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 September 30, 2012

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 October 25, 2012
Pepco Holdings	229,471,971 ($.01 par value)
Pepco	100 ($.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.

TABLE OF CONTENTS

GLOSSARY OF TERMS

Term	Definition
2011 Form 10-K	The Annual Report on Form 10-K for the year ended December 31, 2011, as amended, for each Reporting Company, as applicable
ACE	Atlantic City Electric Company
ACE Funding	Atlantic City Electric Transition Funding LLC
AMI	Advanced metering infrastructure
AOCL	Accumulated Other Comprehensive Loss
ASC	Accounting Standards Codification
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
Conectiv Energy	Subsidiaries of Conectiv Energy Holding Company, a disposition plan for which was approved by PHI's Board of Directors in April 2010 and has been completed
CRMC	PHI's Corporate Risk Management Committee
CSA	Credit Support Annex
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
Derecho	A rapidly moving thunderstorm with hurricane-force winds
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
EPA	U.S. Environmental Protection Agency
EPS	Earnings per share
Excess Depreciation Rider	A credit rider in New Jersey expected to expire August 31, 2013, which is designed to refund to customers certain excess depreciation reserve funds as previously directed by the NJBPU
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
GWh	Gigawatt hour
IIP	ACE's Infrastructure Investment Program
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association Master Agreement
ISRA	New Jersey's Industrial Site Recovery Act
LIBOR	London Interbank Offered Rate

Term	Definition
MAPP	Mid-Atlantic Power Pathway
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
MMBtu	One Million British Thermal Units
MPSC	Maryland Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability
New Jersey Settlement	A stipulation of settlement signed by the parties to ACE's electric distribution base rate case, which was approved by the NJBPU on October 23, 2012
NJBPU	New Jersey Board of Public Utilities
NPCC	Northeast Power Coordinating Council
NUGs	Non-utility generators
NYMEX	New York Mercantile Exchange
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
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
RFC	Reliability*First* Corporation
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
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
SPCC	Spill Prevention, Control, and Countermeasure plans, required pursuant to federal regulations requiring plans for facilities using oil-containing equipment in proximity to surface waters
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
VADEQ	Virginia Department of Environmental Quality
VaR	Value at Risk

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 and by 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 the possible disallowance of recovery of costs and expenses;
- 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 vulnerable to increased regulatory oversight and negative customer perception;
- 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 electricity and natural gas 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 (NERC) and other applicable electric reliability organizations;
- Legal and administrative proceedings (whether civil or criminal) and settlements that affect a Reporting Company's or its subsidiaries' business and profitability;
- Pace of entry into new markets;
- Interest rate fluctuations and the impact of credit and capital market conditions on the ability to obtain funding on favorable terms; and
- Effects of geopolitical 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 included in Part I, Item 1A. Risk Factors and other statements in each Reporting Company's annual report on Form 10-K for the year ended December 31, 2011, as amended to include the executive compensation and other information required by Part III of Form 10-K (which information originally had been omitted as permitted by that form) (the 2011 Form 10-K), as filed with the Securities and Exchange Commission (SEC), in each Reporting Company's quarterly report on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012, as filed with the 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 Form 10-Q.

Any forward-looking statements speak only as to the date this Quarterly Report on Form 10-Q 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, nor can the impact of any such factor be assessed 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.

* * *

INVESTOR INFORMATION

PHI routinely makes available important information with respect to each Reporting Company, including copies of each Reporting Company's annual, periodic and current reports filed or furnished with the Securities and Exchange Commission under the Securities Exchange Act of 1934, free of charge on PHI's website at http://www.pepcoholdings.com/investors. PHI recognizes its website as a key channel of distribution to reach public investors and as a means of disclosing material non-public information to comply with each Reporting Company's disclosure obligations under SEC Regulation FD. Information contained on PHI's website shall not be deemed incorporated into, or to be part of, this Quarterly Report, and any website references are not intended to be made through active hyperlinks.

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.

Item	Registrants: Pepco Holdings	Pepco*	DPL*	ACE
Consolidated Statements of Income	4	55	75	99
Consolidated Statements of Comprehensive Income	5	N/A	N/A	N/A
Consolidated Balance Sheets	6	56	76	100
Consolidated Statements of Cash Flows	8	58	78	102
Consolidated Statement of Equity	9	59	79	103
Notes to Consolidated Financial Statements	10	60	80	104

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars, except per share data)			
Operating Revenue				
Power Delivery	$ 1,335	$ 1,329	$ 3,374	$ 3,671
Pepco Energy Services	131	317	544	1,005
Other	10	2	29	22
Total Operating Revenue	1,476	1,648	3,947	4,698
Operating Expenses				
Fuel and purchased energy	709	948	1,948	2,759
Other services cost of sales	38	42	132	128
Other operation and maintenance	230	239	679	682
Depreciation and amortization	122	115	343	325
Other taxes	121	126	330	346
Gain on early termination of finance leases held in trust	(39)	—	(39)	(39)
Deferred electric service costs	29	(17)	(6)	(49)
Impairment losses	2	—	5	—
Total Operating Expenses	1,212	1,453	3,392	4,152
Operating Income	264	195	555	546
Other Income (Expenses)				
Interest expense	(68)	(64)	(198)	(189)
Loss from equity investments	—	(3)	—	(4)
Other income	9	7	27	27
Total Other Expenses	(59)	(60)	(171)	(166)
Income from Continuing Operations Before Income Tax Expense	205	135	384	380
Income Tax Expense Related to Continuing Operations	93	55	142	143
Net Income from Continuing Operations	112	80	242	237
Income from Discontinued Operations, net of Income Taxes	—	—	—	1
Net Income	$ 112	$ 80	$ 242	$ 238
Basic and Diluted Share Information				
Weighted average shares outstanding – Basic (millions)	229	226	228	226
Weighted average shares outstanding – Diluted (millions)	231	226	229	226
Earnings per share of common stock from Continuing Operations – Basic and Diluted	$ 0.49	$ 0.35	$ 1.06	$ 1.05
Earnings per share of common stock from Discontinued Operations – Basic and Diluted	—	—	—	—
Earnings per share – Basic and Diluted	$ 0.49	$ 0.35	$ 1.06	$ 1.05

