing 100% of the tax benefits associated with these lease investments and recharacterizing 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 as described in Note (8), "Leasing Activities," was used to repay the short-term borrowings utilized to fund the advanced payment.

PHI continues to weigh its options with respect to its litigation with the IRS. Pursuant to an agreement reached by the parties before the judge in January 2013, further discovery in the case is effectively stayed until August 29, 2013. The current schedule for the case requires that discovery be concluded by December 31, 2013, with a likely trial date in the second half of 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, 2013, 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)	$54	$—	$—	$—	$ 54
Guarantees associated with disposal of Conectiv Energy assets (b)	13	—	—	—	13
Guaranteed lease residual values (c)	2	5	7	4	18
Total	$69	$ 5	$ 7	$ 4	$ 85

(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 $55 million, $8 million of which is a guaranty by PHI, $15 million by Pepco, $19 million by DPL and $13 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 Services Performance Contracts

Pepco Energy Services has a diverse portfolio of energy savings services 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 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, 2013, the remaining notional amount of Pepco Energy Services' energy savings guarantees on both completed projects and projects under construction totaled $464 million over the life of the multi-year performance contracts with the longest guarantee having a remaining term of 13 years. 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, 2013, 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 the life of the multi-year contract, with the longest guarantee having a remaining term of 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, 2013, Pepco Energy Services had an accrued liability of $1 million for its energy savings or combined heat and power performance contracts that it established during 2012. There was no significant change in the type of contracts issued during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012.

Dividends

On July 25, 2013, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable September 30, 2013, to stockholders of record on September 10, 2013.

(16) ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Balance, beginning of period	$ (41)	$ (34)	$ (42)	$ (34)
Treasury Lock				
Balance, beginning of period	(10)	(10)	(10)	(10)
Amount of net pre-tax loss reclassified to income:				
Interest expense	1	—	1	—
Total net pre-tax loss reclassified to income	1	—	1	—
Income Tax expense	—	—	—	—
Net change during period	1	—	1	—
Balance, end of period	(9)	(10)	(9)	(10)
Pension and Other Postretirement Benefit Plans				
Balance, beginning of period	(31)	(24)	(32)	(24)
Amount of net pre-tax loss reclassified (from) to income:				
Other Operation and Maintenance expense	(1)	(6)	1	(5)
Total net pre-tax loss reclassified (from) to income	(1)	(6)	1	(5)
Income Tax expense	—	(4)	(1)	(3)
Net change during period	(1)	(2)	—	(2)
Balance, end of period	(32)	(26)	(32)	(26)
Balance, end of period	$ (41)	$ (36)	$ (41)	$ (36)

(17) DISCONTINUED OPERATIONS

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. Further, the assets and liabilities of Pepco Energy Services' retail electric and natural gas supply businesses are reported as held for disposition as of each date presented in the accompanying consolidated balance sheets.

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,	
	2013	2012	2013	2012
	(millions of dollars)			
Operating revenue	$ 34	$ 109	$ 84	$ 265
Income from operations of discontinued operations, net of income taxes (a)	$ 1	$ 9	$ 3	$ 17
Net gains associated with the 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	$ 9	$ 4	$ 17

(a) Includes income tax expense of zero and approximately $6 million for the three months ended June 30, 2013 and 2012, respectively, and approximately $1 million and $11 million for the six months ended June 30, 2013 and 2012, respectively.

(b) Includes income tax expense of approximately $1 million and zero for the three months ended June 30, 2013 and 2012, respectively, and zero for each of the six months ended June 30, 2013 and 2012.

The net gains associated with the accelerated disposition of retail electric and natural gas contracts, net of income taxes for the three months ended June 30, 2013, reflects the pre-tax loss of $3 million ($2 million after-tax) associated with the terminations of the retail electric customer supply and wholesale purchase obligations beyond June 30, 2013, and the pre-tax gain of $8 million ($5 million after-tax) recognized regarding 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.

The net gains associated with the accelerated disposition of retail electric and natural gas contracts, net of income taxes for the six months ended June 30, 2013, reflects the pre-tax gain of $5 million ($3 million after-tax) described above, partially offset by unrealized derivative losses that were previously included in AOCL and were reclassified to income because PHI determined that the hedged forecasted purchases of supply for customers were probable not to occur. Accordingly, in the first quarter of 2013, PHI recognized $4 million of pre-tax unrealized derivative losses ($2 million after-tax) that previously were included in AOCL as cash flow hedges.

Balance Sheet Information

As of June 30, 2013 and December 31, 2012, the retail energy supply business of Pepco Energy Services had net accounts receivable of $12 million and $33 million, respectively, inventory assets of $2 million and $3 million, respectively, gross derivative assets of zero and $1 million, respectively, other current assets of zero and $1 million, respectively, accrued liabilities of $9 million and $20 million, respectively, gross derivative liabilities of zero and $21 million, respectively, exclusive of the collateral pledged by Pepco Energy Services against the derivative liabilities, and other current liabilities of $3 million and $1 million, respectively. The fair values of the derivative assets and liabilities were considered levels 1 and 2 within the fair value hierarchy.

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.

The retail electric and natural gas supply businesses of Pepco Energy Services entered into energy commodity contracts in the form of natural gas futures, swaps, options and forward contracts to hedge commodity price risk in connection with the purchase of physical natural gas and electricity for distribution to customers. The primary risk management objective was to manage the spread between retail sales commitments and the cost of supply used to service those commitments to ensure stable cash flows and lock in favorable prices and margins when they became available. There were no derivatives for Pepco Energy Services as of June 30, 2013.

Commodity contracts held by the retail electric and natural gas supply businesses of Pepco Energy Services that were not designated for hedge accounting, did not qualify for hedge accounting, or did not meet the requirements for normal purchase and normal sale accounting, were marked to market through current earnings. Forward contracts that met the requirements for normal purchase and normal sale accounting were recorded on an accrual basis.

The table below identifies the balance sheet location and fair values of the retail electric and natural gas supply businesses' derivative instruments as of December 31, 2012:

	As of December 31, 2012				
Balance Sheet Caption	**Derivatives Designated as Hedging Instruments (a)**	**Other Derivative Instruments**	**Gross Derivative Instruments** *(millions of dollars)*	**Effects of Cash Collateral and Netting**	**Net Derivative Instruments**
Assets held for disposition (current assets)	$ —	$ 1	$ 1	$ —	$ 1
Total Derivative assets	—	1	1	—	1
Liabilities associated with assets held for disposition (current liabilities)	(10)	(9)	(19)	16	(3)
Liabilities associated with assets held for disposition (non-current liabilities)	(1)	(1)	(2)	2	—
Total Derivative liabilities	(11)	(10)	(21)	18	(3)
Net Derivative (liability) asset	$ (11)	$ (9)	$ (20)	$ 18	$ (2)

(a) Amounts included in Derivatives Designated as Hedging Instruments primarily consist of derivatives that were designated as cash flow hedges prior to Pepco Energy Services' election to discontinue cash flow hedge accounting for these derivatives.

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), the retail electric and natural gas supply businesses of Pepco Energy Services offset the fair value amounts recognized for derivative instruments and the fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. No derivative assets or liabilities were available to be offset under master netting arrangements as of December 31, 2012. The amount of cash collateral that was offset against these derivative positions is as follows:

	December 31, 2012 *(millions of dollars)*
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 18

(a) Includes cash deposits on commodity brokerage accounts.

As of December 31, 2012, all cash collateral pledged by the retail electric and natural gas supply businesses related to derivative instruments accounted for at fair value was entitled to offset under master netting agreements.

Derivatives Designated as Hedging Instruments

Cash Flow Hedges

For energy commodity contracts that are designated and qualify as cash flow hedges, the effective portion of the gain or loss on the derivative is reported as a component of AOCL and is reclassified into income in the same period or periods during which the hedged transactions affect income. Gains and losses on the derivative that are related to hedge ineffectiveness or the forecasted hedged transaction being probable not to occur are recognized in income. The retail energy supply business of Pepco Energy Services had elected to no longer apply cash flow hedge accounting to its energy derivatives. Amounts included in AOCL for these cash flow hedges as of June 30, 2013 and 2012 represent net losses on derivatives prior to the election to discontinue cash flow hedge accounting less amounts reclassified into income as the hedged transactions occurred or because the hedged transactions were deemed probable not to occur. Gains or losses on these derivatives after the election to discontinue cash flow hedge accounting were recognized in income.

The cash flow hedge activity during the three and six months ended June 30, 2013 and 2012 is provided in the tables below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Amount of net pre-tax loss arising during the period included in Accumulated Other Comprehensive Loss	$ —	$ —	$ —	$ —
Amount of net pre-tax loss reclassified into income:				
Effective portion:				
Income from Discontinued operations, Net of Income Taxes	2	12	10	25
Total net pre-tax loss reclassified into Income from Discontinued operations, Net of Income Taxes	2	12	10	25
Net pre-tax gain on commodity derivatives included in Accumulated Other Comprehensive Loss	$ 2	$ 12	$ 10	$ 25

(a) Included in the table above is a loss of $4 million for the six months ended June 30, 2013, which was reclassified from AOCL to Income from Discontinued operations, Net of Income Taxes because the forecasted hedged transactions were deemed probable not to occur. For the three months ended June 30, 2013, and for the three and six months ended June 30, 2012, no amounts were reclassified from AOCL to Income from Discontinued operations, Net of Income Taxes because the forecasted hedged transactions were deemed probable not to occur.

Cash Flow Hedges Included in Accumulated Other Comprehensive Loss

Cash flow hedges are marked to market on the balance sheet with corresponding adjustments to AOCL for effective cash flow hedges. As of June 30, 2013, all of the losses in AOCL that were associated with derivatives that the retail electric and natural gas supply businesses of Pepco Energy Services had previously designated as cash flow hedges have been reclassified to income. The table below provides details regarding effective cash flow hedges included in the retail electric and natural gas supply businesses of Pepco Energy Services' balance sheets as of June 30, 2012. Although the retail electric and natural gas supply businesses of Pepco Energy Services elected to no longer apply cash flow hedge accounting to its derivatives prior to June 30, 2012, gains or losses previously deferred in AOCL prior to the decision to discontinue cash flow hedge accounting remained in AOCL until the hedged forecasted transaction occurred unless it was deemed probable that the hedged forecasted transaction would not occur. The data in the following tables indicate the cumulative net loss after-tax related to effective 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, 2012		
Contracts	Accumulated Other Comprehensive Loss After-tax	Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Energy commodity (a)	$ 15	$ 13	23 months
Total	$ 15	$ 13	

(a) The unrealized derivative losses recorded in AOCL relate to forecasted physical natural gas and electricity purchases which are used to supply retail electric and natural gas supply contracts that are in gain positions and subject to accrual accounting. Under accrual accounting, no asset is recorded on Pepco Energy Services' balance sheet and the purchase cost is not recognized until the period of distribution.

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 from Discontinued Operations, Net of Income Taxes.

For the three and six months ended June 30, 2013 and 2012, the amount of the derivative gain (loss) for the retail electric and natural gas supply businesses of Pepco Energy Services recognized in Income from Discontinued Operations, Net of Income Taxes is provided in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Reclassification of mark-to-market to realized on settlement of contracts	$ 5	$ 7	$ 10	$ 17
Unrealized mark-to-market gain (loss)	—	5	—	(5)
Total net (loss) gain	$ 5	$ 12	$ 10	$ 12

As of June 30, 2013, the retail electric and natural gas supply businesses of Pepco Energy Services had no outstanding commodity forward contracts or derivative positions.

As of December 31, 2012, the retail electric and natural gas supply businesses of Pepco Energy Services had the following net outstanding commodity forward contract quantities and net position on derivatives that did not qualify for hedge accounting:

	December 31, 2012	
Commodity	Quantity	Net Position
Natural gas (MMBtu)	2,867,500	Long
Financial transmission rights (MWh)	181,008	Long
Electricity (MWh)	261,240	Long

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Operating Revenue	$ 469	$ 456	$ 946	$ 921
Operating Expenses				
Purchased energy	157	160	349	345
Other operation and maintenance	95	101	197	204
Depreciation and amortization	49	48	96	95
Other taxes	88	92	177	182
Total Operating Expenses	389	401	819	826
Operating Income	80	55	127	95
Other Income (Expenses)				
Interest expense	(28)	(24)	(54)	(49)
Other income	5	4	9	8
Total Other Expenses	(23)	(20)	(45)	(41)
Income Before Income Tax Expense	57	35	82	54
Income Tax Expense	20	8	22	3
Net Income	$ 37	$ 27	$ 60	$ 51

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 6	$ 9
Restricted cash equivalents	3	—
Accounts receivable, less allowance for uncollectible accounts of $13 million and $13 million, respectively	331	318
Inventories	72	69
Prepayments of income taxes	9	9
Income taxes receivable	101	31
Prepaid expenses and other	13	25
Total Current Assets	535	461
INVESTMENTS AND OTHER ASSETS		
Regulatory assets	512	487
Prepaid pension expense	343	353
Investment in trust	31	31
Income taxes receivable	35	102
Other	64	59
Total Investments and Other Assets	985	1,032
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	7,054	6,850
Accumulated depreciation	(2,722)	(2,705)
Net Property, Plant and Equipment	4,332	4,145
TOTAL ASSETS	$ 5,852	$ 5,638

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ —	$ 231
Current portion of long-term debt	375	200
Accounts payable and accrued liabilities	202	214
Accounts payable due to associated companies	35	41
Capital lease obligations due within one year	9	8
Taxes accrued	26	58
Interest accrued	20	17
Liabilities and accrued interest related to uncertain tax positions	24	—
Customer deposits	48	48
Other	60	58
Total Current Liabilities	799	875
DEFERRED CREDITS		
Regulatory liabilities	130	141
Deferred income tax liabilities, net	1,274	1,219
Investment tax credits	3	4
Other postretirement benefit obligations	68	66
Liabilities and accrued interest related to uncertain tax positions	9	53
Other	66	66
Total Deferred Credits	1,550	1,549
LONG-TERM LIABILITIES		
Long-term debt	1,575	1,501
Capital lease obligations	65	70
Total Long-Term Liabilities	1,640	1,571
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	930	755
Retained earnings	933	888
Total Equity	1,863	1,643
TOTAL LIABILITIES AND EQUITY	$ 5,852	$ 5,638

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, 2013	Six Months Ended June 30, 2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 60	$ 51
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	96	95
Deferred income taxes	46	127
Changes in:		
Accounts receivable	(18)	4
Inventories	(3)	(11)
Prepaid expenses	13	14
Regulatory assets and liabilities, net	(49)	(34)
Accounts payable and accrued liabilities	(17)	(2)
Prepaid pension expense, excluding contributions	10	11
Pension contributions	—	(85)
Income tax-related prepayments, receivables and payables	(55)	(129)
Interest accrued	3	—
Other assets and liabilities	(2)	(5)
Net Cash From Operating Activities	84	36
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(258)	(306)
Department of Energy capital reimbursement awards received	12	21
Changes in restricted cash equivalents	(3)	—
Net other investing activities	(4)	3
Net Cash Used By Investing Activities	(253)	(282)
FINANCING ACTIVITIES		
Dividends paid to Parent	(15)	—
Capital contributions from Parent	175	50
Issuances of long-term debt	250	200
Reacquisitions of long-term debt	—	(38)
(Repayments) issuances of short-term debt, net	(231)	34
Cost of issuances	(4)	(4)
Net other financing activities	(9)	(1)
Net Cash From Financing Activities	166	241
Net Decrease in Cash and Cash Equivalents	(3)	(5)
Cash and Cash Equivalents at Beginning of Period	9	12
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6	$ 7
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid for income taxes (includes payments to PHI for federal income taxes)	$ —	$ 1

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, 2012	100	$ —	$ 755	$ 888	$1,643
Net Income	—	—	—	23	23
Capital contribution from Parent	—	—	175	—	175
BALANCE, MARCH 31, 2013	100	—	930	911	1,841
Net Income	—	—	—	37	37
Dividends on common stock	—	—	—	(15)	(15)
BALANCE, JUNE 30, 2013	100	$ —	$ 930	$ 933	$1,863

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

<u>NOTES TO FINANCIAL STATEMENTS</u>

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).

(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, 2012. 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, 2013, in accordance with GAAP. The year-end December 31, 2012 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, 2013 may not be indicative of results that will be realized for the full year ending December 31, 2013.

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, 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 self-insurance reserves for general and auto 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 $77 million and $80 million for the three months ended June 30, 2013 and 2012, respectively, and $153 million and $159 million for the six months ended June 30, 2013 and 2012, respectively.

Reclassifications and Adjustments

Certain prior period amounts have been reclassified in order to conform to the current period presentation. The following adjustments have been recorded and are not considered material either individually or in the aggregate:

Income Tax Expense Adjustments

In the second quarter of 2012, Pepco recorded an adjustment to reduce Income Tax expense as a result of the reversal of interest expense erroneously recorded on certain effectively settled income tax positions in the first quarter of 2012. This adjustment resulted in a decrease to Income Tax expense of $1 million for the three months ended June 30, 2012.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

None.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (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 will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. Pepco will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between Pepco and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. Pepco is evaluating the impact of this new guidance on its financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the 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 new requirements are effective prospectively beginning with Pepco's March 31, 2014 financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. Pepco is currently evaluating the impact of this new guidance on its financial statements.

(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

Over the last several years, Pepco has proposed in each of its 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) was approved and implemented for electric service in Maryland and 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 District of Columbia Public Service Commission (DCPSC) to increase its electric distribution base rates by approximately $52.1 million annually, based on a requested return on equity (ROE) of 10.25%. The requested rate increase is for the purpose of recovering (i) Pepco's expenses associated with ongoing efforts to maintain safe and reliable service for its customers, (ii) Pepco's investment in infrastructure to maintain and harden the electric distribution system, and (iii) Pepco's investment in major reliability enhancement improvements. Evidentiary hearings are expected to begin on November 4, 2013 and a final DCPSC decision is expected in the first quarter of 2014.

Maryland

In December 2011, Pepco submitted an application with the Maryland Public Service Commission (MPSC) to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently reduced by Pepco to $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%. The order also reduced Pepco's depreciation rates, which lowered annual depreciation and amortization expenses by an estimated $27.3 million. The lower depreciation rates resulted from, among other things, the rebalancing of excess reserves for estimated future removal costs identified in a depreciation study conducted as part of the rate case filing. The identified excess reserves for estimated future removal costs, reported as Regulatory Liabilities, were reclassified to Accumulated Depreciation among various plant accounts. Among other things, the order also authorizes Pepco to recover the actual cost of advanced metering infrastructure (AMI) meters installed during the 2011 test year and states that cost recovery for AMI deployment will only be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new revenue rates and lower depreciation rates were 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 was for the purpose of recovering reliability enhancements to serve Maryland customers. 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 (as discussed below under "Reliability Task Forces"). 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 $27.8 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 requires that the cost of AMI meters be excluded from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system; however, the July 2012 MPSC ruling in

Pepco's previous electric distribution base rate case, which stated that Pepco may recover the costs of meters installed during the 2011 test year for that case, is not affected by the July 2013 order and the Maryland OPC's motion for rehearing in that case remains pending. As a result, costs for AMI meters will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system which are deferred and on which a return is earned. The order also approved a Grid Resiliency Charge 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 Pepco provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The MPSC did not approve the proposed acceleration of the tree-trimming cycle or the undergrounding of six distribution feeders. The MPSC 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 this July 12, 2013 order in the Circuit Court for the City of Baltimore. Pepco intends to file another electric distribution base rate case with the MPSC in the fourth quarter of 2013. Pepco is continuing to review the impact of the order and may also consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to the utility.

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 (MW) beginning in 2015. The order requires Pepco, Delmarva Power & Light Company (DPL) and Baltimore Gas and Electric Company (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 the Contract EDCs will recover the associated costs through surcharges on their 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. These circuit court appeals were consolidated in the Circuit Court for Baltimore City and stayed pending the issuance of a final order from the MPSC approving the form of contract.

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, in amounts proportional to their relative SOS loads, with the winning bidder. The MPSC stated that the order, which approves timely and complete recovery by the Contract EDCs of the costs associated with the contract, constitutes a binding commitment that shall not be subject to future modification or rescission by the MPSC. Despite this commitment from the MPSC, Pepco believes that the attempt by the MPSC to bind a future commission in this manner may be subject to legal challenge, which challenge, if successful, could impair the right of Pepco to recover its costs in the future. In addition, the MPSC excluded from the contract a provision that Pepco believes is important to mitigate its financial risk because the provision, had it been included, would have required Pepco to make payments to the winning bidder under the contract only to the extent it were able to recover those costs (for example, Pepco believes the excluded provision would have protected it in the event a significant number of its SOS customers elect to buy their energy from alternative energy suppliers). In light of the issuance of the MPSC's final order, the previously filed appeals of the MPSC's actions in this case before the circuit court are now proceeding. On June 4, 2013, Pepco entered into the contract in accordance with the terms of the MPSC's order; however, under the contract's own terms, it will not become effective, if at all, until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

Pepco believes it may be required to account for its proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because it would recover any payments under the contract from SOS customers. Assuming the contract, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, Pepco estimates that it would be required to record an aggregate derivative liability ranging from $40 million to $50 million with an offsetting regulatory asset in a like amount. These estimates and other assumptions made may change prior to the time that the contract becomes effective, if at all. Pepco has concluded that any accounting for this contract would not be required all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

Pepco is in the process of determining (i) the extent of the negative effect that the contract for new generation 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 contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of Pepco.

Reliability Task Forces

In July 2012, the Maryland governor signed an Executive Order directing his energy advisor, in collaboration with certain state agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the electric distribution system in Maryland. The resulting Grid Resiliency Task Force issued its report in September 2012, in which it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. Pepco's electric distribution base rate case filed with the MPSC on November 30, 2012 attempted to address the Grid Resiliency Task Force recommendations.

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. The options that are available for financing these efforts were also to be evaluated to identify required legislative or regulatory actions to implement these recommendations. On May 13, 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan of the DC Undergrounding Task Force to bury five dozen of the District of Columbia's most outage-prone power lines. Under this recommendation, (i) Pepco would bear approximately $500 million of the $1 billion estimated cost to complete this project, recovering those costs through surcharges on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the undergrounding project cost would be financed by the District of Columbia's issuance of municipal bonds, which bonds would be repaid through surcharges on the electric bills of Pepco District of Columbia customers (Pepco would not earn a return on the underground lines paid for with the proceeds received from the issuance of the bonds, but those lines would be transferred to Pepco to operate and maintain); and (iii) the remaining amount would be funded through the District of Columbia Department of Transportation's existing capital projects program. Legislation providing for implementation of the report recommendations was introduced in the Council of the District of Columbia on July 10, 2013. This legislation is expected to be voted upon by the City Council by the fourth quarter of 2013. The final step in the process would be DCPSC approval of the recommendations, a decision on which is expected by the first quarter of 2014.

MAPP Project

On August 24, 2012, the board of PJM terminated the Mid-Atlantic Power Pathway (MAPP) project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. As of December 31, 2012, Pepco's total costs related to the MAPP project were $64 million. In a 2008 Federal Energy Regulatory Commission (FERC) order approving incentives for the MAPP project, FERC authorized the recovery of prudently incurred abandoned costs in connection with the MAPP project. Consistent with this order, in December 2012, Pepco submitted a filing to FERC seeking recovery of $50 million of abandoned MAPP costs. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

Various protests were submitted in response to Pepco's December 2012 filing, arguing, among other things, that FERC should disallow a portion of the rate of return involving an incentive adder that would be applied to the abandoned costs, and requesting a hearing on various issues such as the amount of the ROE and the prudence of the costs. On February 28, 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by Pepco to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. Pepco believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. On April 1, 2013, PHI filed a rehearing request on behalf of Pepco of the February 28, 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that Pepco is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. Pepco cannot predict when a final FERC decision in this proceeding will be issued.