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Net Income	$ 112	$ 80	$ 242	$ 238
Other Comprehensive Income (Loss) from Continuing Operations				
Gain (losses) on commodity derivatives designated as cash flow hedges:				
Gains arising during period	—	—	—	2
Amount of losses reclassified into income	6	16	31	62
Net gains on commodity derivatives	6	16	31	64
Losses on treasury rate locks reclassified into income	1	1	1	1
Pension and other postretirement benefit plans	1	(2)	(4)	(6)
Other comprehensive income, before income taxes	8	15	28	59
Income tax expense related to other comprehensive income	4	6	12	24
Other comprehensive income, net of income taxes	4	9	16	35
Comprehensive Income	$ 116	$ 89	$ 258	$ 273

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

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

	September 30, 2012	December 31, 2011
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 114	$ 109
Restricted cash equivalents	14	11
Accounts receivable, less allowance for uncollectible accounts of $42 million and $49 million, respectively	940	929
Inventories	168	132
Derivative assets	2	5
Prepayments of income taxes	53	74
Deferred income tax assets, net	43	59
Prepaid expenses and other	153	120
Total Current Assets	1,487	1,439
INVESTMENTS AND OTHER ASSETS		
Goodwill	1,407	1,407
Regulatory assets	2,421	2,196
Investment in finance leases held in trust	1,226	1,349
Income taxes receivable	218	84
Restricted cash equivalents	15	15
Assets and accrued interest related to uncertain tax positions	76	37
Derivative assets	8	—
Other	164	163
Total Investments and Other Assets	5,535	5,251
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	13,349	12,855
Accumulated depreciation	(4,749)	(4,635)
Net Property, Plant and Equipment	8,600	8,220
TOTAL ASSETS	$ 15,622	$ 14,910

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

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

	September 30, 2012	December 31, 2011
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 848	$ 732
Current portion of long-term debt and project funding	118	112
Accounts payable and accrued liabilities	548	549
Capital lease obligations due within one year	12	8
Taxes accrued	97	110
Interest accrued	84	47
Liabilities and accrued interest related to uncertain tax positions	9	3
Derivative liabilities	13	26
Other	274	274
Total Current Liabilities	2,003	1,861
DEFERRED CREDITS		
Regulatory liabilities	528	526
Deferred income taxes, net	3,213	2,863
Investment tax credits	22	22
Pension benefit obligation	299	424
Other postretirement benefit obligations	450	469
Liabilities and accrued interest related to uncertain tax positions	6	32
Derivative liabilities	10	6
Other	189	191
Total Deferred Credits	4,717	4,533
LONG-TERM LIABILITIES		
Long-term debt	4,100	3,794
Transition bonds issued by ACE Funding	267	295
Long-term project funding	12	13
Capital lease obligations	70	78
Total Long-Term Liabilities	4,449	4,180
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
EQUITY		
Common stock, $.01 par value, 400,000,000 shares authorized, 229,438,681 and 227,500,190 shares outstanding, respectively	2	2
Premium on stock and other capital contributions	3,369	3,325
Accumulated other comprehensive loss	(47)	(63)
Retained earnings	1,129	1,072
Total Equity	4,453	4,336
TOTAL LIABILITIES AND EQUITY	$ 15,622	$ 14,910

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

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

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 242	$ 238
Income from discontinued operations	—	(1)
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	343	325
Non-cash rents from cross-border energy lease investments	(39)	(35)
Gain on early termination of finance leases held in trust	(39)	(39)
Deferred income taxes	279	165
Net unrealized (gains) losses on derivatives	(20)	11
Impairment losses	5	—
Other	(11)	(9)
Changes in:		
Accounts receivable	(26)	86
Inventories	(36)	(20)
Prepaid expenses	(30)	(14)
Regulatory assets and liabilities, net	(104)	(108)
Accounts payable and accrued liabilities	2	(106)
Pension contributions	(200)	(110)
Pension benefit obligation, excluding contributions	49	39
Cash collateral related to derivative activities	76	5
Income tax-related prepayments, receivables and payables	(133)	(14)
Interest accrued	38	34
Other assets and liabilities	23	40
Conectiv Energy net assets held for sale	—	44
Net Cash From Operating Activities	419	531
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(888)	(639)
Department of Energy capital reimbursement awards received	25	27
Proceeds from early termination of finance leases held in trust	202	161
Changes in restricted cash equivalents	(2)	(10)
Net other investing activities	1	(10)
Net Cash Used By Investing Activities	(662)	(471)
FINANCING ACTIVITIES		
Dividends paid on common stock	(185)	(183)
Common stock issued for the Dividend Reinvestment Plan and employee-related compensation	40	36
Redemption of preferred stock of subsidiaries	—	(6)
Issuances of long-term debt	450	235
Reacquisitions of long-term debt	(165)	(60)
Issuances of short-term debt, net	116	11
Cost of issuances	(8)	(10)
Net other financing activities	—	(1)
Net Cash From Financing Activities	248	22
Net Increase in Cash and Cash Equivalents	5	82
Cash and Cash Equivalents at Beginning of Period	109	21
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 114	$ 103
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes, net	$ (2)	$ —
Non-cash activities:		
Reclassification of property, plant and equipment to regulatory assets	90	—
Reclassification of asset removal costs regulatory liability to accumulated depreciation	61	—

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

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

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Accumulated Other Comprehensive Loss	Retained Earnings	Total
BALANCE, DECEMBER 31, 2011	227,500,190	$ 2	$ 3,325	$ (63)	$ 1,072	$4,336
Net income	—	—	—	—	68	68
Other comprehensive income	—	—	—	8	—	8
Dividends on common stock ($0.27 per share)	—	—	—	—	(61)	(61)
Issuance of common stock:						
Original issue shares, net	319,037	—	9	—	—	9
Shareholder DRP original shares	424,888	—	8	—	—	8
Net activity related to stock-based awards	—	—	(2)	—	—	(2)
BALANCE, MARCH 31, 2012	228,244,115	2	3,340	(55)	1,079	4,366
Net income	—	—	—	—	62	62
Other comprehensive income	—	—	—	4	—	4
Dividends on common stock ($0.27 per share)	—	—	—	—	(62)	(62)
Issuance of common stock:						
Original issue shares, net	186,820	—	3	—	—	3
Shareholder DRP original shares	420,880	—	8	—	—	8
Net activity related to stock-based awards	—	—	3	—	—	3
BALANCE, JUNE 30, 2012	228,851,815	2	3,354	(51)	1,079	4,384
Net income	—	—	—	—	112	112
Other comprehensive income	—	—	—	4	—	4
Dividends on common stock ($0.27 per share)	—	—	—	—	(62)	(62)
Issuance of common stock:						
Original issue shares, net	177,383	—	4	—	—	4
Shareholder DRP original shares	409,483	—	8	—	—	8
Net activity related to stock-based awards	—	—	3	—	—	3
BALANCE, SEPTEMBER 30, 2012	229,438,681	$ 2	$ 3,369	$ (47)	$ 1,129	$4,453