As of December 31, 2012, Pepco had placed in service $11 million of its total capital expenditures with respect to the MAPP project, which represented upgrades of existing substation assets that were expected to support the MAPP transmission line, transferred approximately $3 million of materials to inventories, for use on other projects, and reclassified the remaining $50 million of capital expenditures to a regulatory asset. During the first quarter of 2013, Pepco further transferred an additional $2 million of materials to inventories, for use on other projects, and expensed $1 million of abandoned costs as a result of FERC's disallowance noted above. During the second quarter of 2013, Pepco further transferred an additional $3 million of materials to inventories, for use on other projects, resulting in a regulatory asset of $44 million as of June 30, 2013. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. Pepco intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey filed a joint complaint with FERC against Pepco, DPL, an affiliate of Pepco, and Atlantic City Electric Company (ACE), an affiliate of Pepco, 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 Pepco provides. The complainants claim to 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. On April 3, 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.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

Pepco accounts for its participation in its parent’s single-employer plans, Pepco Holding’s non-contributory retirement plan (the PHI Retirement Plan) and 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, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $29 million and $30 million, respectively. Pepco’s allocated share was $11 million and $9 million, respectively, for the three months ended June 30, 2013 and 2012. PHI’s pension and other postretirement net periodic benefit cost for the six months ended June 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $54 million and $56 million, respectively. Pepco’s allocated share was $19 million and $20 million, respectively, for the six months ended June 30, 2013 and 2012.

In the first quarter of 2012, Pepco made a discretionary tax-deductible contribution to the PHI Retirement Plan of $85 million.

(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. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

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, 2013.

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, 2013 and December 31, 2012, 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 $595 million and $477 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.

Commercial Paper

Pepco maintains an on-going commercial paper program to address its short-term liquidity needs. As of June 30, 2013, 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, 2013. The weighted average interest rate for commercial paper issued by Pepco during the six months ended June 30, 2013 was 0.38% and the weighted average maturity of all commercial paper issued by Pepco during the six months ended June 30, 2013 was seven days.

(9) INCOME TAXES

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$20	35.0%	$12	35.0%	$29	35.0%	$ 19	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	3	5.3%	2	5.6%	5	6.1%	3	5.7%
Asset removal costs	(3)	(5.3)%	(4)	(11.5)%	(6)	(7.3)%	(7)	(12.8)%
Change in estimates and interest related to uncertain and effectively settled tax positions	1	1.8%	(1)	(3.5)%	(4)	(4.9)%	(11)	(20.2)%
Other, net	(1)	(1.7)%	(1)	(2.7)%	(2)	(2.1)%	(1)	(2.1)%
Income tax expense	$20	35.1%	$ 8	22.9%	$22	26.8%	$ 3	5.6%

Three Months Ended June 30, 2013 and 2012

Pepco's effective tax rates for the three months ended June 30, 2013 and 2012 and were 35.1% and 22.9%, respectively. The increase in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

Six Months Ended June 30, 2013 and 2012

Pepco's effective tax rates for the six months ended June 30, 2013 and 2012 were 26.8% and 5.6%, respectively. The increase in the effective tax rate primarily resulted from 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 has determined that it can 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 a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $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 Pepco recording a $5 million interest benefit in the first quarter of 2013.

In the first quarter of 2012, Pepco recorded benefits for changes in estimates and interest related to uncertain and effectively settled tax positions primarily due to the effective settlement with the Internal Revenue Service (IRS) with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position.

(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, 2013 and December 31, 2012. 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, 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				
Treasury fund	$ 3	$ 3	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	12	12	—	—
Life insurance contracts	59	—	40	19
	$ 74	$ 15	$ 40	$ 19
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 8	$ —	$ 8	$ —
	$ 8	$ —	$ 8	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2013.

Description	Total	Fair Value Measurements at December 31, 2012 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				
Executive deferred compensation plan assets				
Money market funds	$ 15	$ 15	$ —	$ —
Life insurance contracts	56	—	38	18
	$ 71	$ 15	$ 38	$ 18
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 9	$ —	$ 9	$ —
	$ 9	$ —	$ 9	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.

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 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, 2013. 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 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, 2013 and 2012, are shown below:

	Life Insurance Contracts Six Months Ended June 30,	
	2013	**2012**
	(millions of dollars)	
Beginning balance as of January 1	$ 18	$ 17
Total gains (losses) (realized and unrealized):		
Included in income	3	2
Included in accumulated other comprehensive loss	—	—
Purchases	—	—
Issuances	(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,	
	2013	**2012**
	(millions of dollars)	
Total gains included in income for the period	$ 3	$ 2
Change in unrealized gains relating to assets still held at reporting date	$ 2	$ 2

Other Financial Instruments

The estimated fair values of Pepco's 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, 2013 and December 31, 2012 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 1 is based on actual quoted trade prices for the debt in active markets on the measurement date.

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, 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)	$2,247	$ —	$ 2,247	$ —
	$2,247	$ —	$ 2,247	$ —

(a) The carrying amount for Long-term debt is $1,950 million as of June 30, 2013.

	Fair Value Measurements at December 31, 2012			
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)			
LIABILITIES				
Debt instruments				
Long-term debt (b)	$2,160	$ —	$ 2,160	$ —
	$2,160	$ —	$ 2,160	$ —

(a) Certain debt instruments that were categorized as level 1 at December 31, 2012, have been reclassified as level 2 to conform to the current period presentation.
(b) The carrying amount for Long-term debt is $1,701 million as of December 31, 2012.

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

(11) COMMITMENTS AND CONTINGENCIES

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, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
		(millions of dollars)	
Beginning balance as of January 1	$ 14	$ 3	$ 17
Accruals	2	—	2
Payments	1	—	1
Ending balance as of June 30	15	3	18
Less amounts in Other current liabilities	1	—	1
Amounts in Other deferred credits	$ 14	$ 3	$ 17

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 Peck's 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 on November 4, 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 the 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 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) 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 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 district court's order addresses only the liability of the test case defendant. Pepco has concluded that a loss is reasonably possible with respect to this matter, but Pepco was 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 operated by Pepco Energy Services, Inc. and its subsidiaries (Pepco Energy Services) until the facility was deactivated in June 2012, and a transmission and distribution facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The letter stated that 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 10-15 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 the companies 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.

In December 2012, DDOE approved the RI/FS work plan. RI/FS field work commenced in January 2013 and is still in progress. As required by the court order entering the consent decree, the parties submitted a report to the court on May 23, 2013, regarding the status of the RI/FS. The status report described the substantial progress made to date, explained several circumstances that have caused delay of the work and projected that the RI/FS field work will be completed by November 2013. The court approved the status report and directed the parties to submit another status report by May 24, 2014. The court also advised the parties that they are expected to continue to work diligently and expeditiously to complete the RI/FS.

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. Pepco is continuing discussions with DDOE regarding the need for any further response actions but expects that additional monitoring of shoreline sediments may be required.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened claims for civil penalties for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. Pepco and DDOE have reached an agreement in principle that would consist of a combination of a civil penalty and Supplemental Environmental Projects (SEPs) with a total cost to Pepco of approximately $1 million. Discussions with DDOE continue regarding the specific nature and scope of the SEPs, as well as the amount of DDOE's and the federal resource trustees' natural resource damage claim. This matter is expected to be resolved through the entry of a consent decree sometime in 2013. Based on discussions to date, PHI and Pepco do not believe that the resolution of these claims will have a material adverse effect on their respective financial conditions, results of operations or cash flows.

As a result of the oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility which involve pumping accumulated storm water to an aboveground 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.

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

Metal Bank Site

In January 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 has executed the tolling agreement and will participate in 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). The letter requests that Pepco submit a plan of action for the investigation and capping of the right-of-way within 90 days. In its February 2013 response, Pepco informed MDE that under a 2000 asset purchase and sale agreement (the Sale Agreement), the buyer of Pepco's generation assets assumed environmental liability for hazardous substances, including ash, which remain on or have been removed from the generating stations. In July 2013, Pepco received a letter from the Maryland Attorney General's office on behalf of MDE, which takes the position that agreements between private parties do not operate to shift responsibility for compliance with landfill closure regulations and that Pepco, as the former owner and operator of a portion of the landfill, is responsible for compliance with closure requirements for that portion. The letter urges Pepco to work with GenOn concerning a closure plan and cap for the entire landfill and indicates that, absent an agreement between Pepco and GenOn concerning a closure plan and cap for the entire landfill or Pepco's submission of a plan to investigate and cap the portion of the landfill that Pepco owns, MDE will take formal action against Pepco to enforce the landfill closure regulations. In its July 22, 2013 response to the Maryland Attorney General's office, Pepco indicated, while reserving its rights under the Sale Agreement, its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way.

Pepco has determined that there is a loss associated with this matter and has estimated that the costs for implementation of a closure plan and cap on the site are in the range of less than $1 million to approximately $6 million. Pepco believes that the costs incurred in this matter will be recoverable from GenOn under the 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, 2013 and 2012 were approximately $52 million and $52 million, respectively. PHI Service Company costs directly charged or allocated to Pepco for the six months ended June 30, 2013 and 2012 were approximately $107 million and $103 million, respectively.

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, 2013 and 2012 were approximately $4 million and $6 million, respectively. Amounts charged to Pepco by these companies for the six months ended June 30, 2013 and 2012 were approximately $12 million and $10 million, respectively.

As of June 30, 2013 and December 31, 2012, Pepco had the following balances on its balance sheets due to related parties:

	June 30, 2013	December 31, 2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (16)	$ (22)
Pepco Energy Services (b)	(19)	(18)
Other	—	(1)
Total	$ (35)	$ (41)

(a) Included in Accounts Payable Due to Associated Companies.

(b) Pepco bills customers on behalf of Pepco Energy Services where customers have selected Pepco Energy Services as their alternative energy supplier or 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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(millions of dollars)			
Operating Revenue				
Electric	$ 237	$ 235	$ 522	$ 494
Natural gas	29	24	114	98
Total Operating Revenue	266	259	636	592
Operating Expenses				
Purchased energy	121	122	280	265
Gas purchased	15	13	69	62
Other operation and maintenance	63	62	132	127
Depreciation and amortization	27	25	52	49
Other taxes	9	7	19	16
Total Operating Expenses	235	229	552	519
Operating Income	31	30	84	73
Other Income (Expenses)				
Interest expense	(12)	(11)	(25)	(22)
Other income	2	3	4	6
Total Other Expenses	(10)	(8)	(21)	(16)
Income Before Income Tax Expense	21	22	63	57
Income Tax Expense	9	9	25	23
Net Income	$ 12	$ 13	$ 38	$ 34

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3	$ 6
Accounts receivable, less allowance for uncollectible accounts of $14 million and $9 million, respectively	182	201
Inventories	56	53
Prepayments of income taxes	10	10
Income taxes receivable	5	10
Assets and accrued interest related to uncertain tax positions	18	—
Prepaid expenses and other	14	20
Total Current Assets	288	300
INVESTMENTS AND OTHER ASSETS		
Goodwill	8	8
Regulatory assets	284	288
Prepaid pension expense	235	232
Assets and accrued interest related to uncertain tax positions	3	20
Other	12	12
Total Investments and Other Assets	542	560
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	3,535	3,422
Accumulated depreciation	(1,011)	(1,000)
Net Property, Plant and Equipment	2,524	2,422
TOTAL ASSETS	$ 3,354	$ 3,282

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	June 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 214	$ 137
Current portion of long-term debt	250	250
Accounts payable and accrued liabilities	95	125
Accounts payable due to associated companies	18	20
Taxes accrued	3	4
Interest accrued	9	6
Derivative liabilities	—	4
Other	63	61
Total Current Liabilities	652	607
DEFERRED CREDITS		
Regulatory liabilities	240	258
Deferred income tax liabilities, net	726	697
Investment tax credits	5	5
Other postretirement benefit obligations	25	22
Other	36	41
Total Deferred Credits	1,032	1,023
LONG-TERM LIABILITIES		
Long-term debt	667	667
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	407	407
Retained earnings	596	578
Total Equity	1,003	985
TOTAL LIABILITIES AND EQUITY	$ 3,354	$ 3,282

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, 2013	Six Months Ended June 30, 2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 38	$ 34
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	52	49
Deferred income taxes	27	33
Changes in:		
Accounts receivable	19	25
Inventories	(3)	(6)
Regulatory assets and liabilities, net	(13)	(23)
Accounts payable and accrued liabilities	(21)	6
Pension contributions	(10)	(85)
Income tax-related prepayments, receivables and payables	(2)	(12)
Interest accrued	3	3
Other assets and liabilities	15	9
Net Cash From Operating Activities	105	33
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(164)	(145)
Net other investing activities	1	(2)
Net Cash Used By Investing Activities	(163)	(147)
FINANCING ACTIVITIES		
Dividends paid to Parent	(20)	—
Issuances of long-term debt	—	250
Reacquisitions of long-term debt	—	(66)
Issuances (repayments) of short-term debt, net	77	(47)
Cost of issuances	—	(3)
Net other financing activities	(2)	—
Net Cash From Financing Activities	55	134
Net (Decrease) Increase in Cash and Cash Equivalents	(3)	20
Cash and Cash Equivalents at Beginning of Period	6	5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 3	$ 25
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ (1)	$ (3)

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, 2012	1,000	$ —	$ 407	$ 578	$ 985
Net Income	—	—	—	26	26
BALANCE, MARCH 31, 2013	1,000	—	407	604	1,011
Net Income	—	—	—	12	12
Dividends on common stock	—	—	—	(20)	(20)
BALANCE, JUNE 30, 2013	1,000	$ —	$ 407	$ 596	$1,003

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).

(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, 2012. 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, 2013, in accordance with GAAP. The year-end December 31, 2012 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, 2013 may not be indicative of DPL's results that will be realized for the full year ending December 31, 2013.

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, 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 self-insurance reserves for general and auto 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 Renewable Energy Transactions

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 Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests.

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, 2013, PHI, through its DPL subsidiary, is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 megawatts (MWs) and one solar PPA with a 10 MW facility. 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 solar renewable energy credits (SRECs) from the solar facility up to certain amounts (as set forth below) at rates that are primarily fixed under the respective PPA. PHI has concluded that consolidation is not required for any of these PPAs under the Financial Accounting Standards Board (FASB) guidance on the consolidation of variable interest entities.

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 purchases under the three wind PPAs totaled $7 million and $6 million for the three months ended June 30, 2013 and 2012, respectively. DPL's purchases under the three wind PPAs totaled $17 million and $15 million for the six months ended June 30, 2013 and 2012, respectively.

The term of the agreement with the solar facility is 20 years and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. DPL's purchases under the solar agreement were less than $1 million for each of the three months ended June 30, 2013 and 2012, respectively. DPL's purchases under the solar agreement were less than $1 million for each of the six months ended June 30, 2013 and 2012, respectively.

On October 18, 2011, the Delaware Public Service Commission (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 (MWh) of energy produced by the fuel cell facilities over 21 years. DPL would have no liability 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, 2013 and 2012, 15 MWs and 3MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $3 million and less than $1 million to distribution customers for the three months ended June 30, 2013 and 2012, respectively. DPL billed $6 million and less than $1 million to distribution customers for the six months ended June 30, 2013 and 2012, respectively. DPL has concluded that consolidation under the variable interest entity consolidation guidance is not required for this arrangement.

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. All of DPL's goodwill was generated by DPL's acquisition of Conowingo Power Company in 1995. 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 reduce the 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 units; an adverse change in business conditions; an adverse regulatory action; or an impairment of DPL's long-lived assets. DPL concluded that an interim impairment test was not required during the six months ended June 30, 2013.

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, 2013 and 2012 and $8 million for each of the six months ended June 30, 2013 and 2012.

Reclassifications and Adjustments

Certain prior period amounts have been reclassified in order to conform to the current period presentation. The following adjustment has been recorded and is not considered material:

In the second quarter of 2012, DPL recorded an adjustment to correct an overstatement of unbilled revenue in its natural gas distribution business related to prior periods. The adjustment resulted in a decrease in Operating Revenue of $1 million for the three and six months ended June 30, 2012

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and financial liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosure requirements include information about the gross exposure of the instruments and the net exposure of the instruments under contractual netting arrangements, how the exposures are presented in the financial statements, and the terms and conditions of the contractual netting arrangements. DPL adopted the new guidance during the first quarter of 2013 and concluded it did not have a material impact on its financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (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 will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. DPL will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between DPL and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. DPL is evaluating the impact of this new guidance on its financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the 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 new requirements are effective prospectively beginning with DPL's March 31, 2014 financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. DPL is currently evaluating the impact of this new guidance on its financial statements.

(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, 2013. 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, 2012 indicated that goodwill was not impaired. For the six months ended June 30, 2013, DPL concluded that there were no events requiring it to perform an interim goodwill impairment test. DPL will perform its next annual impairment test as of November 1, 2013.

(7) REGULATORY MATTERS

Rate Proceedings

Over the last several years, DPL has proposed in each its 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) was approved and implemented for electric service in Maryland.
- A modified fixed variable rate design (MFVRD) is under consideration by the DPSC.

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 approved in concept in Delaware provides for 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. Although different from the BSA, DPL views the MFVRD as an appropriate distribution revenue decoupling mechanism.

Delaware

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. In August 2012, DPL made its 2012 GCR filing. The rates proposed in the 2012 GCR would result in a GCR decrease of approximately 22.3%. On September 18, 2012, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2012, subject to refund and pending final DPSC approval. On June 18, 2013, the DPSC issued an order approving a settlement agreement entered into on April 24, 2013 by DPL and the DPSC staff. This order provided that the proposed GCR rates as filed by DPL be approved.

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $42 million, based on a requested return on equity (ROE) of 10.25%. The requested rate increase seeks to recover expenses associated with DPL's ongoing 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. A final DPSC decision is expected by the first quarter of 2014.

Gas Distribution Base Rates

On December 7, 2012, DPL submitted an application with the DPSC to increase its natural gas distribution base rates. The filing seeks approval of an annual rate increase of approximately $12.0 million (as adjusted on July 15, 2013), based on a requested ROE of 10.25%. The requested rate increase is for the purposes of recovering expenses associated with DPL's ongoing efforts to maintain safe and reliable service and to provide enhanced customer service technology. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on February 5, 2013, subject to refund and pending final DPSC approval. On July 2, 2013, the DPSC approved DPL's request to implement an additional interim increase of $8 million on July 7, 2013, as permitted by state law. A final DPSC decision is expected by the fourth quarter of 2013.

Maryland

Electric Distribution Base Rates

On March 29, 2013, DPL submitted an application with the Maryland Public Service Commission (MPSC) to increase its electric distribution base rates by approximately $22.8 million, based on a requested ROE of 10.25%. The requested rate increase was for the purpose of recovering reliability enhancements to serve Maryland customers. DPL also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $10.2 million associated with its plan to accelerate investments in electric distribution 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 (as discussed below under "Reliability Task Forces"). Specific projects under DPL's Grid Resiliency Charge plan included accelerating its tree-trimming cycle and upgrading five additional feeders per year for two years. In addition, DPL proposed a reliability performance-based mechanism that would allow DPL to earn up to $500,000 as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $500,000 in total if DPL does not meet at least the minimum reliability performance targets. DPL requested that any credits or charges would flow through the proposed Grid Resiliency Charge rider.

On July 17, 2013, DPL, the MPSC staff and the Maryland Office of People's Counsel filed a joint motion with the MPSC, requesting that the MPSC approve a settlement entered into by the parties. The settlement provides for an annual rate increase of $15 million (an imputed ROE of 9.81%). The settlement provides for 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 amortizing the related deferred operation and maintenance expenses of approximately $6 million over a five-year period with the unamortized balance included in rate base. The settlement also provides for a Grid Resiliency Charge for recovery of costs totaling approximately $4.2 million associated with DPL's proposed plan to accelerate investments related to certain priority feeders, provided that DPL provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The settlement does not provide for approval of a portion of the Grid Resiliency Charge related to the proposed acceleration of the tree-trimming cycle, or DPL's proposed reliability performance-based mechanism. Under the settlement, the new rates would become effective on September 15, 2013 or as soon as reasonably practicable thereafter following effectiveness of the proposed MPSC order, which will occur on August 30, 2013 unless challenged by a party to the proceeding, or the MPSC modifies or reverses the proposed order or initiates further proceedings in the 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 MW beginning in 2015. The order requires DPL, Potomac Electric Power Company (Pepco) and Baltimore Gas and Electric Company (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 the Contract EDCs will recover the associated costs through surcharges on their 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. These circuit court appeals were consolidated in the Circuit Court for Baltimore City and stayed pending the issuance of a final order from the MPSC approving the form of contract.

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, in amounts proportional to their relative SOS loads, with the winning bidder. The MPSC stated that the order, which approves timely and complete recovery by the Contract EDCs of the costs associated with the contract, constitutes a binding commitment that shall not be subject to future modification or rescission by the MPSC. Despite this commitment from the MPSC, DPL believes that the attempt by the MPSC to bind a future commission in this manner may be subject to legal challenge, which challenge, if successful, could impair the right of DPL to recover its costs in the future. In addition, the MPSC excluded from the contract a provision that DPL believe is important to mitigate its financial risk because the provision, had it been included, would have required DPL to make payments to the winning bidder under the contract only to the extent it were able to recover those costs (for example, DPL believes the excluded provision would have protected it in the event a significant number of its SOS customers elect to buy their energy from alternative energy suppliers). In light of the issuance of the MPSC's final order, the previously filed appeals of the MPSC's actions in this case before the circuit court are now proceeding. On June 4, 2013, DPL entered into the contract in accordance with the terms of the MPSC's order; however, under the contract's own terms, it will not become effective, if at all, until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

DPL believes that it may be required to account for their proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because it would recover any payments under the contract from SOS customers. Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, DPL estimates that it would be required to record an aggregate derivative liability ranging from $15 million to $20 million with an offsetting regulatory asset in a like amount. These estimates and other assumptions made may change prior to the time that the contract becomes effective, if at all. DPL has concluded that any accounting for this contract would not be required until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

DPL is in the process of determining (i) the extent of the negative effect that the contract for new generation may have on DPL's credit metrics, as calculated by independent rating agencies that evaluate and rate DPL and each of its debt issuances, (ii) the effect on DPL's ability to recover its associated costs of the contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of DPL.

Reliability Task Force

In July 2012, the Maryland governor signed an Executive Order directing his energy advisor, in collaboration with certain state agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the electric distribution system in Maryland. The resulting Grid Resiliency Task Force issued its report in September 2012, in which it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. DPL's electric distribution base rate case filed with the MPSC on March 29, 2013 attempted to address the Grid Resiliency Task Force recommendations.

MAPP Project

On August 24, 2012, the board of PJM terminated the Mid-Atlantic Power Pathway (MAPP) project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. As of December 31, 2012, DPL's total costs related to the MAPP project were $38 million. In a 2008 Federal Energy Regulatory Commission (FERC) order approving incentives for the MAPP project, FERC authorized the recovery of prudently incurred abandoned costs in connection with the MAPP project. Consistent with this order, in December 2012, DPL submitted a filing to FERC seeking recovery of $38 million of abandoned MAPP costs. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

Various protests were submitted in response to DPL's December 2012 filing, arguing, among other things, that FERC should disallow a portion of the rate of return involving an incentive adder that would be applied to the abandoned costs, and requesting a hearing on various issues such as the amount of the ROE and the prudence of the costs. On February 28, 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by DPL to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. DPL believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. On April 1, 2013, PHI filed a rehearing request on behalf of DPL of the February 28, 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that DPL is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. DPL cannot predict when a final FERC decision in this proceeding will be issued.

As of December 31, 2012, DPL had reclassified all $38 million of capital expenditures with respect to the MAPP project to a regulatory asset. During the first quarter of 2013, DPL expensed $1 million of prudently incurred abandoned costs as a result of FERC's disallowance noted above, resulting in a regulatory asset of $37 million as of June 30, 2013. The regulatory asset includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. DPL intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land and land rights.

Transmission ROE Challenge

On February 27, 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, Pepco, an affiliate of DPL, and Atlantic City Electric Company (ACE), an affiliate of DPL, 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 DPL provides. The complainants claim to 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. On April 3, 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.

(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 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, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $29 million and $30 million, respectively. DPL's allocated share was $6 million for each of the three months ended June 30, 2013 and 2012. PHI's pension and other postretirement net periodic benefit cost for the six months ended June 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $54 million and $56 million, respectively. DPL's allocated share was $10 million and $12 million, respectively, for the six months ended June 30, 2013 and 2012.

In the first quarter of 2013, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan of $10 million. In the first quarter of 2012, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan of $85 million.

(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. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

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, 2013.

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, 2013 and December 31, 2012, 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 $595 million and $477 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.

Commercial Paper

DPL maintains an on-going commercial paper program to address its short-term liquidity needs. As of June 30, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had $109 million of commercial paper outstanding at June 30, 2013. The weighted average interest rate for commercial paper issued by DPL during the six months ended June 30, 2013 was 0.32% and the weighted average maturity of all commercial paper issued by DPL during the six months ended June 30, 2013 was two days.

(10) INCOME TAXES

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at federal statutory rate	$ 7	35.0%	$ 8	35.0%	$22	35.0%	$ 20	35.0%
Increases (decreases) resulting from:								
State income taxes, net of federal effect	1	4.8%	1	5.1%	3	4.8%	3	5.4%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	—	—	(1)	(1.6)%	—	(0.2)%
Other, net	1	3.1%	—	0.8%	1	1.5%	—	0.2%
Income tax expense	$ 9	42.9%	$ 9	40.9%	$25	39.7%	$ 23	40.4%

Three Months Ended June 30, 2013 and 2012

DPL's effective tax rates for the three months ended June 30, 2013 and 2012 were 42.9% and 40.9%, respectively.

Six Months Ended June 30, 2013 and 2012

DPL's effective tax rates for the six months ended June 30, 2013 and 2012 were 39.7% and 40.4%, respectively. The decrease in the effective tax rate primarily resulted from 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 has determined that it can 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 a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $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 DPL recording a $1 million interest benefit in the first quarter of 2013.

(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.

The tables below identify the balance sheet location and fair values of derivative instruments as of June 30, 2013 and December 31, 2012:

Balance Sheet Caption	As of June 30, 2013 Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
			(millions of dollars)		
Derivative liabilities (current liabilities)	$ —	$ (1)	$ (1)	$ 1	$ —
Net Derivative liability	$ —	$ (1)	$ (1)	$ 1	$ —

Balance Sheet Caption	As of December 31, 2012 Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
			(millions of dollars)		
Derivative liabilities (current liabilities)	$ —	$ (4)	$ (4)	$ —	$ (4)
Net Derivative liability	$ —	$ (4)	$ (4)	$ —	$ (4)

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), DPL offsets the fair value amounts recognized for derivative instruments and fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. All derivative assets and liabilities available to be offset under master netting arrangements were netted as of June 30, 2013 and December 31, 2012. The amount of cash collateral that was offset against these derivative positions is as follows:

	June 30, 2013	December 31, 2012
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 1	$ —

(a) Includes cash deposits on commodity brokerage accounts.

As of June 30, 2013 and December 31, 2012, 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 holds 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 accordance with FASB guidance on regulated operations, offsetting regulatory liabilities or regulatory assets 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 and six months ended June 30, 2013 and 2012, the net unrealized derivative gains and losses arising during the period that were deferred as Regulatory Liabilities and Regulatory Assets and the net realized losses recognized in the statements of income (through Purchased Energy and Gas Purchased expense) that were also deferred as Regulatory Assets are provided in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
		(millions of dollars)		
Net unrealized losses arising during the period	$ (2)	$ —	$ —	$ (4)
Net realized gains (losses) recognized during the period	1	(4)	(3)	(11)

As of June 30, 2013 and December 31, 2012, DPL had the following net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting:

	June 30, 2013		December 31, 2012	
Commodity	Quantity	Net Position	Quantity	Net Position
Natural gas (one Million British Thermal Units (MMBtu))	3,272,500	Long	3,838,000	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, 2013 and December 31, 2012, were zero and $4 million, respectively. As of those dates, DPL had posted no cash collateral in the normal course of business against its gross derivative liabilities, resulting in net liabilities of zero and $4 million, respectively. If DPL's debt ratings had been downgraded below investment grade as of June 30, 2013 and December 31, 2012, DPL's net settlement amounts would have been approximately zero and $2 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately zero and $2 million, respectively. The net settlement and additional collateral amounts reflect the effect of offsetting transactions under master netting agreements.

DPL's primary source for posting cash collateral or letters of credit is PHI's credit facility. As of June 30, 2013 and December 31, 2012, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries was $595 million and $477 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, 2013 and December 31, 2012. 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.

	Fair Value Measurements at June 30, 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				
Executive deferred compensation plan assets				
Money market funds	$ 1	$ 1	$ —	$ —
Life insurance contracts	1	—	—	1
	$ 2	$ 1	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
	$ 2	$ 1	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2013.
(b) The fair value of derivative liabilities 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.

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, 2012 (millions of dollars)			
ASSETS				
Executive deferred compensation plan assets				
Money market funds	$ 2	$ 2	$ —	$ —
Life insurance contracts	1	—	—	1
	$ 3	$ 2	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ —	$ —	$ 4
	$ 4	$ —	$ —	$ 4

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.
(b) The fair value of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas options 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 (NYMEX).

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.

Derivative instruments categorized as level 3 as of December 31, 2012, represent natural gas options used by DPL as part of a natural gas hedging program approved by the DPSC. DPL applies a Black-Scholes model to value its options with inputs, such as forward price curves, contract prices, contract volumes, the risk-free rate and implied volatility factors that are based on a range of historical NYMEX option prices. DPL maintains valuation policies and procedures and reviews the validity and relevance of the inputs used to estimate the fair value of its options. As of June 30, 2013, all of these contracts classified as level 3 derivative instruments have settled.

The table below summarizes the primary unobservable input used to determine the fair value of DPL's level 3 instruments and the range of values that could be used for the input as of December 31, 2012:

Type of Instrument	Fair Value at December 31, 2012	Valuation Technique	Unobservable Input	Range
	(millions of dollars)			
Natural gas options	$ (4)	Option model	Volatility factor	1.57 – 2.00

DPL used values within this range as part of its fair value estimates. A significant change in the unobservable input within this range would have an insignificant impact on the reported fair value as of December 31, 2012.

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, 2013 and 2012, are shown below:

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

	Six Months Ended June 30, 2012	
	Natural Gas	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ (15)	$ 1
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory assets	(3)	—
Purchases	—	—
Issuances	—	—
Settlements	8	—
Transfers in (out) of level 3	—	—
Ending balance as of June 30	$ (10)	$ 1

Other Financial Instruments

The estimated fair values of DPL's 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, 2013 and December 31, 2012 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 1 is based on actual quoted trade prices for the debt in active markets on the measurement date.

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, 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)	$942	$ —	$ 830	$ 112
	$942	$ —	$ 830	$ 112

(a) The carrying amount for Long-term debt is $917 million as of June 30, 2013.

Description	Total	Fair Value Measurements at December 31, 2012 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)	$990	$ —	$ 877	$ 113
	$990	$ —	$ 877	$ 113

(a) The carrying amount for Long-term debt is $917 million as of December 31, 2012.

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

(13) COMMITMENTS AND CONTINGENCIES

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, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Other	Total
		(millions of dollars)		
Beginning balance as of January 1	$ 1	$ 3	$ 2	$ 6
Accruals	—	—	1	1
Payments	—	1	2	3
Ending balance as of June 30	1	2	1	4
Less amounts in Other Current Liabilities	1	1	1	3
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 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 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 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 district court's order addresses only the liability of the test case defendant. DPL has concluded that a loss is reasonably possible with respect to this matter, but DPL was 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 March 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 has executed the tolling agreement and will participate in settlement discussions with the NOAA, the trustees and other PRPs.

(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, 2013 and 2012 were approximately $38 million and $37 million, respectively. PHI Service Company costs directly charged or allocated to DPL for the six months ended June 30, 2013 and 2012 were approximately $78 million and $74 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,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Intercompany lease transactions (a)	$ 1	$ 1	$ 2	$ 2

(a) Included in Electric revenue.

As of June 30, 2013 and December 31, 2012, DPL had the following balances on its balance sheets due to related parties:

	June 30, 2013	December 31, 2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (18)	$ (19)
Other	—	(1)
Total	$ (18)	$ (20)

(a) Included in Accounts Payable Due to Associated Companies.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(millions of dollars)			
Operating Revenue	$ 271	$ 270	$ 548	$ 526
Operating Expenses				
Purchased energy	154	163	311	329
Other operation and maintenance	58	56	119	112
Depreciation and amortization	32	27	63	55
Other taxes	2	4	6	8
Deferred electric service costs	(4)	(20)	(3)	(35)
Total Operating Expenses	242	230	496	469
Operating Income	29	40	52	57
Other Income (Expenses)				
Interest expense	(18)	(18)	(35)	(35)
Other income	—	1	—	2
Total Other Expenses	(18)	(17)	(35)	(33)
Income Before Income Tax Expense	11	23	17	24
Income Tax Expense	4	9	1	8
Net Income	$ 7	$ 14	$ 16	$ 16

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4	$ 6
Restricted cash equivalents	9	10
Accounts receivable, less allowance for uncollectible accounts of $10 million and $11 million, respectively	193	192
Inventories	32	30
Prepayments of income taxes	17	27
Income taxes receivable	111	5
Assets and accrued interest related to uncertain tax positions	14	—
Prepaid expenses and other	53	11
Total Current Assets	433	281
INVESTMENTS AND OTHER ASSETS		
Regulatory assets	648	694
Prepaid pension expense	112	88
Income taxes receivable	27	133
Restricted cash equivalents	15	17
Assets and accrued interest related to uncertain tax positions	6	12
Derivative assets	4	8
Other	12	12
Total Investments and Other Assets	824	964
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	2,863	2,771
Accumulated depreciation	(791)	(787)
Net Property, Plant and Equipment	2,072	1,984
TOTAL ASSETS	$3,329	$ 3,229

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 64	$ 133
Current portion of long-term debt	109	108
Accounts payable and accrued liabilities	152	147
Accounts payable due to associated companies	13	14
Taxes accrued	17	10
Interest accrued	14	15
Customer deposits	25	25
Other	17	22
Total Current Liabilities	411	474
DEFERRED CREDITS		
Regulatory liabilities	68	102
Deferred income tax liabilities, net	789	766
Investment tax credits	6	6
Other postretirement benefit obligations	36	34
Derivative liabilities	14	11
Other	16	18
Total Deferred Credits	929	937
LONG-TERM LIABILITIES		
Long-term debt	860	760
Transition Bonds issued by ACE Funding	236	256
Total Long-Term Liabilities	1,096	1,016
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
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	576
Retained earnings	216	200
Total Equity	893	802
TOTAL LIABILITIES AND EQUITY	$ 3,329	$ 3,229

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, 2013	Six Months Ended June 30, 2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 16	$ 16
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	63	55
Deferred income taxes	21	64
Changes in:		
Prepaid expenses	(39)	(43)
Regulatory assets and liabilities, net	(5)	(36)
Accounts payable and accrued liabilities	14	5
Pension contributions	(30)	(30)
Income tax-related prepayments, receivables and payables	5	(47)
Other assets and liabilities	4	(3)
Net Cash From (Used by) Operating Activities	49	(19)
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(141)	(114)
Department of Energy capital reimbursement awards received	—	1
Net other investing activities	3	2
Net Cash Used By Investing Activities	(138)	(111)
FINANCING ACTIVITIES		
Dividends paid to Parent	—	(15)
Capital contributions from Parent	75	—
Issuances of long-term debt	100	—
Reacquisitions of long-term debt	(19)	(18)
(Repayments) issuances of short-term debt, net	(69)	74
Net other financing activities	—	1
Net Cash From Financing Activities	87	42
Net Decrease in Cash and Cash Equivalents	(2)	(88)
Cash and Cash Equivalents at Beginning of Period	6	91
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 4	$ 3
SUPPLEMENTAL DISCLOSURE OF 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, 2012	8,546,017	$ 26	$ 576	$ 200	$802
Net Income	—	—	—	9	9
BALANCE, MARCH 31, 2013	8,546,017	26	576	209	811
Net Income	—	—	—	7	7
Capital contribution from Parent	—	—	75	—	75
BALANCE, JUNE 30, 2013	8,546,017	$ 26	$ 651	$ 216	$893

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).

(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, 2012. 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, 2013, in accordance with GAAP. The year-end December 31, 2012 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, 2013 may not be indicative of ACE's results that will be realized for the full year ending December 31, 2013.

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, 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 self-insurance reserves for general and auto 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.

ACE Power Purchase Agreements

ACE is a party to three power purchase agreements (PPAs) with unaffiliated, non-utility generators (NUGs) totaling 459 megawatts (MWs). One of the agreements ends in 2016 and the other two end in 2024. Since 2004, 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 applied the scope exemption from the consolidation guidance for enterprises that have not been able to obtain such information.

Purchase activities with the NUGs, including excess power purchases not covered by the PPA, for the three months ended June 30, 2013 and 2012 were approximately $53 million and $49 million, respectively, of which approximately $48 million and $47 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs for the six months ended June 30, 2013 and 2012 were approximately $107 million and $100 million, respectively, of which approximately $103 million and $98 million, respectively, consisted of power purchases under the PPAs. The power purchase costs are recoverable from ACE's customers through regulated rates.

Atlantic City Electric Transition Funding LLC

Atlantic City Electric Transition Funding LLC (ACE Funding) was established in 2001 by ACE solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of bonds (Transition Bonds). The proceeds of the sale of each series of Transition Bonds have been transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect non-bypassable transition bond charges (the Transition Bond Charges) from ACE customers pursuant to bondable stranded costs rate orders issued by the New Jersey Board of Public Utilities (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). ACE collects the Transition Bond Charges from its customers on behalf of ACE Funding and the holders of the Transition Bonds. 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 the Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding and PHI consolidates ACE Funding in its consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

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. The SOCAs were established under a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey. The SOCAs are 15-year, financially settled transactions approved by the NJBPU that allow generation companies to receive payments from, or require them to make payments to, ACE based on the difference between the fixed price in the SOCAs and the price for capacity that clears PJM Interconnection, LLC (PJM). Each of the other electric distribution companies (EDCs) in New Jersey has entered into SOCAs having the same terms with the same generation companies. ACE's share of the payments received from or the payments made to the generation companies is currently estimated to be approximately 15 percent, based on its proportionate share of the total New Jersey electric load for all EDCs. The NJBPU has ordered that ACE is obligated to distribute to its distribution customers all payments it receives from the generation companies and may recover from its distribution customers all payments it makes to the generation companies. For additional discussion about the SOCAs, see Note (6), “Regulatory Matters.”

In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. For each SOCA that clears the capacity auction, ACE records a derivative asset (liability) for the estimated fair value of that SOCA and records an offsetting regulatory liability (asset) as described in more detail in Note (10), “Derivative Instruments and Hedging Activities,” and Note (11), “Fair Value Disclosures.” Effective July 1, 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. ACE has concluded that consolidation of the generation companies is not required.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in ACE’s gross revenues were $2 million and $3 million for the three months ended June 30, 2013 and 2012, respectively, and $5 million and $7 million for the six months ended June 30, 2013 and 2012, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and financial liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosure requirements include information about the gross exposure of the instruments and the net exposure of the instruments under contractual netting arrangements, how the exposures are presented in the financial statements, and the terms and conditions of the contractual netting arrangements. ACE adopted the new guidance during the first quarter of 2013 and concluded it did not have a material impact on its consolidated financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (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 will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. ACE will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between ACE and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. ACE is evaluating the impact of this new guidance on its consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the 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 new requirements are effective prospectively beginning with

ACE's March 31, 2014 consolidated financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. ACE is currently evaluating the impact of this new guidance on its consolidated financial statements.

(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

Electric Distribution Base Rates

On December 11, 2012, ACE submitted an application with the NJBPU, updated on January 4, 2013, to increase its electric distribution base rates by approximately $70.4 million (excluding sales-and-use taxes), based on a requested ROE of 10.25%. This proposed net increase was comprised of (i) a proposed increase to ACE's distribution rates of approximately $72.1 million and (ii) a net decrease to ACE's Regulatory Asset Recovery Charge (RARC) (costs associated with deferred, NJBPU-approved expenses incurred as part of ACE's public service obligation) in the amount of approximately $1.7 million. The requested rate increase was primarily for the purposes of continuing to implement reliability-related investments and recovering system restoration costs associated with the derecho storm in June 2012 and Hurricane Sandy in October 2012. On June 21, 2013, the NJBPU approved a settlement of the parties (the NJ Rate Settlement) providing for an increase in ACE's distribution base rates in the amount of $25.5 million, based on an ROE of 9.75%. The base distribution revenue increase includes full recovery of the approximately $70.0 million in incremental storm restoration costs incurred as a result of recent major storm events, including the derecho storm and Hurricane Sandy, by including the related capital costs of approximately $44.2 million in rate base and amortizing the related deferred operation and maintenance expenses of approximately $25.8 million over a three-year period. In addition, depreciation expense will be reduced approximately $8.3 million per year. The NJ Rate Settlement also includes approximately $4.9 million of current RARC, but eliminates the RARC going forward. Rates were effective on July 1, 2013.

In a March 20, 2013 order, the NJBPU established a generic proceeding to evaluate the prudency of major storm event restoration costs and expenses. Each New Jersey EDC was directed to file a separate proceeding for the evaluation of these costs. Those portions of ACE's electric base rate filing pertaining to the recovery of major storm event expenditures were to be evaluated in the context of the generic proceeding. On April 9, 2013, ACE filed a petition with the NJBPU to comply with the NJBPU's generic storm cost order. All other issues in ACE's base rate filing remained unchanged in the electric base rate proceeding discussed above. In its order approving the NJ Rate Settlement, the NJBPU found that (i) ACE's April 9, 2013 petition met all the requirements of the NJBPU's March 20, 2013 order, and (ii) the major storm event costs for the June 2012 derecho storm and Hurricane Sandy may be recovered in ACE's electric distribution base rate case, discussed above.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012, 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 NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program for low income customers) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the projected deferred under-recovered balance related to the NUGs of $113.8 million as of May 31, 2012 through a four-year amortization schedule. In June 2012, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on July 1, 2012. The net impact of adjusting the charges (consisting of both the annual impact of the proposed four-year amortization of the historical under-recovered NUG balances of $127.0 million as of June 30, 2012 and the going-forward cost recovery of all the other charges for the period July 1, 2012 through May 31, 2013, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $55.3 million. The rates were deemed “provisional” because ACE’s filing was not updated for actual revenues and expenses for May and June 2012 until the March 5, 2013 petition described below was filed, after which a review by the NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the New Jersey Office of Administrative Law (OAL) for possible hearing.

On March 5, 2013, ACE submitted a new 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 NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program and ACE’s uncollected accounts and (iii) operating costs associated with ACE’s residential appliance cycling program. The filing proposed to recover the forecasted above-market NUG costs of approximately $67.9 million for the period June 1, 2013 through May 31, 2014, the projected deferred under-recovered balance related to the NUGs of approximately $40.8 million as of May 31, 2013, and an additional approximately $32.9 million associated with the deferred under-recovered balance that is being amortized over a four-year amortization period. In May 2013, NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on June 1, 2013. The net impact of adjusting the charges updated for actual data through March 31, 2013 (consisting of both the second year impact of the stipulated four-year amortization of the historical under-recovered NUG balances and the going-forward cost recovery of all the other charges for the period June 1, 2013 through May 31, 2014, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $52.2 million (this rate increase is in addition to the approximately $55.3 million approved by the NJBPU in June 2012, as discussed in the above paragraph). The rates were deemed “provisional” because ACE’s filing was not updated for actual revenues and expenses for April and May 2013. A review by NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the OAL for possible hearing.

Standard Offer Capacity Agreements

In April 2011, ACE entered into three SOCAs by order of the NJBPU, each with a different generation company, as more fully described in Note (2), “Significant Accounting Policies – Consolidation of Variable Interest Entities – ACE Standard Offer Capacity Agreements” and Note (10), “Derivative Instruments and Hedging Activities.” 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 dispute is pending before the NJBPU and has been referred to an Administrative Law Judge for further consideration. On April 11, 2013, the Superior Court of New Jersey Appellate Division issued an order consolidating the EDCs’ state court appeal of the NJBPU order (filed by the EDCs with the Appellate Division of the New Jersey Superior Court in June 2011) with a similar challenge filed by several generators and instructing the Administrative Law Judge to complete proceedings by June 15, 2013. The NJBPU filed a motion for clarification of the Appellate Division order, seeking an extension of time to complete the proceedings at the OAL. On June 28, 2013, the Appellate Division issued an order staying the consolidated appeals until September 30, 2013, and requiring the proceedings before the OAL and the NJBPU to be completed by that time.

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 New Jersey law under which the SOCAs were established on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In September 2012, the District Court denied motions for summary judgment filed by ACE and the other plaintiffs, as well as cross-motions filed by defendants. A bench trial was completed in May 2013 and final arguments were heard by the District Court Judge on June 17, 2013. It has not been determined when the District Court will issue 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.

Transmission ROE Challenge

On February 27, 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 the Federal Energy Regulatory Commission (FERC) against ACE, Potomac Electric Power Company (Pepco), an affiliate of ACE, and Delmarva Power & Light Company (DPL), an affiliate of ACE, 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 ACE provides. The complainants claim to 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. On April 3, 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.

(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 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, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $29 million and $30 million, respectively. ACE's allocated share was $5 million and $6 million, respectively, for the three months ended June 30, 2013 and 2012. PHI's pension and other postretirement net periodic benefit cost for the six months ended June 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $54 million and $56 million, respectively. ACE's allocated share was $10 million and $12 million, respectively, for the six months ended June 30, 2013 and 2012.

In the first quarter of 2013, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan of $30 million. In the first quarter of 2012, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan of $30 million.

(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. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

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, 2013.

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, 2013 and December 31, 2012, 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 $595 million and $477 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.

Commercial Paper

ACE maintains an on-going commercial paper program to address its short-term liquidity needs. As of June 30, 2013, the maximum capacity available under the program was $250 million, subject to available borrowing capacity under the credit facility.

ACE had $46 million of commercial paper outstanding at June 30, 2013. The weighted average interest rate for commercial paper issued by ACE during the six months ended June 30, 2013 was 0.34% and the weighted average maturity of all commercial paper issued by ACE during the six months ended June 30, 2013 was four days.

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, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.95%, 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, 2013.

Bond Payments

In April 2013, 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 Redemptions

On May 30, 2013, ACE redeemed, prior to maturity, at par plus accrued interest, all $4.4 million outstanding weekly rate pollution control revenue refunding bonds due 2017, issued by the Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit.

Financing Activities Subsequent to June 30, 2013

Bond Payments

In July 2013, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

(9) INCOME TAXES

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 4	35.0%	$ 8	35.0%	$ 6	35.0%	$ 8	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	1	9.1%	1	4.2%	1	5.9%	1	4.0%
Change in estimates and interest related to uncertain and effectively settled tax positions	1	9.1%	—	0.8%	(9)	(52.9)%	(1)	(4.0)%
Other, net	(2)	(16.8)%	—	(0.9)%	3	17.9%	—	(1.7)%
Consolidated income tax expense	$ 4	36.4%	$ 9	39.1%	$ 1	5.9%	$ 8	33.3%

Three Months ended June 30, 2013 and 2012

ACE's consolidated effective tax rates for the three months ended June 30, 2013 and 2012 were 36.4% and 39.1%, respectively.