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

<u>NOTES TO CONSOLIDATED FINANCIAL STATEMENTS</u>

PEPCO HOLDINGS, INC.

(1) <u>ORGANIZATION</u>

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:

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

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

Through Pepco Energy Services, Inc. and its subsidiaries (collectively, Pepco Energy Services), PHI provides energy savings performance contracting services, primarily to commercial, industrial and government customers. Pepco Energy Services is in the process of winding down its competitive electricity and natural gas retail supply business. 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, 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 these Notes to the consolidated financial statements, these supply service obligations are referred to generally as Default Electricity Supply.

Pepco Energy Services

Pepco Energy Services is engaged in the following businesses:

- providing energy efficiency services principally to federal, state and local government customers, and designing, constructing and operating combined heat and power and central energy plants,
- providing high voltage electric 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, and
- providing retail customers electricity and natural gas under its remaining contractual obligations.

Pepco Energy Services deactivated its Buzzard Point oil-fired generation facility on May 31, 2012 and its Benning Road oil-fired generation facility on June 30, 2012.

In December 2009, PHI announced the wind-down of the retail energy supply component of the Pepco Energy Services business. Pepco Energy Services is implementing this wind-down by not entering into any new retail energy supply contracts while continuing to perform under its existing supply contracts through their respective expiration dates, the last of which is June 1, 2014. The retail energy supply business has historically generated a substantial portion of the operating revenues and net income of the Pepco Energy Services segment. Operating revenues related to the retail energy supply business for the three months ended September 30, 2012 and 2011 were $77 million and $222 million, respectively, while operating income for the same periods was $13 million and $5 million, respectively. Operating revenues related to the retail energy supply business for the nine months ended September 30, 2012 and 2011 were $349 million and $765 million, respectively, while operating income for the same periods was $44 million and $21 million, respectively.

In connection with the operation of the retail energy supply business, Pepco Energy Services provided letters of credit of less than $1 million and posted net cash collateral of $38 million as of September 30, 2012. These collateral requirements, which are based on existing wholesale energy purchase and sale contracts and current market prices, will decrease as the contracts expire, with the collateral expected to be fully released by June 1, 2014. The energy services business will not be affected by the wind-down of the retail energy supply business.

Other Business Operations

Through its subsidiary Potomac Capital Investment Corporation (PCI), PHI maintains a portfolio of cross-border energy lease investments. This activity constitutes a third operating segment for financial reporting purposes, which is designated as "Other Non-Regulated." For a 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.

Discontinued Operations

In April 2010, the Board of Directors approved a plan for the disposition of PHI's competitive wholesale power generation, marketing and supply business, which had been conducted through subsidiaries of Conectiv Energy Holding Company (collectively Conectiv Energy). On July 1, 2010, PHI completed the sale of Conectiv Energy's wholesale power generation business to Calpine Corporation (Calpine) for $1.64 billion. The disposition of all of Conectiv Energy's remaining assets and businesses, consisting of its load service supply contracts, energy hedging portfolio, certain tolling agreements and other assets not included in the Calpine sale, has been completed. The former operations of Conectiv Energy have been accounted for as a discontinued operation and no longer constitute a separate segment for financial reporting purposes.

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

Pepco Holdings' unaudited consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. Therefore, these consolidated financial statements should be read along with the annual consolidated financial statements included in PHI's annual report on Form 10-K for the year ended December 31, 2011, as amended to include the executive compensation and other information required by Part III of Form 10-K (which information originally had been omitted as permitted by that form). In the opinion of PHI's management, the consolidated financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly Pepco Holdings' financial condition as of September 30, 2012, in accordance with GAAP. The year-end December 31, 2011 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 nine months ended September 30, 2012 may not be indicative of PHI's results that will be realized for the full year ending December 31, 2012.

Use of Estimates

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

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset and goodwill impairment calculations, fair value calculations for derivative instruments, pension and other postretirement benefit assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of 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, 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.

Storm Restoration Costs

On June 29, 2012, the respective service territories of Pepco, DPL and ACE were affected by a rapidly moving thunderstorm with hurricane-force winds, known as a "derecho," which resulted in widespread customer outages in each of the service territories. The derecho caused extensive damage to the electric transmission and distribution systems of Pepco, DPL and ACE. Storm restoration activity commenced immediately following the storm and continued into July 2012, with the majority of the incremental storm restoration costs occurring in the third quarter of 2012.

Total incremental storm restoration costs incurred by PHI through September 30, 2012 were $81 million, with $40 million incurred for repair work and $41 million incurred as capital expenditures. Costs incurred for repair work of $35 million were deferred as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey, and $5 million was charged to Other operation and maintenance expense. As of September 30, 2012, total incremental storm restoration costs include $27 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. PHI's utility subsidiaries will be pursuing recovery of the incremental storm restoration costs in their respective jurisdictions during the next cycle of distribution base rate cases.

General and Auto Liability

During the second quarter of 2011, PHI's utility subsidiaries reduced their self-insurance reserves for general and auto liability claims by approximately $4 million, based on obtaining an actuarial estimate of the unpaid losses attributed to general and auto liability claims for each of PHI's utility subsidiaries at June 30, 2011. A similar evaluation was performed in the third quarter of 2012 and no material adjustments were made to these reserves.

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. As of September 30, 2012, PHI was 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.