Six Months ended June 30, 2013 and 2012

ACE's consolidated effective tax rates for the six months ended June 30, 2013 and 2012 were 5.9% and 33.3%, 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. In the first quarter of 2012, ACE recorded an interest benefit as a result of the effective settlement with the Internal Revenue Service with respect to the methodology used historically to calculate deductible mixed service 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 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 has determined that it can 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 a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $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 ACE recording a $6 million interest benefit in the first quarter of 2013.

(10) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

ACE was ordered to enter into the SOCAs by the NJBPU, and under the SOCAs, ACE would receive payments from or make payments to electric generation facilities based on (i) the difference between the fixed price in the SOCAs and the price for capacity that clears PJM and (ii) ACE's annual proportion of the total New Jersey load relative to the other EDCs in New Jersey, which is currently estimated to be 15 percent. ACE began applying derivative accounting to two of its SOCAs as of June 30, 2012 because the generators cleared the 2015-2016 PJM capacity auction in May 2012. In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. In June 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. The fair value of the derivatives embedded in the SOCAs are deferred as Regulatory Assets or Regulatory Liabilities because the NJBPU has allowed full recovery from ACE's distribution customers for all payments made by ACE, and ACE's distribution customers would be entitled to all payments received by ACE.

As of June 30, 2013 and December 31, 2012, ACE had non-current Derivative Assets of $4 million and $8 million, respectively, and non-current Derivative Liabilities of $14 million and $11 million, respectively, associated with the two SOCAs and an offsetting Regulatory Liability and Regulatory Asset, respectively, of the same amounts. As of June 30, 2013 and December 31, 2012, ACE had 180 MWs of capacity in a long position, with no collateral or netting applicable to the capacity. Unrealized gains and losses associated with these capacity derivatives, which netted to unrealized losses of $7 million and $1 million for the three and six months ended June 30, 2013 and 2012, respectively, have been deferred as Regulatory Liabilities and Regulatory Assets.

(11) 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, 2013 and December 31, 2012. 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, 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				
Derivative instruments (b)				
Capacity (c)	$ 4	$ —	$ —	$ 4
Cash equivalents				
Treasury fund	24	24	—	—
	$ 28	$ 24	$ —	$ 4
LIABILITIES				
Derivative instruments (b)				
Capacity (c)	$ 14	$ —	$ —	$ 14
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
	$ 15	$ —	$ 1	$ 14

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the six months ended June 30, 2013.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents derivatives associated with ACE SOCAs.

	Fair Value Measurements at December 31, 2012			
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 (b)				
Capacity (c)	$ 8	$ —	$ —	$ 8
Cash equivalents				
Treasury fund	27	27	—	—
	$ 35	$ 27	$ —	$ 8
LIABILITIES				
Derivative instruments (b)				
Capacity (c)	$ 11	$ —	$ —	$ 11
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 1	—	1	—
	$ 12	$ —	$ 1	$ 11

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents derivatives associated with ACE SOCAs.

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.

Derivative instruments categorized as level 3 represent capacity under the SOCAs entered into by ACE.

ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external valuation specialist to estimate annual zonal PJM capacity prices through the 2030-2031 auction. The capacity price forecast was based on various assumptions that impact the cost of constructing new generation facilities, including zonal load forecasts, zonal fuel and energy prices, generation capacity and transmission planning, and environmental legislation and regulation. ACE reviewed the assumptions and resulting capacity price forecast for reasonableness. ACE used the capacity price forecast to estimate future cash flows. A significant change in the forecasted prices would have a significant impact on the estimated fair value of the SOCAs. ACE employed a discount rate reflective of the estimated weighted average cost of capital for merchant generation companies since payments under the SOCAs are contingent on providing generation capacity.

The tables below summarize the primary unobservable inputs used to determine the fair value of ACE's level 3 instruments and the range of values that could be used for those inputs as of June 30, 2013 and December 31, 2012:

Type of Instrument	Fair Value at June 30, 2013 (millions of dollars)	Valuation Technique	Unobservable Input	Range
Capacity contracts, net	$ (10)	Discounted cash flow	Discount rate	5% - 9%

Type of Instrument	Fair Value at December 31, 2012 (millions of dollars)	Valuation Technique	Unobservable Input	Range
Capacity contracts, net	$ (3)	Discounted cash flow	Discount rate	5% - 9%

ACE used values within these ranges as part of its fair value estimates. A significant change in any of the unobservable inputs within these ranges would have an insignificant impact on the reported fair value as of June 30, 2013 and December 31, 2012.

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 and 2012 is shown below:

	Capacity Six Months Ended June 30, 2013	2012
	(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)	(1)
Purchases	—	—
Issuances	—	—
Settlements	—	—
Transfers in (out) of level 3	—	—
Ending balance as of June 30	$ (10)	$ (1)

Other Financial Instruments

The estimated fair values of ACE's 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, 2013 and December 31, 2012 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 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.

Description	Fair Value Measurements at June 30, 2013 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)	$1,053	$ —	$ 832	$ 221
Transition Bonds issued by ACE Funding (b)	311	—	311	—
	$1,364	$ —	$ 1,143	$ 221

(a) The carrying amount for Long-term debt is $929 million as of June 30, 2013.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $276 million as of June 30, 2013.

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, 2012			
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,016	$ —	$ 884	$ 132
Transition Bonds issued by ACE Funding (b)	341	—	341	—
	$1,357	$ —	$ 1,225	$ 132

(a) The carrying amount for Long-term debt is $829 million as of December 31, 2012.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $295 million as of December 31, 2012.

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

(12) COMMITMENTS AND CONTINGENCIES

General Litigation

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 this time, ACE has concluded that a loss is reasonably possible with respect to this matter, but ACE was unable to estimate an amount or range of reasonably possible loss because (i) the damages sought are indeterminate, (ii) the proceedings are in the early stages, and (iii) 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. This case remains pending.

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, 2013 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 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 district court's order addresses only the liability of the test case defendant. ACE has concluded that a loss is reasonably possible with respect to this matter, but ACE was 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.

(13) 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, 2013 and 2012 were approximately $28 million and $28 million, respectively. PHI Service Company costs directly charged or allocated to ACE for the six months ended June 30, 2013 and 2012 were approximately $59 million and $56 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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(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, 2013 and December 31, 2012, ACE had the following balances on its consolidated balance sheets due to related parties:

	June 30, 2013	December 31, 2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (12)	$ (13)
Other	(1)	(1)
Total	$ (13)	$ (14)

(a) Included in Accounts Payable Due to Associated Companies.

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 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, high voltage underground transmission cabling, low voltage construction and maintenance services, and the design, construction and operation of combined heat and power and central energy plants. For additional discussion, see "Pepco Energy Services" below.

Each of Power Delivery and Pepco Energy Services constitutes a separate segment for financial reporting purposes. A third segment, Other Non-Regulated, includes the portfolio of cross-border energy lease investments held by PCI.

The following table sets forth the percentage contributions to consolidated operating revenue and consolidated operating (loss) income from continuing operations attributable to PHI segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Percentage of Consolidated Operating Revenue				
Power Delivery	96%	92%	114%	92%
Pepco Energy Services	5%	7%	6%	7%
Other Non-Regulated	—	1%	(20)%	1%
Corporate and Other	(1)%	—	—	—
Percentage of Consolidated Operating (Loss) Income				
Power Delivery	106%	91%	(253)%	86%
Pepco Energy Services	2%	(1)%	(5)%	1%
Other Non-Regulated	(11)%	9%	368%	9%
Corporate and Other	3%	1%	(10)%	4%
Percentage of Power Delivery Operating Revenue				
Power Delivery Electric	97%	98%	95%	95%
Power Delivery Gas	3%	2%	5%	5%

Power Delivery

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

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. In this report, 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 the Federal Energy Regulatory Commission (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, 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 Delaware Public Service Commission (DPSC).

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 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.

Since 2010, PHI has implemented comprehensive reliability enhancement plans which include various initiatives to improve electrical system reliability, including:

- the identification and upgrading of under-performing feeder lines;
- the addition of new facilities to support load;
- the installation of distribution automation systems on both the overhead and underground network systems;
- the rejuvenation and replacement of underground residential cables;
- selective undergrounding of portions of existing above-ground primary feeder lines, where appropriate to improve reliability;
- improvements to substation supply lines; and
- enhanced vegetation management.

Power Delivery Initiatives and Activities

Smart Grid

PHI is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, provide timely and accurate customer information and address government energy reduction goals. A central component of the smart grid is advanced metering infrastructure (AMI), which is a system that collects, measures and analyzes energy usage data from advanced digital electric and gas meters known as smart meters. The installation of smart meters is subject to the approval of applicable state regulators. The District of Columbia Public Service Commission (DCPSC), Maryland Public Service Commission (MPSC) and DPSC have approved the creation of regulatory assets to defer AMI costs between rate cases, as well as the accrual of returns 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, the recovery of such costs will be allowed only if Pepco demonstrates that the AMI system is cost effective. Approval of AMI has been deferred by the New Jersey Board of Public Utilities (NJBPU) for ACE in New Jersey.

Meter installation and activation are substantially complete for Pepco customers in the District of Columbia and are expected to be completed in the third quarter of 2013 for Pepco customers in Maryland. In 2012, the MPSC approved the deployment of AMI for electric customers in DPL's Maryland service territory, and installation began in the second quarter of 2013. Electric meter installation and activation are complete for DPL electric customers in Delaware; installation of smart meters for natural gas delivery customers in Delaware is ongoing.

In April 2010, PHI signed agreements to formalize $168 million in awards from the U.S. Department of Energy to support the rollout of smart grid initiatives. In the Pepco service area, $149 million was awarded for AMI, direct load control, distribution automation and communications infrastructure, while in the ACE service area, $19 million was awarded for direct load control, distribution automation and communications infrastructure. The grants effectively reduce the project costs of these initiatives. The cumulative award payments received by Pepco and ACE as of June 30, 2013 were $131 million and $15 million, respectively.

Mitigation of Regulatory Lag

An important factor in the ability of each of Pepco, DPL and ACE to earn its authorized rate of return is the willingness of applicable public service commissions to adequately recognize forward-looking costs in the utility's rate structure in order to address the shortfall in revenues 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." Each of Pepco, DPL and ACE is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, Pepco's and DPL's District of Columbia, Delaware and Maryland base rate case filings in 2011 each included a request for approval from the applicable state regulatory commissions of (i) a reliability investment recovery mechanism (RIM) to recover reliability-related capital expenditures incurred between base rate cases and (ii) the use by the applicable utility of fully forecasted test years in future base rate cases. In June 2012, the MPSC rejected Pepco's and DPL's requests to implement the RIM and did not endorse the use by Pepco and DPL of fully forecasted test years in future rate cases. However, the MPSC did permit an adjustment to the rate base of Pepco and DPL to reflect the actual cost of reliability plant additions outside the test year. In the District of Columbia, the DCPSC denied Pepco's request for approval of a RIM in 2012, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases. In Delaware, a settlement agreement approved by the DPSC in DPL's electric distribution base rate case did not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it did provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag.

Each of PHI's utility subsidiaries will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag. There can be no assurance that any attempts by PHI's utility subsidiaries to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, PHI's utility subsidiaries plan to file rate cases at least annually in an effort to align more closely the revenue and cash flow levels of PHI's utility subsidiaries with other operation and maintenance spending and capital investments. Pepco filed its electric distribution base rate case in March 2013 in the District of Columbia, and expects to file its next electric distribution base rate case in Maryland by the end of 2013. DPL filed electric distribution base rate cases in both Delaware and Maryland in March 2013, and filed a natural gas distribution case in December 2012. ACE filed an electric distribution base rate case in December 2012.

In their respective electric distribution base rate cases filed in Maryland, each of Pepco and DPL included a proposed three-year Grid Resiliency Charge rider intended to reduce regulatory lag. In July 2013, the MPSC issued an order for Pepco that only partially approved the proposed Grid Resiliency Charge. See Note (7), "Regulatory Matters – Rate Proceedings," to the consolidated financial statements of PHI for more information about these base rate cases. On July 26, 2013, Pepco filed a notice of appeal of this MPSC order. Furthermore, Pepco is continuing to review the impact of this order and consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to Pepco.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system.

As a result, PHI updated its five-year projected capital expenditures to remove MAPP-related expenditures to reflect the PJM decision. As of December 31, 2012, PHI's total costs related to the MAPP project were approximately $102 million. In a 2008 FERC order approving incentives for the MAPP project, FERC authorized the recovery of prudently incurred abandoned costs in connection with the MAPP project. Consistent with this order, in December 2012, PHI submitted a filing to FERC seeking recovery over a period of five years of $88 million of abandoned MAPP costs. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by PHI to be $2 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. PHI believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. In April 2013, PHI filed a rehearing request of the February 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that PHI is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. PHI cannot predict when a final FERC decision in this proceeding will be issued.

As of December 31, 2012, PHI had placed in service $11 million of its total capital expenditures with respect to the MAPP project, which represented upgrades of existing substation assets that were expected to support the MAPP transmission line, transferred approximately $3 million of materials to inventories, for use on other projects, and reclassified the remaining $88 million of capital expenditures to a regulatory asset. During the first quarter of 2013, PHI further transferred an additional $2 million of materials to inventories, for use on other projects, and expensed $2 million of abandoned costs as a result of FERC's disallowance noted above. During the second quarter of 2013, PHI further transferred an additional $3 million of materials to inventories, for use on other projects, resulting in a regulatory asset of $81 million as of June 30, 2013. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. PHI intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

Transmission ROE Challenge

On February 27, 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, 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 claim to 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. On April 3, 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.

Pepco Energy Services

Since 2010, Pepco Energy Services has been focused on growing its energy savings performance contracting services business in the federal, state and local government markets. Activity in the state and local government markets, which are Pepco Energy Services' largest markets, slowed significantly in 2012, due to, among other factors, lower energy prices that have lessened the economic benefits of energy savings projects and the reluctance of state and local governments to incur new debt associated with these projects. As a result of the slowdown, Pepco Energy Services believes that new business in these markets will remain challenged for the foreseeable future. Consequently, Pepco Energy Services reduced resources and personnel in 2012, has limited geographic expansion in the energy savings services business and has refocused its existing resources on developing business in the federal government market and continuing to pursue combined heat and power projects.

PHI guarantees the obligations of Pepco Energy Services under certain of its energy savings performance, combined heat and power and construction contracts. At June 30, 2013, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $219 million.

Other Non-Regulated

Cross-Border Energy Lease Investments

Through its subsidiary Potomac Capital Investment Corporation and its subsidiaries (PCI), PHI held a portfolio of cross-border energy lease investments. These investments comprised the majority of the "Other Non-Regulated" segment. As discussed in Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," PHI is involved in ongoing litigation with the IRS concerning certain benefits associated with its 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 has determined that its tax position with respect to the benefits associated with its cross-border energy leases no longer meets the more-likely-than-not standard of recognition for accounting purposes, and the Other Non-Regulated segment recorded a non-cash charge of $323 million (after-tax) in the first quarter of 2013, consisting of the following components:

- A non-cash pre-tax charge of $373 million ($307 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 has been recorded in the consolidated statement of income as a reduction in Other Operating revenue.
- 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 has been recorded in the consolidated statement of income as an increase in income tax expense. 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 and $66 million for the Other Non-Regulated and Corporate and Other segments, respectively.

In March 2013, PHI began to pursue the early termination of all of its remaining cross-border energy lease investments with its lessees. During the second quarter of 2013, PHI terminated early its interest in five of the six remaining lease investments. PHI received aggregate net cash proceeds of $693 million (net of aggregate termination payments of $1.4 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 $14 million ($9 million after-tax) in the second quarter of 2013, representing the excess of the carrying value of the terminated leases over the net cash proceeds received.

During July 2013, PHI entered into an agreement with the lessee of the last remaining PHI lease investment which provides for the early termination of such lease investment. Upon closing, on July 26, 2013, PHI received aggregate net cash proceeds of $180 million (net of aggregate termination payments of $665 million used to retire the non-recourse debt associated with the terminated leases) and expects to record in the third quarter of 2013 a pre-tax gain, including transaction costs, of approximately $11 million ($7 million after-tax), representing the excess of the net cash proceeds received over the carrying value of the terminated leases. The aggregate financial impact upon completion of the early terminations of the cross-border energy lease investments in 2013 is expected to be a pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax).

After each early termination transaction was closed for each of the six cross-border energy lease investments, PHI retained no continuing involvement in the terminated lease investments. Upon completion of the termination of its last lease investment in July 2013, PHI completed the disposal of the cross-border energy lease component of its business (which represented a substantial portion of the Other Non-Regulated segment's earnings) and, as a result, expects to report the operations associated with this component of its business as a discontinued operation beginning in the third quarter of 2013, at which time this component will no longer be a part of PHI's Other Non-Regulated segment for financial reporting purposes. For additional information concerning these cross-border energy lease investments, see Note (8), "Leasing Activities – Investment in Finance Leases Held in Trust," and Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments" to the consolidated financial statements of PHI.

Other Operations

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 both Consolidated Edison's cross-border lease transaction and another taxpayer's structured transactions, (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 represents 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 will 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.

Discontinued Operations

In December 2009, PHI announced the wind-down of the retail energy supply component of the Pepco Energy Services business which is comprised of the retail electric and retail 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 are being accounted for as a discontinued operation and are no longer a part of the Pepco Energy Services segment for financial reporting purposes.

Earnings Overview

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

Net income for the three months ended June 30, 2013 and 2012, by operating segment, is set forth in the table below (in millions of dollars):

	2013	2012	Change
Power Delivery	$ 56	$54	$ 2
Pepco Energy Services	1	(1)	2
Other Non-Regulated	(15)	7	(22)
Corporate and Other	(4)	(7)	3
Net Income from Continuing Operations	38	53	(15)
Discontinued Operations	4	9	(5)
Total PHI Net Income	$ 42	$62	$ (20)

Net income from continuing operations for the three months ended June 30, 2013 was $38 million, or $0.16 per share, compared to net income from continuing operations of $53 million, or $0.23 per share, for the three months ended June 30, 2012.

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

After-tax loss, including transaction costs, on early termination of certain cross-border energy lease investments ($14 million pre-tax)	$ 9
Change in estimate associated with state income taxes related to the reduction of the carrying value of PCI's cross-border energy lease investments recorded in the first quarter of 2013	$ 6

Excluding the items listed above for the three months ended June 30, 2013, net income from continuing operations would have been $53 million, or $0.22 per share. PHI discloses net income from continuing operations and related per share data excluding these items 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 accounting principles generally accepted in the United States (GAAP).

Net income from discontinued operations was $4 million, or $0.01 per share, for the three months ended June 30, 2013, and $9 million, or $0.04 per share, for the three months ended June 30, 2012.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $2 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 $4 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012.
- A decrease of $5 million associated with ACE BGS, primarily attributable to a decrease in unbilled revenue.
- A decrease of $5 million associated with Default Electricity Supply margins for DPL Delaware, primarily due to favorable adjustments in 2012 related to allowed returns on net uncollectible expense and regulatory taxes.
- A decrease of $3 million due to higher interest expense resulting from an increase in outstanding debt.
- A decrease of $2 million due to non-weather related average customer usage in New Jersey.
- A decrease of $2 million due to lower transmission revenue related to a less favorable FERC formula rate true-up and the impact of peak-load adjustments, partially offset by higher rates related to increases in transmission plant investment.

Pepco Energy Services' $2 million increase in earnings was primarily due to the following in its Energy Services business:

- An increase of $2 million due to lower other operation and maintenance expense.
- An increase of $2 million due to asset impairment charges in 2012 that did not reoccur in 2013.

Other Non-Regulated's $22 million decrease in earnings was primarily due to the following:

- A decrease of $9 million related to the loss on early termination of certain cross-border energy lease investments in the second quarter of 2013.
- A decrease of $8 million related to lower cross-border energy lease investment earnings in 2013 as a result of holding fewer cross-border energy lease investments during the three months ended June 30, 2013 as compared to the three months ended June 30, 2012.
- A charge of $6 million to reflect a change in estimate associated with state income taxes related to the reduction of the carrying value of PCI's cross-border energy lease investments recorded in the first quarter of 2013.

Corporate and Other's $3 million decrease in net loss was primarily due to unfavorable income tax adjustments in 2012 related to the New Jersey Corporation Business Tax audit for tax years 2004 through 2009.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

Net (loss) income for the six months ended June 30, 2013 and 2012, by operating segment, is set forth in the table below (in millions of dollars):

	2013	2012	Change
Power Delivery	$ 114	$101	$ 13
Pepco Energy Services	4	1	3
Other Non-Regulated	(436)	17	(453)
Corporate and Other	(74)	(6)	(68)
Net (Loss) Income from Continuing Operations	(392)	113	(505)
Discontinued Operations	4	17	(13)
Total PHI Net (Loss) Income	$(388)	$130	$ (518)

Net loss from continuing operations for the six months ended June 30, 2013 was $392 million, or $1.61 per share, compared to net income from continuing operations of $113 million, or $0.50 per share, for the six months ended June 30, 2012.

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

Charge to reduce the carrying value of PCI's cross-border energy lease investments ($373 million pre-tax)	$ 313
Charge to reflect the anticipated additional interest expense on estimated federal and state income tax obligations allocated to the Other Non-Regulated and the Corporate and Other segments (as if each were a separate taxpayer) resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments ($127 million pre-tax)	$ 82
Charge to establish valuation allowances related to certain PCI deferred tax assets	$ 101
After-tax loss, including transaction costs, on early termination of certain cross-border energy lease investments ($14 million pre-tax)	$ 9

Excluding the items listed above for the six months ended June 30, 2013, net income from continuing operations would have been $113 million, or $0.47 per share. PHI discloses net income from continuing operations and related per share data excluding these items 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 income from discontinued operations was $4 million, or $0.01 per share, for the six months ended June 30, 2013 and $17 million, or $0.07 per share, for the six months ended June 30, 2012.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $13 million increase in earnings was primarily due to the following:

- An increase of $26 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 $8 million primarily due to higher sales from colder winter weather.
- A decrease of $5 million due to higher interest expense resulting from an increase in outstanding debt.
- A decrease of $5 million associated with Default Electricity Supply margins for DPL Delaware, primarily due to favorable adjustments in 2012 related to allowed returns on net uncollectible expense and regulatory taxes.
- A decrease of $4 million due to lower transmission revenue related to a less favorable FERC formula rate true-up and the impact of peak-load adjustments, partially offset by higher rates related to increases in transmission plant investment.
- A decrease of $3 million associated with lower interest benefits recorded in 2013 related to uncertain and effectively settled tax positions.
- A decrease of $2 million due to higher operation and maintenance expense, primarily associated with incremental winter storm restoration costs, employee-related costs and the write-off of disallowed MAPP and associated transmission project costs, partially offset by higher system maintenance in 2012 and the allowed recovery of certain customer service costs incurred in 2011 and 2012 (in accordance with an MPSC order).

Pepco Energy Services' $3 million increase in earnings was primarily due to the following in its Energy Services business:

- An increase of $2 million due to lower other operation and maintenance expense.
- An increase of $2 million due to asset impairment charges in 2012 that did not reoccur in 2013.

Other Non-Regulated's $453 million decrease in earnings was primarily due to the following:

- A charge of $329 million related to a change in assessment regarding the tax benefits related to the cross-border energy lease investments, consisting of a $313 million charge to reduce the carrying value of the investments and a $16 million 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.
- A charge of $101 million in the first quarter of 2013 to establish valuation allowances against certain PCI deferred tax assets.
- A decrease of $14 million associated with lower cross-border energy lease investment earnings as a result of holding fewer cross-border energy lease investments during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012.
- A decrease of $9 million related to the loss on early termination of certain cross-border energy lease investments in the second quarter of 2013.

Corporate and Other's $68 million increase in net loss was primarily due to an after-tax charge of $66 million to reflect the anticipated additional interest expense allocated to the Corporate and Other segment 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.

Consolidated Results of Operations

The following results of operations discussion compares the three months ended June 30, 2013 to the three months ended June 30, 2012. 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:

	2013	2012	Change
Power Delivery	$1,006	$ 984	$ 22
Pepco Energy Services	49	76	(27)
Other Non-Regulated	3	14	(11)
Corporate and Other	(5)	(4)	(1)
Total Operating Revenue	$1,053	$1,070	$ (17)

Power Delivery Business

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

	2013	2012	Change
Regulated T&D Electric Revenue	$ 508	$472	$ 36
Default Electricity Supply Revenue	453	474	(21)
Other Electric Revenue	16	14	2
Total Electric Operating Revenue	977	960	17
Regulated Gas Revenue	24	19	5
Other Gas Revenue	5	5	—
Total Gas Operating Revenue	29	24	5
Total Power Delivery Operating Revenue	$1,006	$984	$ 22

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 include 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

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 170	$ 154	$ 16
Commercial and industrial	241	230	11
Transmission and other	97	88	9
Total Regulated T&D Electric Revenue	$ 508	$ 472	$ 36

	2013	2012	Change
Regulated T&D Electric Sales (Gigawatt hours (GWh))			
Residential	3,567	3,571	(4)
Commercial and industrial	7,553	7,807	(254)
Transmission and other	52	57	(5)
Total Regulated T&D Electric Sales	11,172	11,435	(263)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,641	1,638	3
Commercial and industrial	199	199	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,842	1,839	3

Regulated T&D Electric Revenue increased by $36 million primarily due to:

- An increase of $28 million due to distribution rate increases (Pepco in the District of Columbia effective October 2012, and in Maryland effective July 2012; DPL in Maryland and Delaware effective July 2012; and ACE effective November 2012).
- An increase of $5 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 $3 million in transmission revenue primarily attributable to higher rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.

- An increase of $3 million primarily due to a rate increase in the New Jersey Societal Benefit Charge (related to the New Jersey Societal Benefit Program, a public interest program for low income customers) effective July 2012 (which is offset in Deferred Electric Service Costs).
- An increase of $3 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $2 million primarily due to DPL's Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Fuel and Purchased Energy and Depreciation and Amortization).
- An increase of $1 million in transmission revenue primarily attributable to higher capacity revenue as a result of expanding Maryland demand-side management programs (which is substantially offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million due to lower ACE and DPL non-weather related average customer usage.
- A decrease of $4 million in transmission revenue primarily attributable to less favorable FERC formula rate true-ups.
- A decrease of $3 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes), primarily the result of a utility tax rate decrease effective July 2012 that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.
- A decrease of $1 million in transmission revenue primarily attributable to a peak-load decrease effective January 2013.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$286	$314	$ (28)
Commercial and industrial	129	135	(6)
Other	38	25	13
Total Default Electricity Supply Revenue	$453	$474	$ (21)

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.

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	2,847	2,982	(135)
Commercial and industrial	1,224	1,402	(178)
Other	11	14	(3)
Total Default Electricity Supply Sales	4,082	4,398	(316)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,343	1,399	(56)
Commercial and industrial	126	133	(7)
Other	—	—	—
Total Default Electricity Supply Customers	1,469	1,532	(63)

Default Electricity Supply Revenue decreased by $21 million primarily due to:

- A decrease of $21 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $8 million due to lower ACE and DPL non-weather related average residential and commercial customer usage, partially offset by higher Pepco residential customer usage.
- A net decrease of $5 million as a result of lower DPL and Pepco Default Electricity Supply rates, partially offset by higher ACE rates.

The aggregate amount of these decreases was partially offset by:

- An increase of $10 million in ACE 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 $2 million due to higher Pepco revenue from transmission enhancement credits.

Total Default Electricity Supply Revenue for the three months ended June 30, 2013 includes a decrease of $7 million in unbilled revenue attributable to ACE's BGS ($4 million decrease in net income), primarily due to lower non-weather related average customer usage during the unbilled revenue period at June 30, 2013 as compared to the corresponding period in 2012. Under the BGS terms approved by the NJBPU, ACE's BGS unbilled revenue is not included in the deferral calculation until it is billed to customers, and therefore has an impact on the results of operations in the period during which it is accrued.

Regulated Gas

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 14	$ 10	$ 4
Commercial and industrial	7	7	—
Transportation and other	3	2	1
Total Regulated Gas Revenue	$ 24	$ 19	$ 5

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	887	597	290
Commercial and industrial	608	368	240
Transportation and other	1,454	1,458	(4)
Total Regulated Gas Sales	2,949	2,423	526

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	115	114	1
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	125	123	2

DPL's natural gas service territory is located in New Castle County, Delaware. Several key industries contribute to the economic base as well as to growth, as follows:

- Commercial activities in the region include banking and other professional services, government, insurance, real estate, shopping malls and stand alone construction.
- Industrial activities in the region include chemical and pharmaceutical.

Regulated Gas Revenue increased by $5 million primarily due to:

- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by an increase in Fuel and Purchased Energy).
- An increase of $2 million due to higher sales primarily as a result of colder weather in 2013 as compared to 2012.
- An increase of $1 million due to higher non-weather related average commercial customer usage.

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 2012.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $27 million primarily due to:

- A decrease of $16 million due to decreased energy services construction activities.
- A decrease of $10 million due to lower generation and capacity revenues attributable to the deactivation of the remaining generating facilities in the second quarter of 2012.

Other Non-Regulated

Other Non-Regulated's operating revenue decreased by $11 million primarily due to the early terminations of cross-border energy lease investments in the third quarter of 2012 and the second quarter of 2013. For further discussion of PHI's cross-border energy lease investments, see Note (8), "Leasing Activities – Investment in Finance Leases Held in Trust," and Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," to the consolidated financial statements of PHI.

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:

	2013	2012	Change
Power Delivery	$447	$458	$ (11)
Pepco Energy Services	35	54	(19)
Corporate and Other	(1)	2	(3)
Total	$481	$514	$ (33)

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 decreased by $11 million primarily due to:

- A decrease of $26 million primarily due to customer migration to competitive suppliers.
- A decrease of $8 million in deferred electricity expense primarily due to lower Pepco Default Electricity Supply revenue rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $4 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.

The aggregate amount of these decreases was partially offset by:

- A net increase of $17 million due to higher average electricity costs under DPL and Pepco Default Electricity Supply contracts, partially offset by lower ACE costs.
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).
- An increase of $3 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $2 million in deferred electricity expense primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $2 million in the cost of purchasing Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales decreased by $19 million primarily due to:

- A decrease of $15 million primarily due to lower energy services construction activity.
- A decrease of $5 million primarily due to lower purchases of fuel attributable to the deactivation of the remaining generation facilities in the second quarter of 2012.

Other Operation and Maintenance

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

	2013	2012	Change
Power Delivery	$217	$219	$ (2)
Pepco Energy Services	10	15	(5)
Other Non-Regulated	2	2	—
Corporate and Other	(16)	(16)	—
Total	$213	$220	$ (7)

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $2 million primarily due to:

- A decrease of $4 million associated with lower maintenance costs.
- A decrease of $3 million in customer service costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $3 million resulting from 2012 deferred cost adjustments associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes in 2012.
- An increase of $1 million in bad debt expenses that are deferred and recoverable.
- An increase of $1 million in environmental remediation costs.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $5 million primarily due to:

- A decrease of $3 million in personnel costs in its energy savings services business primarily due to a reduction in the number of employees in the second half of 2012.
- A decrease of $2 million in contractual costs due to the deactivation of its generating facilities in the second quarter of 2012.

Depreciation and Amortization

Depreciation and Amortization expense increased by $5 million to $116 million in 2013 from $111 million in 2012 primarily due to:

- An increase of $5 million in amortization of MAPP abandonment costs (which is offset in T&D Electric Revenue).
- An increase of $3 million in amortization of regulatory assets primarily related to recoverable storm costs and rate case costs.

The aggregate amount of these increases was partially offset by:

- A decrease of $2 million primarily due to the deactivation of Pepco Energy Services generating facilities in the second quarter of 2012.
- A decrease of $2 million due to lower depreciation rates, partially offset by utility plant additions.

Other Taxes

Other Taxes decreased by $4 million to $101 million in 2013 from $105 million in 2012. The decrease was primarily due to lower sales that resulted in a decrease in utility taxes that are collected and passed through by Power Delivery (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Loss on Early Termination of Finance Leases Held in Trust

During the second quarter of 2013, PHI terminated early its interests in five of its six remaining cross-border energy lease investments and recorded a pre-tax loss, including transaction costs, of $14 million ($9 million after-tax) for the three months ended June 30, 2013 representing the excess of the carrying value of the terminated leases over the net cash proceeds received.

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 New Jersey Societal Benefit Programs 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 $16 million to an expense reduction of $4 million in 2013 as compared to an expense reduction of $20 million in 2012 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Programs revenue rates and lower electricity supply costs.

Impairment Losses

PHI’s operating expenses include impairment losses of $3 million for the three months ended June 30, 2012, associated primarily with its investment in a landfill gas-fired electric generation facility owned and operated by Pepco Energy Services. During the second quarter of 2012, Pepco Energy Services performed a long-lived asset impairment test on the facility as a result of a sustained decline in energy prices, and the facility was written down to its estimated fair value because the future expected cash flows of the facility were not sufficient to provide recovery of the facility’s carrying value.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $7 million to a net expense of $62 million in 2013 from a net expense of $55 million in 2012. The increase reflects a $5 million increase in interest expense primarily associated with higher long-term debt and $2 million associated with lower 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 $3 million to $32 million in 2013 from $29 million in 2012. PHI's consolidated effective tax rates for the three months ended June 30, 2013 and 2012 were 45.7% and 35.4%, respectively. The increase in the effective tax rate primarily resulted from a charge of $6 million in the second quarter of 2013 to reflect a change in estimate associated with state income taxes related to the reduction of the carrying value of PCI's cross-border energy lease investments recorded in the first quarter of 2013.

Discontinued Operations

For the three months ended June 30, 2013 and 2012, Income from Discontinued Operations, Net of Income Taxes, was $4 million and $9 million, respectively. The decrease of $5 million is primarily the result of the wind-down of the Pepco Energy Services retail electric and natural gas supply businesses, partially offset by the net pre-tax gain of $8 million ($5 million after-tax) recorded in the second quarter of 2013 on the assumption by a third party, on April 1, 2013, of all of the rights and obligations of the derivative contracts associated with the retail natural gas supply business.

The following results of operations discussion compares the six months ended June 30, 2013 to the six months ended June 30, 2012. 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:

	2013	2012	Change
Power Delivery	$2,130	$2,039	$ 91
Pepco Energy Services	106	148	(42)
Other Non-Regulated	(365)	27	(392)
Corporate and Other	(6)	(8)	2
Total Operating Revenue	$1,865	$2,206	$ (341)

Power Delivery Business

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

	2013	2012	Change
Regulated T&D Electric Revenue	$ 999	$ 924	$ 75
Default Electricity Supply Revenue	984	986	(2)
Other Electric Revenue	33	31	2
Total Electric Operating Revenue	2,016	1,941	75
Regulated Gas Revenue	97	84	13
Other Gas Revenue	17	14	3
Total Gas Operating Revenue	114	98	16
Total Power Delivery Operating Revenue	$2,130	$2,039	$ 91

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 include 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

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 354	$ 316	$ 38
Commercial and industrial	457	431	26
Transmission and other	188	177	11
Total Regulated T&D Electric Revenue	$ 999	$ 924	$ 75

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	8,282	7,766	516
Commercial and industrial	14,673	14,888	(215)
Transmission and other	122	125	(3)
Total Regulated T&D Electric Sales	23,077	22,779	298

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,641	1,638	3
Commercial and industrial	199	199	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,842	1,839	3

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 services, government, insurance, real estate, shopping malls, casinos, stand alone construction and tourism.
- Industrial activities in the region include chemical, glass, pharmaceutical, steel manufacturing, food processing and oil refining.

Regulated T&D Electric Revenue increased by $75 million primarily due to:

- An increase of $44 million due to distribution rate increases (Pepco in the District of Columbia effective October 2012, and in Maryland effective July 2012; DPL in Maryland and Delaware effective July 2012; and ACE effective November 2012).
- An increase of $9 million primarily due to DPL's Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Fuel and Purchased Energy and Depreciation and Amortization).
- An increase of $8 million primarily due to a rate increase in the New Jersey Societal Benefit Charge (related to the New Jersey Societal Benefit Program, a public interest program for low income customers) effective July 2012 (which is offset in Deferred Electric Service Costs).
- An increase of $6 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $6 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $5 million in transmission revenue primarily attributable to higher rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $5 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset by a corresponding increase in Depreciation and Amortization).
- An increase of $3 million in transmission revenue primarily attributable to higher capacity revenue as a result of expanding Maryland demand-side management programs (which is substantially offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million in transmission revenue primarily attributable to less favorable FERC formula rate true-ups.
- A decrease of $3 million in transmission revenue primarily attributable to a peak-load decrease effective January 2013.
- A decrease of $3 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes), primarily the result of a utility tax rate decrease effective July 2012 that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$661	$672	$ (11)
Commercial and industrial	253	265	(12)
Other	70	49	21
Total Default Electricity Supply Revenue	$984	$986	$ (2)

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

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	6,665	6,560	105
Commercial and industrial	2,479	2,795	(316)
Other	31	29	2
Total Default Electricity Supply Sales	9,175	9,384	(209)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,343	1,399	(56)
Commercial and industrial	126	133	(7)
Other	—	—	—
Total Default Electricity Supply Customers	1,469	1,532	(63)

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

- A decrease of $51 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A net decrease of $10 million as a result of lower Pepco and DPL Default Electricity Supply rates, partially offset by higher ACE rates.

The aggregate amount of these decreases was partially offset by:

- An increase of $37 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $16 million in ACE 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 $4 million due to higher Pepco revenue from transmission enhancement credits.
- An increase of $1 million due to higher DPL non-weather related average residential customer usage, partially offset by lower Pepco and ACE commercial customer usage.

Regulated Gas

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 62	$ 53	$ 9
Commercial and industrial	29	26	3
Transportation and other	6	5	1
Total Regulated Gas Revenue	$ 97	$ 84	$ 13

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	4,959	3,642	1,317
Commercial and industrial	2,669	1,921	748
Transportation and other	3,886	3,587	299
Total Regulated Gas Sales	11,514	9,150	2,364

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	115	114	1
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	125	123	2

Regulated Gas Revenue increased by $13 million primarily due to:

- An increase of $19 million due to higher sales primarily as a result of colder weather during the winter months of 2013 as compared to 2012.
- An increase of $5 million due to higher non-weather related average commercial customer usage.
- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by an increase in Fuel and Purchased Energy).

The aggregate amount of these increases was partially offset by a decrease of $16 million due to a GCR decrease effective November 2012.

Other Gas

Other Gas Revenue increased by $3 million primarily due to higher average prices for off-system sales to electric generators and gas marketers.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $42 million primarily due to:

- A decrease of $25 million due to decreased energy services construction activities.
- A decrease of $17 million due to lower generation and capacity revenues attributable to the deactivation of the remaining generating facilities in the second quarter of 2012.

Other Non-Regulated

Other Non-Regulated's operating revenue decreased by $392 million primarily due to a non-cash charge of $373 million recorded in the first quarter of 2013 to reflect a change in PHI's current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments and the early terminations of cross-border energy lease investments in the third quarter of 2012 and the second quarter of 2013. For further discussion of PHI's cross-border energy lease investments, see Note (8), "Leasing Activities – Investment in Finance Leases Held in Trust," and Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," to the consolidated financial statements of PHI.

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:

	2013	2012	Change
Power Delivery	$1,009	$1,001	$ 8
Pepco Energy Services	75	102	(27)
Corporate and Other	(1)	1	(2)
Total	$1,083	$1,104	$ (21)

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 $8 million primarily due to:

- An increase of $30 million due to higher electricity sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $11 million in deferred electricity expense primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- A net increase of $10 million due to higher average electricity costs under Pepco and DPL Default Electricity Supply contracts, partially offset by lower ACE costs.
- An increase of $7 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $6 million in the cost of purchasing Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $4 million in the cost of gas purchases for off-system sales as a result of higher average gas prices.
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).

The aggregate amount of these increases was partially offset by:

- A decrease of $50 million primarily due to customer migration to competitive suppliers.
- A decrease of $8 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 $6 million in deferred electricity expense primarily due to lower Pepco Default Electricity Supply revenue rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.

Pepco Energy Services

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

- A decrease of $22 million primarily due to lower energy services construction activity.
- A decrease of $6 million due to lower purchases of fuel attributable to the deactivation of the remaining generating facilities in the second quarter of 2012.

Other Operation and Maintenance

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

	2013	2012	Change
Power Delivery	$448	$443	$ 5
Pepco Energy Services	22	29	(7)
Other Non-Regulated	2	2	—
Corporate and Other	(31)	(33)	2
Total	$441	$441	$ —

Power Delivery

Other Operation and Maintenance expense for Power Delivery increased by $5 million primarily due to:

- An increase of $6 million primarily due to incremental preparation and restoration costs associated with a winter storm in March 2013.
- An increase of $4 million in employee-related costs, primarily benefit expenses.
- An increase of $3 million associated with the write-off of disallowed MAPP and associated transmission project costs.
- An increase of $3 million resulting from 2012 deferred cost adjustments associated with DPL Default Electricity Supply. The deferred costs adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes in 2012.
- An increase of $1 million in environmental remediation costs.

The aggregate amount of these increases was partially offset by:

- A decrease of $6 million in other customer service costs.
- A decrease of $4 million associated with lower maintenance costs.
- A decrease of $3 million due to the deferral of certain customer service costs incurred in 2011 and 2012 that had been previously charged to Other Operation and Maintenance expense. The deferral was recorded in accordance with an MPSC order issued in January 2013 authorizing the establishment of a regulatory asset for the recovery of these costs.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $7 million primarily due to:

- A decrease of $4 million in personnel costs in its energy savings services business primarily due to a reduction in the number of employees in the second half of 2012.
- A decrease of $3 million in contractual costs due to the deactivation of its generating facilities in the second quarter of 2012.

Depreciation and Amortization

Depreciation and Amortization expense increased by $7 million to $228 million in 2013 from $221 million in 2012 primarily due to:

- An increase of $5 million in amortization of MAPP abandonment costs (which is offset in T&D Electric Revenue).
- An increase of $5 million in amortization of regulatory costs related to recoverable storm costs and rate case costs.
- An increase of $4 million in amortization of regulatory assets primarily associated with EmPower Maryland (a Maryland demand-side management program for Pepco and DPL) surcharge rate increases effective February 2012 and expanding demand-side management programs (which are substantially offset by corresponding increases in Regulated T&D Electric Revenue).
- An increase of $3 million in amortization of stranded costs primarily as the result of higher revenue due to higher sales for the ACE Transition Bond Charge and Market Transition Charge Tax (revenue ACE receives and pays to ACE Funding to recover income taxes associated with Transition Bond Charge revenue), which is partially offset in Default Electricity Supply Revenue.

The aggregate amount of these increases was partially offset by:

- A decrease of $6 million primarily due to the deactivation of Pepco Energy Services generating facilities in the second quarter of 2012.
- A decrease of $4 million due to lower depreciation rates, partially offset by utility plant additions.
- A decrease of $2 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Other Taxes

Other Taxes decreased by $3 million to $206 million in 2013 from $209 million in 2012. The decrease was primarily due to lower sales that resulted in a decrease in utility taxes that are collected and passed through by Power Delivery (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Loss on Early Termination of Finance Leases Held in Trust

During the second quarter of 2013, PHI terminated early its interests in five of its six remaining cross-border energy lease investments and recorded a pre-tax loss, including transaction costs, of $14 million ($9 million after-tax) for the six months ended June 30, 2013 representing the excess of the carrying value of the terminated leases over the net cash proceeds received.

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 New Jersey Societal Benefit Programs 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 $32 million to an expense reduction of $3 million in 2013 as compared to an expense reduction of $35 million in 2012 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Programs revenue rates and lower electricity supply costs.

Impairment Losses

PHI's operating expenses include impairment losses of $3 million for the six months ended June 30, 2012, associated primarily with its investment in a landfill gas-fired electric generation facility owned and operated by Pepco Energy Services. During the second quarter of 2012, Pepco Energy Services performed a long-lived asset impairment test on the facility as a result of a sustained decline in energy prices, and the facility was written down to its estimated fair value because the future expected cash flows of the facility were not sufficient to provide recovery of the facility's carrying value.

<u>Other Income (Expenses)</u>

Other Expenses (which are net of Other Income) increased by $9 million to a net expense of $121 million in 2013 from a net expense of $112 million in 2012. The increase reflects a $7 million increase in interest expense primarily associated with higher long-term debt and $2 million associated with lower income related to AFUDC that is applied to capital projects.

<u>Income Tax Expense</u>

PHI's income tax expense increased by $129 million to $167 million in 2013 from $38 million in 2012. PHI's consolidated effective tax rates for the six months ended June 30, 2013 and 2012 were (74.2)% and 25.2%, respectively.

The negative effective tax rate for the six months ended June 30, 2013 occurred as a result of recording $70 million of changes in estimates and interest related to uncertain and effectively settled tax positions, primarily associated with the cross-border energy lease investments (as further discussed in Note (8), "Leasing Activities," to the consolidated financial statements of PHI included herein) and the recognition of a $64 million charge primarily for the tax consequences associated with PHI's change in intent regarding foreign investment opportunities available at the end of the full lease terms of the cross-border energy lease investments.

The negative effective tax rate further resulted from the establishment of valuation allowances of $101 million in the first quarter of 2013 against certain deferred tax assets in PHI's Other Non-Regulated segment. 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 both Consolidated Edison's cross-border lease transaction (as discussed in Note (8), "Leasing Activities," to the consolidated financial statements of PHI included herein) and another taxpayer's structured transactions, (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 represents 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 will 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.

In 2012, PHI recorded tax benefits of $10 million for changes in estimates and interest related to uncertain and effectively settled tax positions primarily due to the effective settlement with the IRS in the first quarter of 2012 with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position in Pepco.

Discontinued Operations

For the six months ended June 30, 2013 and 2012, Income from Discontinued Operations, Net of Income Taxes, was $4 million and $17 million, respectively. The decrease of $13 million is primarily the result of the wind-down of the Pepco Energy Services retail electric and natural gas supply businesses, partially offset by the net pre-tax gain of $4 million ($2 million after-tax) recorded in the six months ended June 30, 2013 as a result of the assumption by a third party, on April 1, 2013, of all of the rights and obligations of the remaining retail energy supply customer contracts, and the associated supply obligations, gas inventory and derivative contracts. The net pre-tax gain of $4 million is comprised of the pre-tax gain recorded on the completion of the transaction of $8 million ($5 million after-tax), partially offset by the pre-tax loss of $4 million ($2 million after-tax) recorded in the first quarter of 2013 to reflect the determination by PHI, when the agreements were entered into, that the hedged forecasted purchases of supply for retail natural gas customers were probable not to occur and accordingly, that the derivatives no longer qualified for cash flow hedge accounting. As a result, the derivative losses that had been previously recorded in Accumulated Other Comprehensive Loss were reclassified into income in the first quarter of 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, 2013, PHI's current assets on a consolidated basis totaled $1.4 billion and its consolidated current liabilities totaled $2.4 billion, resulting in a working capital deficit of $1.0 billion. PHI expects the working capital deficit at June 30, 2013 to be funded during 2013 in part through cash flows from operations, proceeds from the early termination of PHI's cross-border energy lease investments and from the issuance of long-term debt. At December 31, 2012, PHI's current assets on a consolidated basis totaled $1.3 billion and its current liabilities totaled $2.5 billion, for a working capital deficit of $1.2 billion. The decrease of $248 million in the working capital deficit from December 31, 2012 to June 30, 2013 was primarily due to a decrease in short-term debt, the repayment of which was primarily funded with cash received from the early terminations of the cross-border energy leases, partially offset by an increase in liabilities and accrued interest related to uncertain tax positions.