Net purchase activities with the NUGs for the three months ended September 30, 2012 and 2011 were approximately $56 million and $57 million, respectively, of which approximately $53 million and $55 million, respectively, consisted of power purchases under the PPAs. Net purchase activities with the NUGs for the nine months ended September 30, 2012 and 2011 were approximately $156 million and $169 million, respectively, of which approximately $151 million and $159 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 September 30, 2012, PHI, through its DPL subsidiary, has entered into 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 are 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 PPAs. 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, in each case at the rates primarily fixed by the PPA. DPL's purchases under the three wind PPAs totaled $4 million and $3 million for the three months ended September 30, 2012 and 2011, respectively, and $20 million and $12 million for the nine months ended September 30, 2012 and 2011, 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 $1 million and $2 million for the three and nine months ended September 30, 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. In June 2012, a 3 MW fuel cell generation facility was placed into service under the tariff. DPL billed less than $1 million to distribution customers during the three and nine months ended September 30, 2012. A 27 MW fuel cell generation facility is expected to be placed into service in 5 MW increments beginning in January 2013. DPL is accounting for this arrangement as an agency transaction.

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 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. The annual share of payments to or receipts by ACE and the other EDCs is based upon each company's annual proportion of the total New Jersey load attributable to all EDCs, which is currently estimated to be approximately 15 percent for ACE. The NJBPU has approved full recovery from distribution customers of payments made by ACE and the other EDCs, and distribution customers would be entitled to any payments received from the generation companies. For additional discussion about the SOCAs, see Note (7), "Regulatory Matters."

In May 2012, all three generation companies under the SOCAs bid into the PJM 2015-2016 capacity auction and two of the generators cleared that capacity auction. ACE recorded a derivative asset (liability) for the estimated fair value of each SOCA and recorded an offsetting regulatory liability (asset) as described in more detail in Note (13), "Derivative Instruments and Hedging Activities," and Note (14), "Fair Value Disclosures." FASB guidance on derivative accounting and the accounting for regulated operations would apply to ACE's obligations under the third SOCA once the related capacity has cleared a PJM auction. The next PJM capacity auction is scheduled for May 2013. PHI has concluded that consolidation is not required for the SOCAs under the FASB guidance on the consolidation of variable interest entities.

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 nine months ended September 30, 2012.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco Holdings' gross revenues were $110 million and $111 million for the three months ended September 30, 2012 and 2011, respectively, and $293 million and $302 million for the nine months ended September 30, 2012 and 2011, 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:

Pepco Energy Services Derivative Accounting Reclassifications and Adjustments

In the third quarter of 2012, PHI recorded an adjustment to reclassify certain 2011 mark-to-market losses from Operating revenue to Fuel and purchased energy expenses for Pepco Energy Services. The reclassification resulted in an increase in Operating revenue and an increase in Fuel and purchased energy expenses of $5 million and $12 million for the three and nine months ended September 30, 2011, respectively. This reclassification did not result in a change to net income.

During the first quarter of 2011, PHI recorded an adjustment associated with an increase in the value of certain derivatives from October 1, 2010 to December 31, 2010, which had been erroneously recorded in other comprehensive income at December 31, 2010. This adjustment resulted in an increase in revenue and pre-tax earnings of $2 million for the nine months ended September 30, 2011.

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 nine months ended September 30, 2012.

DPL Default Electricity Supply Revenue and Cost Adjustments

During 2011, DPL recorded adjustments to correct certain errors associated with the accounting for Default Electricity Supply revenue and costs. These adjustments primarily arose from the under-recognition of allowed returns on the cost of working capital and resulted in a pre-tax decrease in Other operation and maintenance expense of $1 million and $9 million for the three and nine months ended September 30, 2011, respectively.

Income Tax Expense Adjustments

During the first quarter of 2011, Pepco recorded an adjustment to correct certain income tax errors related to prior periods associated with interest on uncertain tax positions. The adjustment resulted in an increase in Income tax expense of $1 million for the nine months ended September 30, 2011.

During the second quarter of 2011, ACE completed a reconciliation of its deferred taxes associated with certain regulatory assets and recorded adjustments that resulted in an increase to Income tax expense of $1 million for the nine months ended September 30, 2011.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Fair Value Measurements and Disclosures (ASC 820)

The FASB issued new guidance on fair value measurement and disclosures that was effective beginning with PHI's March 31, 2012 consolidated financial statements. The new measurement guidance did not have a material impact on PHI's consolidated financial statements and the new disclosure requirements are in Note (14), "Fair Value Disclosures," of PHI's consolidated financial statements.

Comprehensive Income (ASC 220)

The FASB issued new disclosure requirements for reporting comprehensive income that were effective beginning with PHI's March 31, 2012 consolidated financial statements. PHI did not have to change the presentation of its comprehensive income because it had already reported comprehensive income in two separate but consecutive statements of income and comprehensive income. PHI also has provided the new required disclosures of the income tax effects of items in other comprehensive income and amounts reclassified from other comprehensive income to income on a quarterly basis in Note (16), "Accumulated Other Comprehensive Loss."

Goodwill (ASC 350)

The FASB issued new guidance that changes the annual and interim assessments of goodwill for impairment. The new guidance modifies the required annual impairment test by giving entities the option to perform a qualitative assessment of whether it is more likely than not that goodwill is impaired before performing a quantitative assessment. The new guidance also amends the events and circumstances that entities should assess to determine whether an interim quantitative impairment test is necessary. As of January 1, 2012, PHI has adopted the new guidance and concluded it did not have a material impact on its consolidated financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosures will include information about the gross exposures 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. The new disclosures are effective beginning with PHI's March 31, 2013 consolidated financial statements. PHI is evaluating the impact of this new guidance on its consolidated financial statements.

(5) SEGMENT INFORMATION

Pepco Holdings' management has identified its operating segments at September 30, 2012 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 nine months ended September 30, 2012 and 2011 is as follows:

	Three Months Ended September 30, 2012 (millions of dollars)				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 1,335	$ 131	$ 13	$ (3)	$ 1,476
Operating Expenses (b)	1,136	125(c)	(38)(d)	(11)	1,212
Operating Income	199	6	51	8	264
Interest Income	—	1	1	(2)	—
Interest Expense	56	—	3	9	68
Other Income (Expenses)	8	1	(1)	1	9
Preferred Stock Dividends	—	—	1	(1)	—
Income Tax Expense	59	3	31(e)	—	93
Net Income (Loss) from Continuing Operations	92	5	16(d)	(1)	112
Total Assets	12,039	442	1,483	1,658	15,622
Construction Expenditures	$ 289	$ 1	$ —	$ 9	$ 299

(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 $(3) million for Operating Revenue, $(4) million for Operating Expenses, $(7) million for Interest Income, $(5) million for Interest Expense and $(1) million for Preferred Stock Dividends.

(b) Includes depreciation and amortization expense of $122 million, consisting of $114 million for Power Delivery, $2 million for Pepco Energy Services and $6 million for Corporate and Other.

(c) Includes impairment losses of $2 million pre-tax ($1 million after-tax) at Pepco Energy Services associated with the combustion turbines at Buzzard Point.

(d) Includes $39 million pre-tax ($9 million after-tax) gain from the early termination of finance leases held in trust.

(e) Includes a $16 million reversal of previously recognized tax benefits associated with the early termination of finance leases held in trust.

	Three Months Ended September 30, 2011 (millions of dollars)				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 1,329	$ 317	$ 7	$ (5)	$ 1,648
Operating Expenses (b)	1,167	305	2	(21)	1,453
Operating Income	162	12	5	16	195
Interest Income	1	1	—	(2)	—
Interest Expense	53	1	3	7	64
Other Income (Expenses)	7	1	(3)	(1)	4
Preferred Stock Dividends	—	—	1	(1)	—
Income Tax Expense (Benefit)	51	5	(7)	6	55
Net Income from Continuing Operations	66	8	5	1	80
Total Assets (excluding Assets Held For Sale)	11,015	611	1,467	1,475	14,568
Construction Expenditures	$ 239	$ 4	$ —	$ 9	$ 252

(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, $(6) million for Operating Expenses, $(7) million for Interest Income, $(6) million for Interest Expense and $(1) million for Preferred Stock Dividends.

(b) Includes depreciation and amortization expense of $115 million, consisting of $107 million for Power Delivery, $4 million for Pepco Energy Services and $4 million for Corporate and Other.

	Nine Months Ended September 30, 2012 (millions of dollars)				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 3,374	$ 544	$ 40	$ (11)	$ 3,947
Operating Expenses (b)	2,950	507(c)	(35)(d)	(30)	3,392
Operating Income	424	37	75	19	555
Interest Income	—	1	3	(4)	—
Interest Expense	162	1	10	25	198
Other Income	24	1	—	2	27
Preferred Stock Dividends	—	—	2	(2)	—
Income Tax Expense	93	15	33(e)	1	142
Net Income (Loss) from Continuing Operations	193	23	33(d)	(7)	242
Total Assets	12,039	442	1,483	1,658	15,622
Construction Expenditures	$ 854	$ 11	$ —	$ 23	$ 888

(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 $(11) million for Operating Revenue, $(11) million for Operating Expenses, $(18) million for Interest Income, $(15) million for Interest Expense and $(2) million for Preferred Stock Dividends.

(b) Includes depreciation and amortization expense of $343 million, consisting of $313 million for Power Delivery, $12 million for Pepco Energy Services, $1 million for Other Non-Regulated and $17 million for Corporate and Other.

(c) Includes impairment losses of $5 million pre-tax ($3 million after-tax) at Pepco Energy Services associated primarily with an investment in a landfill gas-fired electric generation facility, and the combustion turbines at Buzzard Point.

(d) Includes $39 million pre-tax ($9 million after-tax) gain from the early termination of finance leases held in trust.

(e) Includes a $16 million reversal of previously recognized tax benefits associated with the early termination of finance leases held in trust.

	Nine Months Ended September 30, 2011 (millions of dollars)				
	Power Delivery	Pepco Energy Services	Other Non-Regulated	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 3,671	$1,005	$ 35	$ (13)	$ 4,698
Operating Expenses (b)	3,255	964	(34)(c)	(33)	4,152
Operating Income	416	41	69	20	546
Interest Income	1	1	2	(4)	—
Interest Expense	155	3	10	21	189
Other Income (Expenses)	23	3	(4)	1	23
Preferred Stock Dividends	—	—	2	(2)	—
Income Tax Expense (d)	100	16	25	2	143
Net Income (Loss) from Continuing Operations	185	26	30(c)	(4)	237
Total Assets (excluding Assets Held For Sale)	11,015	611	1,467	1,475	14,568
Construction Expenditures	$ 603	$ 11	$ —	$ 25	$ 639

(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 $(13) million for Operating Revenue, $(12) million for Operating Expenses, $(17) million for Interest Income, $(15) million for Interest Expense and $(2) million for Preferred Stock Dividends.

(b) Includes depreciation and amortization expense of $325 million, consisting of $301 million for Power Delivery, $13 million for Pepco Energy Services, $1 million for Other Non-Regulated and $10 million for Corporate and Other.

(c) Includes $39 million pre-tax ($3 million after-tax) gain from the early termination of finance leases held in trust.

(d) Includes tax benefits of $14 million for Power Delivery primarily associated with an interest benefit related to federal tax liabilities and a $22 million reversal of previously recognized tax benefits for Other Non-Regulated associated with the early termination of finance leases held in trust.

(6) GOODWILL

PHI's goodwill balance of $1.4 billion was unchanged during the nine months ended September 30, 2012. 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, 2011 indicated that goodwill was not impaired. For the nine months ended September 30, 2012, 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, 2012.

(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. The Maryland Public Service Commission (MPSC) later modified the BSA in Maryland so that revenues lost as a result of major storm outages are not collected through the BSA if electric service is not restored to the pre-major storm levels within 24 hours of the start of a major storm. For further information on the BSA in Maryland, see "Maryland – BSA Proceeding" below.

- A modified fixed variable rate design (MFVRD) has been approved in concept for DPL electric and natural gas service in Delaware, but the implementation has been deferred by the DPSC pending the development of an implementation plan and a customer education plan, as well as the resolution of various matters relating to development of a statewide energy efficiency plan and attendant legislation.
- 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 approved in concept in Delaware provides for a fixed customer charge (i.e., not tied to the customer's volumetric consumption) 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.