At June 30, 2013, PHI's consolidated cash and cash equivalents totaled $15 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 $20 million. At December 31, 2012, PHI's consolidated cash and cash equivalents totaled $25 million, which consisted of cash and uncollected funds but excluded current Restricted Cash Equivalents that totaled $10 million.

A 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, 2013 (millions of dollars)							
Type	**PHI Parent**	**Pepco**	**DPL**	**ACE**	**ACE Funding**	**Pepco Energy Services**	**PCI**	**PHI Consolidated**
Variable Rate Demand Bonds	$ —	$ —	$105	$18	$ —	$ —	$ —	$ 123
Commercial Paper	114	—	109	46	—	—	—	269
Total Short-Term Debt	$ 114	$ —	$214	$64	$ —	$ —	$ —	$ 392
Current Portion of Long-Term Debt and Project Funding	$ —	$ 375	$250	$69	$ 40	$ 11	$ 11	$ 756

	As of December 31, 2012 (millions of dollars)						
Type	**PHI Parent**	**Pepco**	**DPL**	**ACE**	**ACE Funding**	**Pepco Energy Services**	**PHI Consolidated**
Variable Rate Demand Bonds	$ —	$ —	$105	$ 23	$ —	$ —	$ 128
Commercial Paper	264	231	32	110	—	—	637
Term Loan Agreement	200	—	—	—	—	—	200
Total Short-Term Debt	$ 464	$ 231	$137	$133	$ —	$ —	$ 965
Current Portion of Long-Term Debt and Project Funding	$ —	$ 200	$250	$ 69	$ 39	$ 11	$ 569

Commercial Paper

PHI, Pepco, DPL and ACE maintain commercial paper programs to address short-term liquidity needs. As of June 30, 2013, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $250 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, DPL and ACE had $114 million, $109 million and $46 million, respectively, of commercial paper outstanding at June 30, 2013. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2013 was 0.71%, 0.38%, 0.32% and 0.34%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the six months ended June 30, 2013 was five, seven, two and four days, respectively.

Financing Activity During the Three Months Ended June 30, 2013

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 London Interbank Offered Rate (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 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.

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, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.95%, 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, 2013.

Bond Payments

In April 2013, 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 Redemptions

On May 30, 2013, ACE redeemed, prior to maturity, at par plus accrued interest, all $4.4 million outstanding weekly rate pollution control revenue refunding bonds due 2017, issued by the Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit.

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.

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. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

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 (10), "Debt," to the consolidated financial statements of PHI.

Cash and Credit Facility Available as of June 30, 2013

	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	269	114	155
Remaining Credit Facility Available	1,229	634	595
Cash Invested in Money Market Funds and on hand (a)	1	1	—
Total Cash and Credit Facility Available	$ 1,230	$ 635	$ 595

(a) Cash and Cash Equivalents reported on the PHI consolidated balance sheet totaled $15 million, of which $1 million was invested in money market funds, and the balance was held in cash and uncollected funds.

Financing Activities Subsequent to June 30, 2013

Bond Payments

In July 2013, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $2 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 quarter of 2013, PHI terminated early its interest in five of the six remaining lease investments. PHI received aggregate net cash proceeds of $693 million (net of aggregate termination payments of $1.4 billion used to retire the non-recourse debt associated with the terminated leases) and recorded a pre-tax loss, including transaction costs, of approximately $14 million in the second quarter of 2013, 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 were used to repay borrowings utilized to fund the advanced payment discussed above.

During July 2013, PHI entered into an agreement with the lessee of the last remaining PHI lease investment which provides for the early termination of such lease investment. Upon closing, on July 26, 2013, PHI received aggregate net cash proceeds of $180 million (net of aggregate termination payments of $665 million used to retire the non-recourse debt associated with the terminated leases) and expects to record in the third quarter of 2013 a pre-tax gain, including transaction costs, of approximately $11 million ($7 million after-tax), representing the excess of the net cash proceeds received over the carrying value of the terminated leases. The aggregate financial impact upon completion of the early terminations of the cross-border energy lease investments in 2013 is expected to be a pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax).

Pension and Postretirement Benefit Plans

Pension benefits are provided under PHI's non-contributory retirement plan (the PHI Retirement Plan), a defined benefit pension plan that covers substantially all employees of Pepco, DPL and ACE and certain employees of other PHI subsidiaries. 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.

PHI satisfied the minimum required contribution rules under the Pension Protection Act in 2012 and 2011, and anticipates that it will satisfy the requirement in 2013. In the first quarter of 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $20 million, $10 million and $30 million, respectively. PHI made an additional discretionary tax-deductible contribution to the PHI Retirement Plan of approximately $60 million during the second quarter of 2013. In the first quarter of 2012, Pepco, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $85 million, $85 million and $30 million, respectively, which brought the PHI Retirement Plan assets to at least the funding target level for 2012 under the Pension Protection Act.

Based on the results of the 2012 actuarial valuation, PHI's net periodic pension and other postretirement benefit costs were $110 million in 2012 versus $94 million in 2011. The current estimate of benefit cost for 2013 is $107 million. The utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and other postretirement benefit costs. Approximately 30% of net periodic pension and other postretirement benefit costs are capitalized. PHI estimates that its net periodic pension and other postretirement benefit expense will be approximately $75 million in 2013, as compared to $77 million in 2012.

Other Postretirement Benefit Plan Amendment

In July 2013, PHI approved an amendment to its retiree medical plans that will be effective on January 1, 2014. As a result of the amendment, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013 and recorded a prior service credit of approximately $100 million, which will be amortized over approximately ten years. The remeasurement is expected to result in a $13 million reduction in net periodic benefit cost for other postretirement benefits to be recognized in the second half of 2013 as compared to the net periodic benefit cost for other postretirement benefits recognized in the first half of 2013.

Cash Flow Activity

PHI's cash flows for the six months ended June 30, 2013 and 2012 are summarized below:

	Cash (Use) Source		
	2013	2012	Change
		(millions of dollars)	
Operating Activities	$(35)	$ 124	$(159)
Investing Activities	83	(560)	643
Financing Activities	(58)	366	(424)
Net (decrease) increase in cash and cash equivalents	$(10)	$ (70)	$ 60

Operating Activities

Cash flows from operating activities during the six months ended June 30, 2013 and 2012 are summarized below:

	Cash (Use) Source		
	2013	2012	Change
		(millions of dollars)	
Net (loss) income from continuing operations	$(392)	$ 113	$(505)
Non-cash adjustments to net income	600	190	410
Pension contributions	(120)	(200)	80
Advanced payment made to taxing authority	(242)	—	(242)
Changes in cash collateral related to derivative activities	28	53	(25)
Changes in other assets and liabilities	94	(32)	126
Changes in Pepco Energy Services net assets held for disposition	(3)	—	(3)
Net cash (used by) from operating activities	$ (35)	$ 124	$(159)

Net cash from operating activities decreased $159 million for the six months ended June 30, 2013, compared to the same period in 2012. The decrease was primarily due to a decrease in net income of $505 million and a $242 million advanced payment to the IRS for estimated additional taxes and related interest, partially offset by an $80 million decrease in pension contributions and a $410 million increase in non-cash adjustments to net income primarily associated with the cross-border energy lease investments.

Investing Activities

Cash flows from investing activities during the six months ended June 30, 2013 and 2012 are summarized below:

	Cash Source (Use)		
	2013	2012	Change
	(millions of dollars)		
Investment in property, plant and equipment	$(616)	$(589)	$ (27)
Department of Energy (DOE) capital reimbursement awards received	12	22	(10)
Proceeds from early termination of finance leases held in trust	693	—	693
Changes in restricted cash equivalents	(8)	2	(10)
Net other investing activities	2	5	(3)
Net cash from (used by) investing activities	$ 83	$(560)	$ 643

Net cash from investing activities increased $643 million for the six months ended June 30, 2013, compared to the same period in 2012. The increase was primarily due to proceeds from the early termination of cross-border lease investments.

Financing Activities

Cash flows from financing activities during the six months ended June 30, 2013 and 2012 are summarized below:

	Cash (Use) Source		
	2013	2012	Change
	(millions of dollars)		
Dividends paid on common stock	$(134)	$(123)	$ (11)
Common stock issued for the Dividend Reinvestment Plan and employee-related compensation	27	28	(1)
Issuances of common stock	324	—	324
Issuances of long-term debt	350	450	(100)
Reacquisitions of long-term debt	(19)	(122)	103
Repayments of short-term debt, net	(373)	(57)	(316)
Issuances of term loan	250	200	50
Repayments of term loan	(450)	—	(450)
Cost of issuances	(16)	(7)	(9)
Net other financing activities	(17)	(3)	(14)
Net cash (used by) from financing activities	$ (58)	$ 366	$(424)

Net cash from financing activities decreased $424 million for the six months ended June 30, 2013, compared to the same period in 2012. The decrease was primarily due to a net decrease of $400 million in term loans and an increase of $316 million of short-term debt repayments, partially offset by issuances of common stock of $324 million 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, 2013 and 2012 are summarized below:

	Issuances	
	2013	2012
	(millions of dollars)	
Pepco		
4.15% First mortgage bonds due 2043	$ 250	$ —
3.05% First mortgage bonds due 2022	—	200
	250	200
DPL		
4.00% First mortgage bonds due 2042	—	250
	—	250
ACE		
Term loan due 2014	100	—
	100	—
	$ 350	$ 450

	Reacquisitions	
	2013	2012
	(millions of dollars)	
Pepco		
5.375% Tax-exempt bonds due 2024(a)	$ —	$ 38
	—	38
DPL		
0.75% Tax-exempt bonds due 2026(a)	—	35
1.80% Tax-exempt bonds due 2025	—	15
2.30% Tax-exempt bonds due 2028	—	16
	—	66
ACE		
Securitization bonds due 2012-2013	19	18
	19	18
	$ 19	$ 122

(a) These bonds were secured by an outstanding series of collateral first mortgage bonds issued by the utility, which had maturity dates, optional and mandatory redemption provisions, interest rates and interest payment dates that are identical to the terms of the tax-exempt bonds. The collateral first mortgage bonds were automatically redeemed simultaneously with the redemption of the tax-exempt bonds.

Changes in Short-Term Debt

As of June 30, 2013, PHI had a total of $269 million of commercial paper outstanding as compared to $637 million of commercial paper outstanding as of December 31, 2012.

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 made 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, 2013 were $616 million, of which $258 million was incurred by Pepco, $164 million was incurred by DPL, $141 million was incurred by ACE, $1 million by Pepco Energy Services and $52 million for 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 2012 Form 10-K, PHI presented its projected capital expenditures for the five-year period 2013 through 2017. There have been no changes in PHI's projected capital expenditures from those presented in the 2012 Form 10-K except for a reduction of approximately $150 million to more closely align ACE's spending in New Jersey to the revenue ACE will receive following the June 21, 2013 NJBPU approval of the stipulation of settlement on the ACE petition to increase electric base rates. 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 each of PHI's utility subsidiaries to install smart meters, further automate their electric distribution systems and enhance their communications infrastructure, which is referred to as the smart grid.

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 expenses associated with direct load control and other Pepco and ACE programs. During the six months ended June 30, 2013, Pepco and ACE received award payments of $16 million and $1 million, respectively. The cumulative award payments received by Pepco and ACE as of June 30, 2013 were $131 million and $15 million, respectively.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

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

For a discussion of PHI's third party guarantees, indemnifications, obligations and off-balance sheet arrangements, see Note (15), "Commitments and Contingencies," to the consolidated financial statements of PHI.

Dividends

On July 25, 2013, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable September 30, 2013 to stockholders of record on September 10, 2013. PHI had approximately $555 million and $1,077 million of retained earnings free of restrictions at June 30, 2013 and December 31, 2012, 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, 2013, 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 $103 million. Of this amount, $4 million is attributable to derivatives, normal purchase and normal sale contracts, collateral, and other contracts under master netting agreements as described in Note (13), "Derivative Instruments and Hedging Activities" to the consolidated financial statements of PHI. The remaining $99 million 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.

Regulatory and Other Matters

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 (MW) 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 the Contract EDCs will recover the associated costs through surcharges on their 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. These circuit court appeals were consolidated in the Circuit Court for Baltimore City and stayed pending the issuance of a final order from the MPSC approving the form of contract.

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, in amounts proportional to their relative SOS loads, with the winning bidder. The MPSC stated that the order, which approves timely and complete recovery by the

Contract EDCs of the costs associated with the contract, constitutes a binding commitment that shall not be subject to future modification or rescission by the MPSC. Despite this commitment from the MPSC, Pepco and DPL believe that the attempt by the MPSC to bind a future commission in this manner may be subject to legal challenge, which challenge, if successful, could impair the right of Pepco and DPL to recover their costs in the future. In addition, the MPSC excluded from the contract a provision that Pepco and DPL believe is important to mitigate their financial risk because the provision, had it been included, would have required Pepco and DPL to make payments to the winning bidder under the contract only to the extent they were able to recover those costs (for example, Pepco and DPL believe the excluded provision would have protected them in the event a significant number of their SOS customers elect to buy their energy from alternative energy suppliers). In light of the issuance of the MPSC's final order, the previously filed appeals of the MPSC's actions in this case before the circuit court are now proceeding. On June 4, 2013, Pepco and DPL entered into the contract in accordance with the terms of the MPSC's order; however, under the contract's own terms, it will not become effective, if at all, until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

PHI believes that Pepco and DPL may be required to account for their proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because they would recover any payments under the contract from SOS customers. Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, PHI estimates that Pepco and DPL would be required to record an aggregate derivative liability ranging from $55 million to $70 million with an offsetting regulatory asset in a like amount. These estimates and other assumptions made may change prior to the time that the contract becomes effective, if at all. PHI, Pepco, and DPL have concluded that any accounting for this contract would not be required until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

PHI, Pepco and DPL are in the process of determining (i) the extent of the negative effect that the contract for new generation 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 each of their debt issuances, (ii) the effect on Pepco's and DPL's ability to recover their associated costs of the contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

For a discussion of other regulatory matters, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Legal Proceedings

For a discussion of legal proceedings, see Note (15), "Commitments and Contingencies," 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' 2012 Form 10-K. There have been no material changes to PHI's critical accounting policies as disclosed in the 2012 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 significant 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 has a population of approximately 2.2 million. As of June 30, 2013, 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.

Reliability Enhancement

Since 2010, Pepco has implemented comprehensive reliability enhancement plans in its service territory. These reliability enhancement plans include various initiatives to improve electrical system reliability, such as:

- the identification and upgrading of under-performing feeder lines;
- the addition of new facilities to support load;
- the installation of distribution automation systems on both the overhead and underground network systems;

- the rejuvenation and replacement of underground residential cables;
- selective undergrounding of portions of existing above-ground primary feeder lines, where appropriate to improve reliability;
- improvements to substation supply lines; and
- enhanced vegetation management.

Smart Grid

Pepco is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, 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."

Mitigation of Regulatory Lag

An important factor in the ability of Pepco to earn its authorized rate of return is the willingness of applicable public service commissions to adequately recognize forward-looking costs in its rate structure in order to address the shortfall in revenues 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 its investment in the rate base and its operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, Pepco's District of Columbia and Maryland base rate case filings in 2011 each included a request for approval from the applicable state regulatory commissions of (i) a RIM to recover reliability-related capital expenditures incurred between base rate cases and (ii) the use by the applicable utility of fully forecasted test years in future base rate cases. In June 2012, the MPSC rejected Pepco's request to implement the RIM and did not endorse the use by Pepco of fully forecasted test years in future rate cases. However, the MPSC did permit an adjustment to the rate base of Pepco to reflect the actual cost of reliability plant additions outside the test year. In the District of Columbia, the DCPSC denied Pepco's request for approval of a RIM in 2012, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases.

Pepco will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag. There can be no assurance that any attempts by Pepco to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, Pepco plans to file rate cases at least annually in an effort to align more closely the revenue and cash flow levels with other operation and maintenance spending and capital investments. Pepco filed its electric distribution base rate case in March 2013 in the District of Columbia, and expects to file its next electric distribution base rate case in Maryland by the end of 2013. In Maryland, Pepco included a proposed three-year Grid Resiliency Charge rider intended to reduce regulatory lag. In July 2013, the MPSC issued an order that only partially approved the proposed Grid Resiliency Charge. See Note (6), "Regulatory Matters – Rate Proceedings," to the financial statements of Pepco for more information about these base rate cases. On July 26, 2013, Pepco filed a notice of appeal of this MPSC order. Furthermore, Pepco is continuing to review the impact of this order and consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to Pepco.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. As of December 31, 2012, Pepco's total costs related to the MAPP project were approximately $64 million. In a 2008 FERC order approving incentives for the MAPP project, FERC authorized the recovery of prudently incurred abandoned costs in connection with the MAPP project. Consistent with this order, in December 2012, PHI submitted a filing to FERC seeking recovery of $50 million of abandoned MAPP costs. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by Pepco to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. Pepco believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. In April 2013, PHI filed a rehearing request on behalf of Pepco of the February 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that PHI is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. Pepco cannot predict when a final FERC decision in this proceeding will be issued.

As of December 31, 2012, Pepco had placed in service $11 million of its total capital expenditures with respect to the MAPP project, which represented upgrades of existing substation assets that were expected to support the MAPP transmission line, transferred approximately $3 million of materials to inventories, for use on other projects, and reclassified the remaining $50 million of capital expenditures to a regulatory asset. During the first quarter of 2013, Pepco further transferred an additional $2 million of materials to inventories, for use on other projects, and expensed $1 million of abandoned costs as a result of FERC's disallowance noted above. During the second quarter of 2013, Pepco further transferred an additional $3 million of materials to inventories, for use on other projects, resulting in a regulatory asset of $44 million as of June 30, 2013. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. Pepco intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

Transmission ROE Challenge

On February 27, 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, 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 Pepco provides. The complainants claim to 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. On April 3, 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.

Results of Operations

The following results of operations discussion compares the six months ended June 30, 2013 to the six months ended June 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$566	$545	$ 21
Default Electricity Supply Revenue	362	360	2
Other Electric Revenue	18	16	2
Total Operating Revenue	$946	$921	$ 25

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 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 include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 163	$ 154	$ 9
Commercial and industrial	319	314	5
Transmission and other	84	77	7
Total Regulated T&D Electric Revenue	$ 566	$ 545	$ 21

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	3,806	3,598	208
Commercial and industrial	8,630	8,804	(174)
Transmission and other	75	78	(3)
Total Regulated T&D Electric Sales	12,511	12,480	31

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	719	716	3
Commercial and industrial	74	74	—
Transmission and other	—	—	—
Total Regulated T&D Electric Customers	793	790	3

Regulated T&D Electric Revenue increased by $21 million primarily due to:

- An increase of $16 million due to distribution rate increases in the District of Columbia effective October 2012 and in Maryland effective July 2012.
- An increase of $4 million in transmission revenue primarily attributable to higher rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $3 million in transmission revenue primarily attributable to higher capacity revenue as a result of expanding Maryland demand-side management programs (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $3 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset by a corresponding increase in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million in transmission revenue primarily attributable to a less favorable FERC formula rate true-up.
- A decrease of $3 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a utility tax rate decrease effective July 2012 that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$ 252	$ 252	$ —
Commercial and industrial	101	103	(2)
Other	9	5	4
Total Default Electricity Supply Revenue	$ 362	$ 360	$ 2

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	2,899	2,876	23
Commercial and industrial	1,322	1,294	28
Other	11	4	7
Total Default Electricity Supply Sales	4,232	4,174	58

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	558	583	(25)
Commercial and industrial	43	44	(1)
Other	—	—	—
Total Default Electricity Supply Customers	601	627	(26)

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

- An increase of $14 million due to higher sales as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $4 million primarily due to higher revenue from transmission enhancement credits.

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million as a result of lower Default Electricity Supply rates.
- A decrease of $6 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $2 million due to lower non-weather related average commercial customer usage.

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:

	2013	2012
Sales to District of Columbia customers	25%	24%
Sales to Maryland customers	40%	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 $4 million to $349 million in 2013 from $345 million in 2012 primarily due to:

- An increase of $12 million due to higher electricity sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $4 million due to higher average electricity costs under Default Electricity Supply contracts.

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million primarily due to customer migration to competitive suppliers.
- A decrease of $5 million in deferred electricity expense primarily due to lower Default Electricity Supply revenue rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $7 million to $197 million in 2013 from $204 million in 2012 primarily due to:

- A decrease of $6 million associated with lower tree trimming and maintenance costs.
- A decrease of $4 million in other customer service costs.
- A decrease of $3 million due to the deferral of certain customer service costs incurred in 2011 and 2012 that had been previously charged to Other Operation and Maintenance expense. The deferral was recorded in accordance with an MPSC order issued in January 2013, authorizing the establishment of a regulatory asset for the recovery of these costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $3 million in incremental preparation and restoration costs associated with a winter storm in March 2013.
- An increase of $3 million in employee-related costs, primarily benefit expenses.
- An increase of $1 million associated with the write-off of disallowed MAPP costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $1 million to $96 million in 2013 from $95 million in 2012 primarily due to:

- An increase of $3 million in amortization of regulatory assets primarily associated with an EmPower Maryland surcharge rate increase effective February 2012 and expanding demand-side management programs (which are substantially offset by corresponding increases in Regulated T&D Electric Revenue).
- An increase of $3 million in amortization of MAPP abandonment costs (which is offset in T&D Electric Revenue).
- An increase of $3 million in amortization of regulatory costs related to recoverable storm costs and rate case costs.

The aggregate amount of these increases was partially offset by a decrease of $7 million primarily due to lower depreciation rates, partially offset by plant additions.

Other Taxes

Other Taxes decreased by $5 million to $177 million in 2013 from $182 million in 2012. The decrease was primarily due to decreases in the Montgomery County, Maryland utility taxes that are collected and passed through by Pepco (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $4 million to a net expense of $45 million in 2013 from a net expense of $41 million in 2012. The increase was primarily due to an increase of $5 million in interest expense primarily associated with higher long-term debt.

Income Tax Expense

Pepco's income tax expense increased by $19 million to $22 million in 2013 from $3 million in 2012. Pepco's effective tax rates for the six months ended June 30, 2013 and 2012 were 26.8% and 5.6%, respectively. The increase in the effective tax rate primarily resulted from 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 has determined that it can 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 a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $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 Pepco recording a $5 million interest benefit in the first quarter of 2013.

In 2012, Pepco recorded tax benefits of $11 million for changes in estimates and interest related to uncertain and effectively settled tax positions primarily due to the effective settlement with the IRS with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position.

Capital Requirements

Capital Expenditures

Pepco's capital expenditures for the six months ended June 30, 2013 were $258 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 2012 Form 10-K, Pepco presented its projected capital expenditures for the five-year period 2013 through 2017. There have been no changes in Pepco's projected capital expenditures from those presented in the 2012 Form 10-K. 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 programs undertaken by Pepco to install smart meters, further automate electric distribution systems and enhance Pepco's communications infrastructure, which is referred to as the smart grid.

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 expenses associated with direct load control and other programs. For the six months ended June 30, 2013, Pepco received award payments of $16 million. Cumulative award payments received by Pepco as of June 30, 2013 were $131 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 Delaware and portions of Maryland. DPL also provides Default Electricity Supply. DPL's electricity distribution service territory covers approximately 5,000 square miles and has a population of approximately 1.4 million. As of June 30, 2013, approximately 65% of delivered electricity sales were to Delaware customers and approximately 35% 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 has 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 comparable revenue decoupling mechanism for DPL electricity and natural gas customers in Delaware is under consideration by the DPSC. 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.

Smart Grid

DPL is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, 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."