In an effort to reduce the shortfall in revenues due to the delay in time or lag between when costs are incurred and when they are reflected in rates (regulatory lag), Pepco and DPL proposed, in each of their respective jurisdictions, (i) a reliability investment recovery mechanism (RIM) to recover reliability-related capital expenditures incurred between base rate cases, and (ii) the use of fully forecasted test years in future rate cases (which are comprised of forward-looking costs in lieu of historical test years, and if approved, would be more reflective of current costs and would mitigate the effects of regulatory lag). The status of these proposals is discussed below in connection with the discussions of Pepco's and DPL's respective electric distribution base rate proceedings.

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 2011, DPL made its 2011 GCR filing. The filing includes the second year of the effect of a two-year amortization of under-recovered gas costs proposed by DPL in its 2010 GCR filing (the settlement approved by the DPSC in its 2010 GCR case included only the first year of the proposed two-year amortization). The rates proposed in the 2011 GCR would result in a GCR decrease of approximately 5.6%. On August 21, 2012, the DPSC issued a final order approving the rates as filed.

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.

Electric Distribution Base Rates

On December 2, 2011, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $31.8 million, based on a requested return on equity (ROE) of 10.75%, and requested approval of implementation of the MFVRD. The filing included a request for DPSC approval of a RIM and the use of fully forecasted test years in future DPL rate cases. On January 10, 2012, the DPSC entered an order suspending the full increase and allowing a temporary rate increase of $2.5 million to go into effect on January 31, 2012, subject to refund and pending final DPSC approval. On July 3, 2012, in accordance with an agreement with DPSC staff, DPL placed an additional $22.3 million of the requested rate increase into effect, also subject to refund and pending final DPSC order. On August 17, 2012, DPL and the other parties to the proceeding entered into a proposed settlement that provides for an annual rate increase of $22 million, based on an ROE of 9.75%. The settlement agreement also permits DPL to collect from its standard offer service (SOS) customers (retail customers who do not elect to purchase electricity from a competitive supplier but instead purchase such electricity from DPL at regulated rates) approximately $3.4 million related to various state and local taxes that were assessed upon DPL's SOS customers, but actually paid by DPL rather than by the SOS customers upon whom they were assessed. These taxes would be collected over a three-year period. In addition, the settlement agreement allows for the phase-in of the recovery of costs associated with DPL's advanced metering infrastructure (AMI) project. The settlement agreement does not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it does provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag. The settlement agreement is subject to approval by the DPSC. Once approved by the DPSC, DPL will refund the billed amounts that exceeded the increase approved by the DPSC. DPL expects the DPSC to issue a decision on the settlement agreement in the fourth quarter of 2012.

District of Columbia

On July 8, 2011, Pepco filed an application with the District of Columbia Public Service Commission (DCPSC) to increase its electric distribution base rates by approximately $42 million annually, based on a requested ROE of 10.75%, of which approximately $9 million was sought so that Pepco could recover its costs associated with the AMI project. The filing included a request for DCPSC approval of a RIM and the use of fully forecasted test years in future Pepco rate cases. On September 26, 2012, the DCPSC issued its decision approving a rate increase of $24 million, based on an ROE of 9.5%, of which approximately $9 million allows Pepco to recover costs associated with the AMI project. The DCPSC denied Pepco's request for approval of a RIM, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases. In addition, the DCPSC approved an adjustment by Pepco to normalize operation and maintenance expenses associated with storm restoration efforts to its three-year average, but added approximately $2 million of costs associated with Hurricane Irene from August 2011 in the calculation of the three-year average storm costs. On October 31, 2012, the District of Columbia Office of the People's Counsel filed a motion with the DCPSC for reconsideration of a portion of the order, objecting to (i) the percentage of the rate increase allocated to residential customers, and (ii) the decision not to adjust Pepco's base rates downward because of the quality and reliability of Pepco's electric distribution service. Pepco also filed a motion for reconsideration and clarification on that date (i) objecting to provisions requiring Pepco to perform studies and report certain information three months in advance of its next base rate case filing, and (ii) requesting clarification concerning the timing of certain reporting requirements. The filing of these motions does not stay the order or delay the rate increase from going into effect.

Maryland

DPL Electric Distribution Base Rates

On December 9, 2011, DPL submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $25.2 million (subsequently reduced by DPL to $23.5 million), based on a requested ROE of 10.75%. The filing included a request for MPSC approval of a RIM and the use of fully forecasted test years in future DPL rate cases. On July 20, 2012, the MPSC issued an order approving an annual rate increase of approximately $11.3 million, based on an ROE of 9.81%. The MPSC reduced DPL's depreciation rates, which is expected to lower annual depreciation and amortization expenses by an estimated $4.1 million. The order did not approve DPL's request to implement a RIM and did not endorse the use by DPL of fully forecasted test years in future rate cases. The order also authorizes DPL to recover in rates over a five-year period $4.3 million of the $4.6 million of incremental storm restoration costs associated with Hurricane Irene that had been deferred previously as a regulatory asset by DPL. The new revenue rates and lower depreciation rates were effective on July 20, 2012. DPL has determined not to appeal the MPSC order.

Pepco Electric Distribution Base Rates

On December 16, 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%. The filing included a request for MPSC approval of a RIM and the use of fully forecasted test years in future Pepco rate cases. On July 20, 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. The MPSC also directed Pepco to reduce the amount of the rate increase by approximately $1.6 million, the annual costs of certain energy advisory programs, resulting in a final rate increase of approximately $16.5 million. Pepco would be required to seek recovery of these annual costs through the EmPower

Maryland Program. The MPSC reduced Pepco's depreciation rates, which is expected to lower annual depreciation and amortization expenses by an estimated $27.3 million. The order did not approve Pepco's request to implement a RIM and did not endorse the use by Pepco of fully forecasted test years in future rate cases. The order authorizes Pepco to recover in rates over a five-year period $18.5 million of incremental storm restoration costs associated with major weather events in 2011, including $9.7 million of the $9.9 million of incremental storm restoration costs associated with Hurricane Irene that had been deferred previously as a regulatory asset by Pepco and $8.8 million of incremental storm restoration costs incurred by Pepco associated with a severe winter storm in the first quarter of 2011 that had been expensed previously through other operation and maintenance expense in 2011. The incremental storm restoration costs of $8.8 million were reversed and deferred as a regulatory asset in the third quarter of 2012. The order also authorizes Pepco to recover the actual cost of AMI meters installed during the 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 proven to be cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. Pepco has determined not to appeal the MPSC order. The Maryland Office of People's Counsel has sought rehearing on the portion of the order allowing Pepco to recover the costs of installed AMI meters; that motion remains pending.

BSA Proceeding

As in effect for electric utilities in Maryland prior to October 26, 2012, including Pepco and DPL, a utility was not permitted to collect through the BSA distribution revenues lost as a result of major storm outages, beginning 24 hours after the commencement of a major storm, if electric service is not restored to the pre-major storm levels within 24 hours of the start of the storm. On October 26, 2012, the MPSC issued an order that no longer permits certain Maryland utilities, including Pepco and DPL, to collect a BSA surcharge for revenues lost during the first 24 hours of a major storm.

New Jersey

Electric Distribution Base Rates

On August 5, 2011, ACE filed a petition with the NJBPU to increase its electric distribution rates by the net amount of approximately $54.6 million (which was increased to approximately $74.3 million on February 24, 2012, to reflect the 2011 test year), based on a requested ROE of 10.75%. The modified net increase consists of a rate increase proposal of approximately $90.3 million, less a deduction from base rates of approximately $16 million through a credit rider expected to expire August 31, 2013, which is designed to refund to customers certain excess depreciation reserve funds as previously directed by the NJBPU (the Excess Depreciation Rider). ACE also proposed an increase of approximately $6.3 million in sales-and-use taxes related to the increase in base rates. On October 23, 2012, the NJBPU approved a stipulation of settlement signed by the parties (the New Jersey Settlement), which provides for an annual increase in ACE's electric distribution base rates by the net amount of approximately $28 million, based on an ROE that, as part of the overall settlement, is deemed to be 9.75%. The net increase consists of a rate increase of approximately $44 million, less a deduction from base rates of approximately $16 million through the Excess Depreciation Rider. Upon expiration of the Excess Depreciation Rider, ACE will not realize an increase in operating income because the resulting increase in revenues will be offset by a substantially similar increase in depreciation expense. The New Jersey Settlement also provides for an increase of approximately $2 million in sales-and-use taxes related to the increase in base rates, and allows ACE to fully amortize over a three-year period the approximately $7.7 million in costs incurred as a result of Hurricane Irene in August 2011. The new rates will become effective for utility services rendered on and after November 1, 2012.

Infrastructure Investment Program

In July 2009, the NJBPU approved certain rate recovery mechanisms in connection with ACE's Infrastructure Investment Program (the IIP). In exchange for the increase in infrastructure investment, the NJBPU, through the IIP, allowed recovery by ACE of its infrastructure investment capital expenditures through a special rate outside the normal rate recovery mechanism of a base rate filing. The IIP was designed to stimulate the New Jersey economy and provide incremental employment in ACE's service territory by increasing the infrastructure expenditures to a level above otherwise normal budgeted levels. In an October 18, 2011 petition (subsequently amended December 16, 2011) filed with the NJBPU, ACE requested an extension and expansion to the IIP. The New Jersey Settlement provides for full cost recovery of ACE's initial IIP, but requires ACE to withdraw its request for extension and expansion to the IIP, without prejudice to file such request again in the future.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012, ACE filed 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 that fund several statewide social programs 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. The net impact of adjusting the charges as proposed (consisting of both the annual impact of the proposed 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, 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. On June 18, 2012, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates to go into effect on July 1, 2012. The rates are deemed "provisional" because ACE's filing will not be updated for actual revenues and expenses (if necessary) for May and June 2012 until after July 1, 2012 and a review of the final underlying costs for reasonableness and prudency will be completed after such filing.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether the EDCs in Maryland 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 certain Maryland EDCs, including Pepco and DPL, 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 acknowledges certain of the EDCs' concerns about the requirements of the contract and directs them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specifies that the EDCs entering into the contract will recover the associated costs, in amounts proportional to their relative SOS loads, through surcharges on their respective SOS customers.

Until the final form of the contract with the winning bidder and associated cost recovery are approved, PHI cannot predict (i) the extent of the negative effect that the order and, once finalized, the contract for new generation, may have on PHI's, Pepco's and DPL's balance sheets, as well as their 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 order on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

On April 27, 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the Northern 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. On May 4, 2012, Pepco, DPL, and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These appeals have been consolidated in the Circuit Court for Baltimore City and are set for hearing on January 24, 2013.

Maryland Governor's Grid Resiliency 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 the Task Force 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 and DPL are currently evaluating the report and its recommendations to determine what effect, if any, they may have on proposals to be made in their future electric distribution base rate cases in Maryland. The form and substance of any such proposals will also depend, in part, on how the MPSC responds to the report and the governor's request.

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 based on concerns about the potential cost to distribution customers. In May 2011, the NJBPU denied a joint motion for reconsideration of its order requiring each of the EDCs to enter into the SOCAs. In June 2011, ACE and the other EDCs filed appeals related to the NJBPU orders with the Appellate Division of the New Jersey Superior Court. On March 5, 2012, the court remanded the case to the NJBPU with instructions to refer the case to an Administrative Law Judge for further consideration. The matter has been transmitted by the NJBPU to the Office of Administrative Law and remains pending.

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 constitutionality of the New Jersey law under which the SOCAs were established. On September 28, 2012, the District Court denied motions for summary judgment filed by ACE and the other plaintiffs, as well as cross-motions filed by defendants. The litigation remains pending.

In October 2011 and January 2012, respectively, two of the three generation companies sent notices of dispute under the SOCA to ACE. The notices of dispute alleged that certain actions taken by PJM will have an adverse effect on the generation company's ability to clear their transactions in the PJM auction, which is required for payment under the SOCA. The two generation companies filed separate petitions with the NJBPU seeking to amend their respective SOCAs and, in April 2012, the NJBPU issued an order consolidating the two matters. In May 2012, the NJBPU denied all of the generation companies' requests without prejudice to their right to raise the issues at a later date.