Mitigation of Regulatory Lag

An important factor in the ability of DPL to earn its authorized rate of return is the willingness of applicable public service commissions to adequately recognize forward-looking costs in its rate structure in order to address the shortfall in revenues 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 its investment in the rate base and its operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, DPL's Delaware and Maryland base rate case filings in 2011 each included a request for approval from the applicable state regulatory commissions of (i) a RIM to recover reliability-related capital expenditures incurred between base rate cases and (ii) the use by the applicable utility of fully forecasted test years in future base rate cases. In June 2012, the MPSC rejected DPL's requests to implement the RIM and did not endorse the use by DPL of fully forecasted test years in future rate cases. However, the MPSC did permit an adjustment to the rate base of DPL to reflect the actual cost of reliability plant additions outside the test year. In Delaware, a settlement agreement approved by the DPSC in DPL's electric distribution base rate case did not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it did provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag.

DPL will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag. There can be no assurance that any attempts by DPL to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, DPL plans to file rate cases at least annually in an effort to align more closely the revenue and cash flow levels with other operation and maintenance spending and capital investments. DPL filed electric distribution base rate cases in both Delaware and Maryland in March 2013, and filed a natural gas distribution case in December 2012. In DPL's electric distribution base rate case filed in Maryland, DPL included a proposed three-year Grid Resiliency Charge rider intended to reduce regulatory lag. See Note (7), "Regulatory Matters – Rate Proceedings," to the financial statements of DPL for more information about these base rate cases.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. As of December 31, 2012, DPL's total costs related to the MAPP project were approximately $38 million. In a 2008 FERC order approving incentives for the MAPP project, FERC authorized the recovery of prudently incurred abandoned costs in connection with the MAPP project. Consistent with this order, in December 2012, PHI submitted a filing to FERC seeking recovery of $38 million of abandoned MAPP costs. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by DPL to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. DPL believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. In April 2013, PHI filed a rehearing request on behalf of DPL of the February 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that DPL is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. DPL cannot predict when a final FERC decision in this proceeding will be issued.

As of December 31, 2012, DPL had reclassified all $38 million of capital expenditures with respect to the MAPP project to a regulatory asset. During the first quarter or 2013, DPL expensed $1 million of prudently incurred abandoned costs as a result of FERC's disallowance noted above, resulting in a regulatory asset of $37 million as of June 30, 2013. The regulatory asset includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. DPL intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land and land rights.

Transmission ROE Challenge

On February 27, 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, Pepco 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 DPL provides. The complainants claim to 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. On April 3, 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.

Results of Operations

The following results of operations discussion compares the six months ended June 30, 2013 to the six months ended June 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Electric Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$243	$208	$ 35
Default Electricity Supply Revenue	272	279	(7)
Other Electric Revenue	7	7	—
Total Electric Operating Revenue	$522	$494	$ 28

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 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 include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 112	$ 95	$ 17
Commercial and industrial	70	59	11
Transmission and other	61	54	7
Total Regulated T&D Electric Revenue	$ 243	$ 208	$ 35

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	2,561	2,308	253
Commercial and industrial	3,628	3,627	1
Transmission and other	24	25	(1)
Total Regulated T&D Electric Sales	6,213	5,960	253

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	444	441	3
Commercial and industrial	60	60	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	505	502	3

Regulated T&D Electric Revenue increased by $35 million primarily due to:

- An increase of $16 million due to distribution rate increases in Maryland and in Delaware effective July 2012.
- An increase of $9 million primarily due to DPL's Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $6 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $3 million due to higher sales as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $2 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset by a corresponding increase in Depreciation and Amortization).
- An increase of $1 million in transmission revenue primarily attributable to a higher rate effective June 1, 2013 related to increases in transmission plant investment and operating expenses.

The aggregate amount of these increases was partially offset by a decrease of $3 million in transmission revenue primarily attributable to a less favorable FERC formula rate true- up.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$ 211	$ 211	$ —
Commercial and industrial	55	63	(8)
Other	6	5	1
Total Default Electricity Supply Revenue	$ 272	$ 279	$ (7)

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	2,256	2,128	128
Commercial and industrial	663	891	(228)
Other	13	15	(2)
Total Default Electricity Supply Sales	2,932	3,034	(102)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	399	409	(10)
Commercial and industrial	39	41	(2)
Other	—	—	—
Total Default Electricity Supply Customers	438	450	(12)

Default Electricity Supply Revenue decreased by $7 million primarily due to:

- A decrease of $19 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $9 million as a result of lower Default Electricity Supply rates.

The aggregate amount of these decreases was partially offset by:

- An increase of $14 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $6 million due to higher non-weather related average residential 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:

	2013	2012
Sales to Delaware customers	44%	49%
Sales to Maryland customers	52%	55%

Natural Gas Operating Revenue

	2013	2012	Change
Regulated Gas Revenue	$ 97	$84	$ 13
Other Gas Revenue	17	14	3
Total Natural Gas Operating Revenue	$114	$98	$ 16

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

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 62	$ 53	$ 9
Commercial and industrial	29	26	3
Transportation and other	6	5	1
Total Regulated Gas Revenue	$ 97	$ 84	$ 13

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	4,959	3,642	1,317
Commercial and industrial	2,669	1,921	748
Transportation and other	3,886	3,587	299
Total Regulated Gas Sales	11,514	9,150	2,364

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	115	114	1
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	125	123	2

Regulated Gas Revenue increased by $13 million primarily due to:

- An increase of $19 million due to higher sales primarily as a result of colder weather during the winter months of 2013 as compared to 2012.
- An increase of $5 million due to higher non-weather related average commercial customer usage.
- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by a decrease in Fuel and Purchased Energy).

The aggregate amount of these increases was partially offset by a decrease of $16 million due to a GCR decrease effective November 2012.

Other Gas

Other Gas Revenue increased by $3 million primarily due to higher average prices for off-system sales to electric generators and gas marketers.

Operating Expenses

Purchased Energy

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 $15 million to $280 million in 2013 from $265 million in 2012 primarily due to:

- An increase of $12 million due to higher electricity sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $11 million in deferred electricity expense primarily due a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $8 million due to higher average electricity costs under Default Electricity Supply contracts.
- An increase of $6 million in the cost of purchasing 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 $20 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 $7 million to $69 million in 2013 from $62 million in 2012 primarily due to:

- An increase of $7 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $4 million in the cost of gas purchases for off-system sales as a result of higher average gas prices.
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.

Other Operation and Maintenance

Other Operation and Maintenance expense increased by $5 million to $132 million in 2013 from $127 million in 2012 primarily due to:

- An increase of $3 million resulting from 2012 deferred cost adjustments associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes in 2012.
- An increase of $2 million associated with the write-offs of disallowed MAPP and associated transmission project costs.

- An increase of $1 million in incremental preparation and restoration costs associated with a winter storm in March 2013.
- An increase of $1 million in employee-related costs, primarily benefit expenses.

The aggregate amount of these increases was partially offset by:

- A decrease of $2 million in customer service costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $3 million to $52 million in 2013 from $49 million in 2012 primarily due to:

- An increase of $2 million in amortization of MAPP abandonment costs (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $1 million in amortization of regulatory assets primarily associated with an EmPower Maryland surcharge rate increase effective February 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $1 million in amortization of regulatory costs related to recoverable 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 decrease in Regulated T&D Electric Revenue)

Other Taxes

Other Taxes increased by $3 million to $19 million in 2013 from $16 million in 2012. The increase was primarily due to higher property taxes.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $5 million to a net expense of $21 million in 2013 from a net expense of $16 million in 2012. The increase was primarily due to an increase of $3 million in long-term debt interest expense due to $250 million of First Mortgage Bonds issued in June 2012 and $2 million associated with lower income related to AFUDC that is applied to capital projects.

<u>Income Tax Expense</u>

DPL’s income tax expense increased by $2 million to $25 million in 2013 from $23 million in 2012. DPL’s effective tax rates for the six months ended June 30, 2013 and 2012 were 39.7% and 40.4%, respectively. The decrease in the effective tax rate primarily resulted from 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 has determined that it can 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 a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $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 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, 2013 were $164 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 2012 Form 10-K, DPL presented the projected capital expenditures for the five-year period 2013 through 2017. There have been no changes in DPL's projected capital expenditures from those presented in the 2012 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 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 has 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.

Smart Grid

ACE is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, provide timely and accurate customer information and address government energy reduction goals. The installation of smart meters currently has been deferred by the NJBPU. 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."

Mitigation of Regulatory Lag

An important factor in the ability of ACE to earn its authorized rate of return is the willingness of the NJBPU to adequately recognize forward-looking costs in its rate structure in order to address the shortfall in revenues due to regulatory lag. ACE is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth. The NJBPU has approved certain cost recovery mechanisms in connection with ACE's Infrastructure Investment Program, which ACE had proposed in 2011 to extend and expand; however, in connection with the settlement in October 2012 of its electric distribution base rate case, ACE withdrew this proposal without prejudice. There can be no assurance that any future attempts by ACE to mitigate regulatory lag will be approved, or that even if approved, any proposed cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, ACE plans to file rate cases at least annually in an effort to align more closely its revenue and cash flow levels with other operation and maintenance spending and capital investments. ACE filed an electric distribution base rate case on December 11, 2012. See Note (6), "Regulatory Matters – Rate Proceedings," to the consolidated financial statements of ACE for more information about this base rate case.

Transmission ROE Challenge

On February 27, 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, 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 claim to 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. On April 3, 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.

Results of Operations

The following results of operations discussion compares the six months ended June 30, 2013 to the six months ended June 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$190	$171	$ 19
Default Electricity Supply Revenue	350	347	3
Other Electric Revenue	8	8	—
Total Operating Revenue	$548	$526	$ 22

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 include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 79	$ 67	$ 12
Commercial and industrial	68	58	10
Transmission and other	43	46	(3)
Total Regulated T&D Electric Revenue	$190	$171	$ 19

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	1,915	1,860	55
Commercial and industrial	2,415	2,457	(42)
Transmission and other	23	22	1
Total Regulated T&D Electric Sales	4,353	4,339	14

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	478	481	(3)
Commercial and industrial	65	65	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	544	547	(3)

Regulated T&D Electric Revenue increased by $19 million primarily due to:

- An increase of $12 million due to distribution and customer charge rate increases, each effective November 2012.
- An increase of $8 million due to a rate increase in the New Jersey Societal Benefit Charge effective July 2012 (which is offset in Deferred Electric Service Costs).
- An increase of $3 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.

The aggregate amount of these increases was partially offset by a decrease of $3 million in transmission revenue primarily attributable to a peak-load decrease effective January 2013.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$198	$209	$ (11)
Commercial and industrial	97	99	(2)
Other	55	39	16
Total Default Electricity Supply Revenue	$350	$347	$ 3

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.

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	1,510	1,556	(46)
Commercial and industrial	494	610	(116)
Other	7	10	(3)
Total Default Electricity Supply Sales	2,011	2,176	(165)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	386	407	(21)
Commercial and industrial	44	48	(4)
Other	—	—	—
Total Default Electricity Supply Customers	430	455	(25)

Default Electricity Supply Revenue increased by $3 million primarily due to:

- An increase of $16 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 $9 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $7 million as a result of higher Default Electricity Supply rates, primarily due to a Nonutility Generation Charge rate increase that became effective in July 2012.

The aggregate amount of these increases was partially offset by:

- A decrease of $26 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $3 million due to lower non-weather related average commercial customer usage.

For the six months ended June 30, 2013 and 2012, the percentages of ACE's total distribution sales that are derived from customers receiving Default Electricity Supply are 46% and 50%, 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 decreased by $18 million to $311 million in 2013 from $329 million in 2012 primarily due to:

- A decrease of $22 million primarily due to customer migration to competitive suppliers.
- A decrease of $2 million due to lower average electricity costs under Default Electricity Supply contracts.

The aggregate amount of these decreases was partially offset by an increase of $6 million due to higher electricity sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.

Other Operation and Maintenance

Other Operation and Maintenance expense increased by $7 million to $119 million in 2013 from $112 million in 2012 primarily due to:

- An increase of $3 million associated with higher tree trimming costs.
- An increase of $2 million primarily due to incremental preparation and restoration costs associated with a winter storm in March 2013.

Depreciation and Amortization

Depreciation and Amortization expense increased by $8 million to $63 million in 2013 from $55 million in 2012 primarily due to:

- An increase of $3 million due to utility plant additions.
- An increase of $3 million in amortization of stranded costs primarily as the result of higher revenue due to rate increases effective October 2012 for the ACE Transition Bond Charge and Market Transition charge tax (partially offset in Default Electric Supply Revenue).
- An increase of $1 million in amortization of storm costs.

Other Taxes

Other Taxes decreased by $2 million to $6 million in 2013 from $8 million in 2012. The decrease was primarily due to decreased Transitional Energy Facility Assessment taxes due to a rate decrease effective January 2013 (partially 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 Fuel and Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of New Jersey Societal Benefit Programs 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 $32 million to an expense reduction of $3 million in 2013 as compared to an expense reduction of $35 million in 2012, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Programs revenue rates and lower electricity supply costs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $2 million to a net expense of $35 million in 2013 from a net expense of $33 million in 2012 primarily due to lower income related to AFUDC that is applied to capital projects.

Income Tax Expense

ACE's income tax expense decreased by $7 million to $1 million in 2013 from $8 million in 2012. ACE's consolidated effective tax rates for the six months ended June 30, 2013 and 2012 were 5.9% and 33.3%, 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. In the first quarter of 2012, ACE recorded an interest benefit as a result of the effective settlement with the IRS with respect to the methodology used historically to calculate deductible mixed service 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 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 has determined that it can 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 a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $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 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, 2013 were $141 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 2012 Form 10-K, ACE presented the projected capital expenditures for the five-year period 2013 through 2017. There have been no changes in ACE's projected capital expenditures from those presented in the 2012 Form 10-K except for a reduction of approximately $150 million to more closely align its spending in New Jersey to the revenue it will receive following the June 21, 2013 NJBPU approval of the stipulation of settlement on the ACE petition to increase electric base rates. 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 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, which is referred to as the smart grid.

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 expenses associated with direct load control and other programs. For the six months ended June 30, 2013, ACE received award payments of $1 million. Cumulative award payments received by ACE as of June 30, 2013 were $15 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 (14), "Derivative Instruments and Hedging Activities," and Note (19), "Discontinued Operations," of the consolidated financial statements of PHI included in its 2012 Form 10-K, Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" in PHI's 2012 Form 10-K, and Note (13), "Derivative Instruments and Hedging Activities," and Note (17), "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' 2012 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, 2013, 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, 2013, 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.

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 (12), "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 2012 Form 10-K. There have been no material changes to any Reporting Company's risk factors as disclosed in the 2012 Form 10-K, except as set forth below.

Facilities and related systems may not operate as planned or may require significant capital or operation and maintenance expenditures, which could decrease revenues or increase expenses.

Operation of the Pepco, DPL and ACE transmission and distribution facilities and related systems involves many risks, including: the breakdown or failure of equipment; accidents; labor disputes; theft of copper wire or pipe; scams; failure of computer systems, software or hardware; and performance below expected levels. Older facilities, systems and equipment, even if maintained in accordance with sound engineering practices, may require significant capital expenditures for additions or upgrades to provide reliable operations or to comply with changing environmental requirements. Thefts of copper wire or pipe, which seek to capitalize on the current high market price of copper, increase the likelihood of poor system voltage control, electricity and streetlight outages, damage to equipment and property, and injury or death, as well as increasing the likelihood of damage to fuel lines, which can create an unsafe and potentially explosive condition. Natural disasters and weather, including tornadoes, hurricanes and snow and ice storms, also can disrupt transmission and distribution systems. Disruption of the operation of transmission or distribution facilities and related systems can reduce revenues and result in the incurrence of additional expenses that may not be recoverable from customers or through insurance. Upgrades and improvements to computer systems and networks may require substantial amounts of management's time and financial resources to complete, and may also result in system or network defects or operational errors due to the inexperience of using a new or upgraded system.

PHI is replacing customers' existing electric and gas meters with an AMI system. In addition to the replacement of existing meters, the AMI system involves the construction of a wireless network across the service territories of PHI's utility subsidiaries and the implementation and integration of new and existing information technology systems to collect and manage data made available by the advanced meters. The implementation of the AMI system involves a combination of technologies provided by multiple vendors. If the AMI system results in lower than projected performance, PHI's utility subsidiaries could experience higher than anticipated maintenance expenditures.

A recent court decision involving lease transactions could impact our ongoing litigation against the IRS involving certain cross-border energy lease investments, which may have a material negative impact on our results of operations and financial condition. (PHI only).

Prior to July 2013, PCI maintained a portfolio of cross-border energy lease investments involving public utility assets located outside of the United States, which as of December 31, 2012, had a net investment value of approximately $1.2 billion. PHI's cross-border energy lease investments, each of which was with a tax-indifferent party, have been under examination by the IRS as part of normal PHI federal income tax audits. In connection with the audits of PHI's federal income tax returns from 2001 to 2008, the IRS disallowed the depreciation and interest deductions in excess of rental income claimed by PHI with respect to its cross-border energy lease investments. In addition, the IRS has sought to recharacterize the leases as loan transactions. PHI commenced litigation in the U.S. Court of Federal Claims in January 2012 regarding the disallowance of certain tax benefits claimed by PHI on its federal tax returns for 2001 and 2002.

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 a lease-in, lease-out transaction. Under applicable accounting standards, the financial statement recognition of the tax benefits of PHI's uncertain tax position associated with the cross-border energy lease investments is permitted only if it is more likely than not that the position will be sustained. Further, the carrying value of the cross-border energy lease investments must be recalculated if there is a change or a projected change in the timing of the estimated tax benefits generated from these investments.

After analyzing the *Consolidated Edison* ruling, PHI has determined that its tax position with respect to the tax benefits associated with the cross-border energy leases no longer meets the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded a non-cash charge of $377 million (after-tax) in the first quarter of 2013, 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 its estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed.

After consideration of certain tax benefits arising from matters unrelated to these lease investments, PHI estimated that, as of March 31, 2013, it would have been obligated to pay approximately $192 million in additional federal and state taxes and approximately $50 million of interest on the additional federal and state taxes. 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. While PHI presently believes that it is more likely than not that no penalty will be incurred, the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due. PHI continues to weigh its options with respect to its litigation with the IRS.

In March 2013, PHI began to pursue the early termination of its remaining cross-border energy lease investments with the respective lessees. The early termination of the remaining cross-border energy lease investments was completed in July 2013. The aggregate financial impact of the completion of the early terminations of the cross-border energy lease investments in July 2013 is expected to be a pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax) for the year ending December 31, 2013.

PHI's subsidiaries are subject to collective bargaining agreements that could impact their business and operations.

As of December 31, 2012, 54% of employees of PHI and its subsidiaries, collectively, were represented by various labor unions. PHI's subsidiaries are parties to five collective bargaining agreements with four local unions that represent these employees. Collective bargaining agreements are generally renegotiated every three to five years, and the risk exists that there could be a work stoppage after expiration of an agreement until a new collective bargaining agreement has been reached. Labor negotiations typically involve bargaining over wages, benefits and working conditions, including management rights. PHI's last work stoppage, a two-week strike by DPL's employees, occurred in 2010. During that strike, DPL used management and contractor employees to maintain essential operations.

One of the collective bargaining agreements to which PHI's subsidiaries are a party was set to expire on June 25, 2013. After a short contract extension, the parties reached a new four-year agreement that was ratified by union members on July 11, 2013. Though PHI believes that protracted work stoppages are unlikely, such an event could result in a disruption of the operations of the affected utility, which could, in turn, have a material adverse effect upon the business, results of operations, cash flow and financial condition of the affected utility and PHI.

The agreements that govern PHI's primary credit facility and various term loan agreements that have been entered into from time to time contain a consolidated indebtedness covenant that may limit discretion of each borrower to incur indebtedness or reduce its equity.

Under the terms of PHI's primary credit facility, of which each Reporting Company is a borrower, and of various term loan agreements that have been entered into from time to time, the consolidated indebtedness of a borrower cannot exceed 65% of its consolidated capitalization. If a borrower's equity were to decline or its debt were to increase to a level that caused its debt to exceed this limit, lenders under the credit facility would be entitled to refuse any further extension of credit and to declare all of the outstanding debt under the credit facility or the term loan immediately due and payable. To avoid such a default, a waiver or renegotiation of this covenant would be required, which would likely increase funding costs and could result in additional covenants that would restrict each Reporting Company's operational and financing flexibility.

Each borrower's ability to comply with this covenant is subject to various risks and uncertainties, including events beyond the borrower's control. For example, events that could cause a reduction in PHI's equity include, without limitation, potential IRS taxes, interest and penalties associated with PHI's cross-border energy lease investments or a significant write-down of PHI's goodwill. Even if each borrower is able to comply with this covenant, the restrictions on its ability to operate its business in its sole discretion could harm its and PHI's business by, among other things, limiting the borrower's ability to incur indebtedness or reduce equity in connection with financings or other corporate opportunities that it may believe would be in its best interests or the interests of PHI's stockholders to complete.

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.

Item 3. DEFAULTS UPON SENIOR SECURITIES

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.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

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
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	Bylaws	Exhibit 3.6 to PHI's Form 10-K, March 1, 2013.
3.7	Pepco	By-Laws	Exhibit 3.2 to Pepco's Form 10-Q, May 5, 2006.
3.8	DPL	Amended and Restated Bylaws	Exhibit 3.2.1 to DPL's Form 10-Q, May 9, 2005.
3.9	ACE	Amended and Restated Bylaws	Exhibit 3.2.2 to ACE's Form 10-Q, May 9, 2005.
4.1	DPL	One Hundred and Eleventh Supplemental Indenture	Filed herewith.
4.2	ACE	Form of Term Loan Note (included in Exhibit 10.1 hereto)	—
10.1	ACE	$100,000,000 Term Loan Agreement, dated May 10, 2013, by and among ACE, KeyBank National Association, as Administrative Agent, SunTrust Bank, as Documentation Agent, and the lenders party thereto	Exhibit 10 to ACE's Form 8-K, May 10, 2013.
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.
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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.
32.3	DPL	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
32.4	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)

August 6, 2013

By /s/ FREDERICK J. 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

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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 4.1

This Instrument Prepared By:
/s/ Charlene Anderson
Charlene Anderson
Delmarva Power & Light Company
Mailstop 92DC42
500 N. Wakefield Drive,
Newark, DE 19702-5440

DELMARVA POWER & LIGHT COMPANY

TO

THE BANK OF NEW YORK MELLON,
Trustee.

ONE HUNDRED AND ELEVENTH SUPPLEMENTAL
INDENTURE

Dated as of January 1, 2013
(but executed on the dates shown on the execution page)

This **ONE HUNDRED AND ELEVENTH SUPPLEMENTAL INDENTURE,** dated as of the first day of January, 2013 (but executed on the dates hereinafter shown), made and entered into by and between DELMARVA POWER & LIGHT COMPANY, a corporation of the State of Delaware and the Commonwealth of Virginia, hereinafter called the Company and THE BANK OF NEW YORK MELLON, a New York banking corporation, hereinafter called the Trustee;

WITNESSETH:

WHEREAS, the Company heretofore executed and delivered its Indenture of Mortgage and Deed of Trust (hereinafter in this One Hundred and Eleventh Supplemental Indenture called the "Original Indenture"), dated as of October 1, 1943, to The New York Trust Company, a corporation of the State of New York, as Trustee, to which The Bank of New York Mellon is successor Trustee, to secure the First Mortgage Bonds of the Company, unlimited in aggregate principal amount and issuable in series, from time to time, in the manner and subject to the conditions set forth in the Original Indenture granted and conveyed unto the Trustee, upon the trusts, uses and purposes specifically therein set forth, certain real estate, franchises and other property therein described, including property acquired after the date thereof, except as therein otherwise provided; and

WHEREAS, the Original Indenture has been supplemented by one hundred and ten supplemental indentures specifically subjecting to the lien of the Original Indenture as though included in the granting clause thereof certain property in said supplemental indentures specifically described and amending and modifying the provisions of the Original Indenture (the Original Indenture, as amended, modified and supplemented by all of the indentures supplemental thereto, including this One Hundred and Eleventh Supplemental Indenture, is hereinafter in this One Hundred and Eleventh Supplemental Indenture called the "Indenture"); and

WHEREAS, the execution and delivery of this One Hundred and Eleventh Supplemental Indenture has been duly authorized by Unanimous Written Consent of the Board of Directors of the Company, and all conditions and requirements necessary to make this One Hundred and Eleventh Supplemental Indenture a valid, binding and legal instrument in accordance with its terms, for the purposes herein expressed, and the execution and delivery hereof, have been in all respects duly authorized; and

WHEREAS, it is provided in and by the Original Indenture, inter alia, as follows:

> "IT IS HEREBY AGREED by the Company that all the property, rights and franchises acquired by the Company after the date hereof (except any hereinbefore or hereinafter expressly excepted) shall (subject to the provisions of Section 9.01 hereof and to the extent permitted by law) be as fully embraced within the lien hereof as if such property, rights and franchises were now owned by the Company and/or specifically described herein and conveyed hereby;"

and

WHEREAS, the Company has acquired certain other property, real, personal and mixed, which heretofore has not been specifically conveyed to the Trustee;

NOW, THEREFORE, this ONE HUNDRED AND ELEVENTH SUPPLEMENTAL INDENTURE WITNESSETH that for and in consideration of the premises and in pursuance of the provisions of the Indenture:

The Company has granted, bargained, sold, released, conveyed, assigned, transferred, mortgaged, pledged, set over and confirmed, and by these presents does grant, bargain, sell, release, convey, assign, transfer, mortgage, pledge, set over and confirm unto the Trustee and to its successors in the trust in the Indenture created, to its and their assigns forever, all the following described properties of the Company, and does confirm that the Company will not cause or consent to a partition, either voluntary or through legal proceedings, of property, whether herein described or heretofore or hereafter acquired, in which its ownership shall be as tenant in common, except as permitted by, and in conformity with, the provisions of the Indenture and particularly of Article IX thereof:

State and County
MARYLAND
Wicomico County

Property Name	Received For Record	Deed Records Book	Deed Records Page	Tax Map No.
Hudson Substation	05/04/12	3433	323	3146 3147 3149

Together with all other property, real, personal and mixed, tangible and intangible (except such property as in said Indenture expressly excepted from the lien and operation thereof), acquired by the Company on or prior to December 31, 2012, and not heretofore specifically subjected to the lien of the Indenture.

Also without limitation of the generality of the foregoing, the easements and rights-of-way and other rights in or not used in connection with the Company's operations, which are conveyed to the Company and recorded in the following Real Property Deed Records to which reference is made for a more particular description, to wit:

State and County
DELAWARE
New Castle

Received For Record	Instrument No.	Tax ID No
05/30/2008	20080820-0057207	07-032.20-003, 048, 049, 051, 052, 053, 054, 055, 057, 072
10/06/2011	20120306-0012424	13-014.30-227 thru 392 13-019.10-142 thru 193
10/26/2011	20120606-0031404	26-049.10-019 thru 025
12/21/2011	20120606-0031403	26-006-20-001
01/05/2012	20120105-0000802	13-021.00-010
01/05/2012	20120105-0000803	11-026.00-011
01/05/2012	20120105-0000804	20-002.00-059
01/05/2012	20120105-0000805	11-023.20-330 & 11-023.20-331
01/05/2012	20120105-0000806	14-012020-080, 14-012.20-083, 14-012.20-086 & 087, 14-012.20-082, 14-012.20-038 thru 061, 14-012.20-83 thru 082, 14-012.20-085, 14-012.20-086, 14-012.20-090 thru 123
01/05/2012	20120105-0000807	11-009.00-033
01/05/2012	20120105-0000808	08-043.40-330
01/05/2012	20120105-0000809	14-003.00-006
01/18/2012	20120606-0031402	23-018.00-002
02/17/2012	20120606-0031405	26-027.10-159

02/29/2012	20121003-0057047	080440133
03/12/2012	20120606-0031401	0603100167
04/03/2012	20120606-0031406	06-052.00-075
05/11/2012	20120529-0029251	06-032.00-306
05/14/2012	20121003-0057048	08-050.40-008
06/15/2012	20121031-0062830	09-017.00-030
06/22/2012	20120625-0035200	11-003.30-027
11/23/2012	20121003-0057049	11-018.10-001 thru 11-018.10-008 & 11-014.30-136 thru 11-014.30-144

State and County
DELAWARE
Kent

Received For Record	Instrument No.	Tax ID No
01/06/2012	2012-201837	4-00-04700-01-4403-00001
01/06/2012	2012-201837	4-00-04700-01-4403-00001
03/16/2012	2012-211276	8-00-13900-01-1400-00001
03/19/2012	2012-211275	2-00-08500-02-0502-00001 2-00-08500-02-0503-00001
04/03/2012	2012-211274	7-02-09408-02-1100-00001
04/03/2012	2012-211273	7-02-09408-02-0300-00001

State and County
DELAWARE
Sussex

Received For Record	Deed Records		Tax ID No
	Book	Page	
01/06/2012	3960	49	3-34 19.00 380.02
01/06/2012	3960	57	1-32 6.00 95.00
01/06/2012	3960	51	3-34 13.20 288.00 290.00
01/06/2012	3960	53	3-34 13.20 291.00 292.00 295.00
01/06/2012	3960	55	3-34 13.20 289.00 293.00 294.00
01/06/2012	3960	59	5-30 10.00 1.00
01/06/2012	3960	61	1-34 11.00 25.02
01/06/2012	3960	64	3-34 14.13 365.00
01/06/2012	3960	66	1-34 13.19 127.01
03/20/2012	4007	236	2-30-26.00-75.00
03/26/2012	4007	243	1-34-9.00-13.00
04/01/2012	4007	240	1-34-11.00-189.00
04/11/2012	4007	238	3-34-13.20-85.00, 85.01, 86.00, 92.00, 93.00, 94.00
05/05/2012	4007	234	1-34-8.00-45.00

State and County
MARYLAND
Cecil

Received For Record	Deed Records Book	Page	Tax Id #
08/30/2011	3160	062	0023/0490 LT 1,3,4,5
11/23/2011	3208	267	0025/0791
12/21/2011	3160	060	0024/0189 ALL LOTS
01/03/2012	3160	066	0036/220
01/10/2012	3131	474	Map 0309 Par 0391
01/10/2012	3131	477	Map 13 Par 736
01/10/2012	3131	479	Map 36 Par 0220 Lt 2
01/10/2012	3131	481	Map 0048 Par 0112
01/10/2012	3131	484	Map 48 Par 6
01/10/2012	3131	487	Map 0031 Par 1265 All lots inclusive
01/10/2012	3131	489	Map 0031 Par 1265 All lots inclusive
01/10/2012	3131	491	Map 43 Par 245
02/22/2012	3208	259	0016/0552
02/22/2012	3208	257	0016/0552
03/09/2012	3208	263	0023/0078
03/15/2012	3208	265	0037/0008 ALL LOTS
04/02/2012	3208	255	0035/0456
04/04/2012	3208	261	10/810
04/30/2012	3208	253	0461/0500
05/10/2012	3208	251	016/0484
05/10/2012	3208	249	016/0484
05/10/2012	3208	247	016/0484
06/05/2012	3271	008	17/0508
06/11/2012	3270	496	29/577
06/13/2012	3271	005	3/6
07/20/2012	3271	001	10/0479
07/20/2012	3271	003	10/0081
08/15/2012	3270	493	0485/0025
08/18/2012	3160	064	0036/0220 LT 3

State and County
MARYLAND
Dorchester

Received For Record	Deed Records Book	Page	Tax Id #
01/06/2012	1065	279	Map 0200 Par 0053
02/22/2012	1090	033	21/89
05/17/12	55	150	308/11/5721
09/19/12	1108	463	1108/463

State and County
MARYLAND
Harford

Received For Record	Deed Records Book	Page	Tax Id#
08/29/2011	09721	020	0027/0466
11/18/2011	09721	024	HARFORD 5-A10/0288
11/17/2011	09504	233	17/242 LT 4
06/26/2012	09918	028	10/0249

State and County
MARYLAND
Kent

Received For Record	Deed Records Book	Page	Tax Id #
01/05/2012	0704	493	Map 58 Par 6
01/05/2012	0704	495	Map 0012 Par 0107
01/20/2012	0720	084	37/5585
01/19/2012	0720	082	0037/0299
01/19/2012	0720	078	0051/0157
01/20/2012	0710	003	30/55 LT4
01/24/2012	0710	007	00516/00001
01/24/2012	0710	009	0055/0124 LT3
01/27/2012	0710	005	055/0124 LT1
02/03/2012	0710	011	0046/0142
02/15/2012	0720	080	0045/0012
02/15/2012	0720	074	0046/0173
02/15/2012	0710	001	30/24
02/28/2012	0720	076	0046/0034
04/02/2012	0720	072	51/493
04/12/2012	0720	068	0051/0174

04/17/2012	0720	070	0055/0100A
04/23/2012	0720	066	0013/0071
05/16/2012	0720	064	0055/0102
06/1/11	0732	005	0732/005
06/12/12	0732	007	0732/007
06/19/12	0732	001	30/24/2
06/21/12	0732	003	55/2
10/10/2012	0732	201	Map 0042, Par 0158 – 20.0789 acres Tax Map 42 Parcels, 25, 30 & 49

State and County
MARYLAND
Queen Anne's

Received For Record	Deed Records Book	Page	Tax Id #
11/07/2011	2109	343	058A/0290 (LOTS1,2,3,4)
11/07/2011	2109	341	058A/0401 (LOTS1,2,3)
01/06/2012	2109	345	0029/0064
02/06/2012	2086	005	21/2
02/14/2012	2109	337	51/34 LT 1
03/02/2012	2109	339	0060/0003 LT11
03/08/2012	2109	335	0031/0019
03/09/2012	2109	328	59/115
03/20/2012	2109	330	0009/0064
03/20/2012	2109	321	0009/0064
03/28/2012	2109	319	0009/0064
03/28/2012	2109	323	0009/0092
04/04/2012	2109	325	51/27
04/05/2012	2109	326	35/186
04/25/2012	2109	317	28/3
04/25/2012	2109	315	28/41
04/25/2012	2109	313	28/2
05/30/2012	2137	596	28/120
05/30/2012	2137	598	28/103
06/06/2012	2137	584	58D/816
06/06/2012	2137	586	58D/65
06/06/2012	2137	586	58D/207
06/06/2012	2137	586	58D/21
06/06/2012	2137	586	58D/22
06/06/2012	2137	586	58D/13
06/07/2012	2137	580	21/12
06/07/2012	2137	580	21/12
08/27/2012	2130	466	65/1
12/31/2012	2158	509	44 10 98

State and County
MARYLAND
Somerset

Received For Record	Deed Records Book	Page	Tax Id #
08/06/2007	0826	484	440868-1 AND 440856-8/ 316
01/06/2012	0817	290	Map 0009 Par 27
01/06/2012	0817	292	Map 0057 Par 0097
01/06/2012	0817	294	Map 0064 Par 0753
03/27/2012	0826	486	0015/0028
04/27/2012	0826	482	0200/0294A
04/27/2012	0826	480	0039/0209
07/03/2012	0833	581	22/184
08/23/2012	0833	579	15/333

State and County
MARYLAND
Talbot

Received For Record	Deed Records Book	Page	Tax Id#
12/15/2011	1990	370	38/45
01/05/2012	1950	058	Map 6 Par 7
01/05/2012	1950	060	Map 59 Par 86
08/21/2012	2024	206	55/27/1
08/21/2012	2024	208	55/26

State and County
MARYLAND
Wicomico

Received For Record	Deed Records Book	Page	Tax Id #
07/21/2011	3410	007	29/490
09/09/2011	3355	020	106/1655 LT 1
10/21/2011	3410	012	58/0062
12/02/2011	3410	009	49/173
01/04/2012	3410	014	803/599
01/05/2012	3390	60	Map 0058 Par 0063
01/05/2012	3390	62	Map 0057 Par 0241
01/05/2012	3390	64	Map 802 Par 2177
01/05/2012	3390	67	Map 802 Par 1005

01/05/2012	3390	72	Map 50 Par 176 Lt 4A
01/05/2012	3390	74	Map 400 par 328
01/05/2012	3390	77	Map 29 Par 490
01/05/2012	3390	79	Map 51 Par 0059
01/05/2012	3390	81	Map 29 Par 528 Lt 5
01/05/2012	3390	83	Map 29 Par 528 Lt 4
01/09/2012	3410	019	0059/0023
01/11/2012	3449	177	600/583
02/01/2012	3410	017	0047/0499
02/28/2012	3449	174	63/218
03/26/2012	3449	158	0019/0054
03/26/2012	3449	156	0019/0055
04/03/2012	3449	163	0037/0293
04/03/2012	3434	219	48/214 (LT2A& 2C), 48/213
04/17/2012	3449	160	115/657
05/11/2012	3449	168	29/12
05/15/2012	3449	165	108/1100
05/16/2012	3449	171	39/406 Block B Lot 3 and 4, Block C 2-4
10/27/2010	3491	316	3491/316
11/02/2010	3491	314	3491/314
11/05/2012	3491	318	38/433/62

State and County
MARYLAND
Worcester

Received For Record	Deed Records		Tax Id #
	Book	Page	
11/03/2005	5844	305	8/3
01/05/2012	5811	192	Map 26 Par 302
01/05/2012	5811	195	Map 26 Par 301
01/05/2012	5811	198	Map 0010 Par 0068
01/05/2012	5811	203	Map 10 Par 28 & 37
03/06/2012	5911	253	113/7022
03/23/2012	5911	251	27/704
05/17/2012	5911	248	201/159
05/15/2012	5911	245	56/49
07/09/2012	5990	317	55/11
07/20/2012	5990	315	10/0089

The following is a schedule of bonds issued under the Eighty-Eighth Supplemental Indenture and Credit Line Deed of Trust, effective as of October 1, 1994, that can be designated as First Mortgage Bonds, Series I, which may also be designated as Secured Medium Term Notes, Series I; and First Mortgage Bonds, Pledged Series I.

First Mortgage Bonds, Series I/Secured Medium Term Notes, Series I

Issuance Date	Tranche	Maturity	Principal
06/19/95	7.71% Bonds	06/01/25	$100,000,000
06/19/95	6.95% Amortizing Bonds	06/01/08	$ 25,800,000
11/25/08	6.40% Bonds	12/01/13	$250,000,000

First Mortgage Bonds, Pledged Series I

Issuance Date	Tranche	Maturity	Principal
10/12/94	1994	10/01/29	$ 33,750,000
Total Bonds Issued:			$409,550,000

As supplemented and amended by this One Hundred and Eleventh Supplemental Indenture, the Original Indenture and all indentures supplemental thereto are in all respects ratified and confirmed and the Original Indenture and the aforesaid supplemental indentures and this One Hundred and Eleventh Supplemental Indenture shall be read, taken and construed as one and the same instrument.

This One Hundred and Eleventh Supplemental Indenture shall be simultaneously executed in several counterparts, and all such counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

The recitals of fact contained herein shall be taken as the statements of the Company, and the Trustee assumes no responsibility for the correctness of the same.

The debtor and its mailing address are Delmarva Power & Light Company, Mailstop 92DC42, 500 N. Wakefield Drive, Newark, Delaware 19702-5440. The secured party and its address, from which information concerning the security interest hereunder may be obtained, is The Bank of New York Mellon, 525 William Penn Place, 38th Floor, Pittsburgh, Pennsylvania 15259, Attn: Ms. Leslie Lockhart, Corporate Trust Officer.

The Company acknowledges that it received a true and correct copy of this One Hundred and Eleventh Supplemental Indenture.

This One Hundred and Eleventh Supplemental Indenture is executed and delivered pursuant to the provisions of Section 5.11 and paragraph (a) of Section 17.01 of the Indenture for the purpose of conveying, transferring and assigning to the Trustee and of subjecting to the lien of the Indenture with the same force and effect as though included in the granting clause thereof the above described property so acquired by the Company on or prior to the date of execution, and not heretofore specifically subject to the lien of the Indenture; but nothing contained in this One Hundred and Eleventh Supplemental Indenture shall be deemed in any manner to affect (except for such purposes) or to impair the provisions, terms and conditions of the Original Indenture, or of any indenture supplemental thereto and the provisions, terms and conditions thereof are hereby expressly confirmed.

(SIGNATURE PAGE FOLLOWS)

IN WITNESS WHEREOF, the Company has caused this instrument to be signed in its name and behalf by its President, and its corporate seal to be hereunto affixed and attested by its Assistant Secretary and the Trustee has caused this instrument to be signed in its name and behalf by a Vice President and its corporate seal to be hereunto affixed and attested by an authorized officer, effective as of the 1st day of January, 2013.

DELMARVA POWER & LIGHT COMPANY

Date of Execution

By /s/ David M. Velazquez
DAVID M. VELAZQUEZ, PRESIDENT

April 12, 2013

[Seal]

Attest:
/s/ Charlene Anderson
CHARLENE ANDERSON, ASSISTANT SECRETARY

DISTRICT OF COLUMBIA: SS.

BE IT REMEMBERED that on this12th day of April, 2013, personally came before me, a notary public for the District of Columbia, David M. Velazquez, President of DELMARVA POWER & LIGHT COMPANY, a corporation of the State of Delaware and the Commonwealth of Virginia (the “Company”), party to the foregoing instrument, known to me personally to be such, and acknowledged the instrument to be his own act and deed and the act and deed of the Company; that his signature is in his own proper handwriting; that the seal affixed is the common or corporate seal of the Company; and that his act of signing, sealing, executing and delivering such instrument was duly authorized by resolution of the Board of Directors of the Company.

GIVEN under my hand and official seal the day and year aforesaid.

/s/ Linda J. Epperly
Notary Public, District of Columbia
My commission expires January 1, 2015.

THE BANK OF NEW YORK MELLON,
as Trustee

[Seal]

Date of Execution

By /s/ Laurence J. O'Brien
LAURENCE J. O'BRIEN, VICE PRESIDENT

April 12, 2013

Attest:

/s/ Latoya S. Elvin
LATOYA S. ELVIN, VICE PRESIDENT

STATE OF NEW YORK)
) SS.
COUNTY OF NEW YORK)

BE IT REMEMBERED that on this 12th day of April, 2013, personally came before me, a Notary Public for the State of New York, Laurence J. O'Brien, Vice President of THE BANK OF NEW YORK MELLON, a New York banking corporation (the "Trustee"), party to the foregoing instrument, known to me personally to be such, and acknowledged the instrument to be his own act and deed and the act and deed of the Trustee; that his signature is his own proper handwriting; that the seal affixed is the common or corporate seal of the Trustee; and that his act of signing, sealing, executing and delivering said instrument was duly authorized by resolution of the Board of Directors of the Trustee.

GIVEN under my hand and official seal the day and year aforesaid.

/s/ Danny Lee
Notary Public, State of New York
My commission expires February 20, 2015.

CERTIFICATE OF RESIDENCE

THE BANK OF NEW YORK MELLON, successor Trustee to the Trustee within named, hereby certifies that it has a residence at 101 Barclay Street, in the Borough of Manhattan, in The City of New York, in the State of New York.

THE BANK OF NEW YORK MELLON

By /s/ Laurence J. O'Brien
Name: Laurence J. O'Brien
Title: Vice President

Certification

This document was prepared under the supervision of an attorney admitted to practice before the Court of Appeals of Maryland, or by or on behalf of one of the parties named in the within instrument.

/s/ Charlene Anderson
Charlene Anderson

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: August 6, 2013

/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: August 6, 2013

/s/ FREDERICK J. 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: August 6, 2013

/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: August 6, 2013

/s/ FREDERICK J. 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: August 6, 2013

/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: August 6, 2013

/s/ FREDERICK J. 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: August 6, 2013

/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: August 6, 2013

/s/ FREDERICK J. 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, 2013, 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.

August 6, 2013	/s/ JOSEPH M. RIGBY Joseph M. Rigby Chairman of the Board, President and Chief Executive Officer
August 6, 2013	/s/ FREDERICK J. 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, 2013, 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.

August 6, 2013	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
August 6, 2013	/s/ FREDERICK J. 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, 2013, 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.

August 6, 2013	/s/ DAVID M. VELAZQUEZ
	David M. Velazquez President and Chief Executive Officer
August 6, 2013	/s/ FREDERICK J. 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, 2013, 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.

August 6, 2013	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
August 6, 2013	/s/ FREDERICK J. 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, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
		(millions of dollars)				
(Loss) Earnings						
Net (loss) income from continuing operations	$ (392)	$ 259	$ 258	$ 119	$ 195	$ 156
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	(1)	(1)	3	1	(2)	4
Minority interest loss	—	—	—	—	—	—
Income tax expense (benefit) related to continuing operations	167	138	148	(2)	86	77
Pre-tax (loss) income for common stock	(226)	396	409	118	279	237
Add: Fixed charges*	151	295	286	323	344	333
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	(1)
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
(Loss) Earnings	$ (75)	$ 691	$ 695	$ 441	$ 623	$ 569
***Fixed Charges**						
Interest on long-term debt	$ 133	$ 258	$ 250	$ 280	$ 298	$ 292
Interest capitalized	—	—	—	—	—	1
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	7	16	14	21	23	16
Interest component of rentals	11	21	22	22	23	24
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 151	$ 295	$ 286	$ 323	$ 344	$ 333
Ratio of (loss) earnings to fixed charges	(0.50)	2.34	2.43	1.37	1.81	1.71
Deficiency	$ 226	$ —	$ —	$ —	$ —	$ —

(a) Pepco Holdings, Inc. 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 99.2

POTOMAC ELECTRIC POWER COMPANY

	Six Months Ended June 30, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
		(millions of dollars)				
Earnings						
Net income for common stock	$ 60	$ 126	$ 99	$ 108	$ 106	$ 116
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	22	48	36	37	76	64
Pre-tax income for common stock	82	174	135	145	182	180
Add: Fixed charges*	60	113	111	111	114	106
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 142	$ 287	$ 246	$ 256	$ 296	$ 286
***Fixed Charges**						
Interest on long-term debt	$ 54	$ 101	$ 97	$ 97	$ 99	$ 90
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	3	5	4	4	4	5
Interest component of rentals	3	7	10	10	11	11
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 60	$ 113	$ 111	$ 111	$ 114	$ 106
Ratio of earnings to fixed charges (a)	2.37	2.54	2.22	2.31	2.60	2.70

(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, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
			(millions of dollars)			
Earnings						
Net income for common stock	$ 38	$ 73	$ 71	$ 45	$ 52	$ 68
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	25	44	42	31	16	45
Pre-tax income for common stock	63	117	113	76	68	113
Add: Fixed charges*	28	52	49	48	47	43
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 91	$ 169	$ 162	$ 124	$ 115	$ 156
***Fixed Charges**						
Interest on long-term debt	$ 24	$ 45	$ 42	$ 43	$ 42	$ 38
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	4	4	3	3	3
Interest component of rentals	2	3	3	2	2	2
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 28	$ 52	$ 49	$ 48	$ 47	$ 43
Ratio of earnings to fixed charges (a)	3.25	3.25	3.31	2.58	2.45	3.63

(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, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
			(millions of dollars)			
Earnings						
Net income for common stock	$ 16	$ 35	$ 39	$ 53	$ 41	$ 64
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	1	18	33	43	17	30
Pre-tax income for common stock	17	53	72	96	58	94
Add: Fixed charges*	37	75	74	69	72	67
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 54	$ 128	$ 146	$ 165	$ 130	$ 161
***Fixed Charges**						
Interest on long-term debt	$ 34	$ 69	$ 69	$ 63	$ 67	$ 60
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	1	2	2	3	2	4
Interest component of rentals	2	4	3	3	3	3
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 37	$ 75	$ 74	$ 69	$ 72	$ 67
Ratio of earnings to fixed charges (a)	1.46	1.71	1.97	2.39	1.81	2.40

(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.