Termination of the MAPP Project

In 2007, PJM (the regional transmission organization that is responsible for planning the transmission grid and coordinating the movement of wholesale electricity within a region consisting of all or parts of 13 states and the District of Columbia) directed PHI to construct a high-voltage interstate transmission line to address the reliability needs of the region's transmission system. In its most recent configuration, the transmission line, which PHI referred to as the Mid-Atlantic Power Pathway (MAPP), would have covered 152 miles, originating at the Possum Point substation in northern Virginia, traversing under the Chesapeake Bay and ending at the Indian River substation in Delaware.

On August 24, 2012, the board of PJM notified PHI, on behalf of its subsidiaries Pepco and DPL, that the MAPP project has been terminated and removed from PJM's regional transmission expansion plan.

As a result of PJM's decision, on October 2, 2012, Pepco and DPL filed with the MPSC a notice withdrawing their pending applications related to the MAPP project. PHI had included in its five-year projected capital expenditures $205 million of MAPP-related expenditures for the period from 2012 to 2016. PHI has updated its five-year projected capital expenditures to remove MAPP-related expenditures to reflect the PJM decision.

As of September 30, 2012, PHI's total capital expenditures for the MAPP project were approximately $101 million. Under the terms of the Federal Energy Regulatory Commission (FERC) order approving an incentive rate for the MAPP project, FERC authorized the recovery of abandoned costs prudently incurred in connection with the MAPP project. Consistent with this order, PHI intends to seek recovery of abandoned MAPP capital expenditures through a filing expected to be submitted to the FERC in the fourth quarter of 2012. The FERC filing is expected to address, among other things, the period over which the abandoned costs are to be recovered and the rate of return on these costs during the recovery period. Under an order issued by the FERC in 2008, PHI has been allowed to include its MAPP capital expenditures in its rate base, earning an incentive rate of return of 12.8% during the construction period.

As of September 30, 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, and reclassified the remaining $90 million of capital expenditures to a regulatory asset. 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 the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

(8) LEASING ACTIVITIES

Investment in Finance Leases Held in Trust

PHI has a portfolio of cross-border energy lease investments (the lease portfolio) consisting of hydroelectric generation facilities, coal-fired electric generation facilities and natural gas distribution networks located outside of the United States. Each lease investment is comprised of a number of leases. As of September 30, 2012 and December 31, 2011, the lease portfolio consisted of six and seven investments with an aggregate book value of $1.2 billion and $1.3 billion, respectively.

During the third quarter of 2012, PHI entered into early termination agreements with two lessees involving all of the leases comprising one of the seven remaining lease investments. The early terminations of the leases were negotiated at the request of the lessees and were completed in September 2012. PHI received net cash proceeds of $202 million (net of a termination payment of $520 million used to retire the non-recourse debt associated with the terminated leases) and recorded a pre-tax gain of $39 million, representing the excess of the net cash proceeds over the carrying value of the lease investments.

During the second quarter of 2011, PHI entered into early termination agreements with two lessees involving all of the leases comprising one of the original eight lease investments and a small portion of the leases comprising a second lease investment. The early terminations of the leases were negotiated at the request of the lessees and were completed in June 2011. PHI received net cash proceeds of $161 million (net of a termination payment of $423 million used to retire the non-recourse debt associated with the terminated leases) and recorded a pre-tax gain of $39 million, representing the excess of the net cash proceeds over the carrying value of the lease investments.

With respect to the terminated leases, PHI had previously made certain business assumptions regarding foreign investment opportunities available at the end of the full lease terms. Because the leases were terminated in each case earlier than full term, management decided not to pursue these opportunities and certain income tax benefits recognized previously were reversed in the amounts of $16 million and $22 million for the nine months ended September 30, 2012 and 2011, respectively. The after-tax gain on the lease terminations was $9 million and $3 million for the nine months ended September 30, 2012 and 2011, respectively, including the income tax benefit reversal and an income tax provision at the statutory Federal rate of $14 million for each early lease termination. PHI has no intent to terminate early any other leases in the lease portfolio. With respect to certain of these remaining leases, management's assumption continues to be that the foreign earnings recognized at the end of the lease term will remain invested abroad.

In the third quarter of 2011, PHI modified its tax cash flow assumptions for two of the investments in the lease portfolio associated with the change in tax laws in the District of Columbia. Accordingly, PHI recalculated the equity investment and recorded a non-cash $7 million pre-tax ($3 million after-tax) charge.

The components of the cross-border energy lease investments as of September 30, 2012 and December 31, 2011 are summarized below:

	September 30, 2012	December 31, 2011
	(millions of dollars)	
Scheduled lease payments to PHI, net of non-recourse debt	$ 1,852	$ 2,120
Less: Unearned and deferred income	(626)	(771)
Investment in finance leases held in trust	1,226	1,349
Less: Deferred income tax liabilities	(738)	(793)
Net investment in finance leases held in trust	$ 488	$ 556

Income recognized from cross-border energy lease investments, excluding the gains on terminated leases discussed above, was comprised of the following for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Pre-tax income from PHI's cross-border energy lease investments (included in Other Revenue)	$ 13	$ 7	$ 39	$ 35
Income tax expense (benefit) related to cross-border energy lease investments	3	(3)	7	7
Net income from PHI's cross-border energy lease investments	$ 10	$ 10	$ 32	$ 28

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 September 30, 2012, 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 September 30, 2012 and December 31, 2011:

Lessee Rating (a)	September 30, 2012	December 31, 2011
	(millions of dollars)	
Rated Entities		
AA/Aa and above	$ 759	$ 737
A	467	612
Total	$ 1,226	$ 1,349

(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 September 30, 2012 and 2011:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
	(millions of dollars)			
Service cost	$ 8	$ 10	$ 2	$ 1
Interest cost	27	27	9	10
Expected return on plan assets	(33)	(32)	(5)	(5)
Amortization of prior service cost (benefit)	1	—	(1)	(1)
Amortization of net actuarial loss	16	11	4	3
Net periodic benefit cost	$ 19	$ 16	$ 9	$ 8

The following Pepco Holdings information is for the nine months ended September 30, 2012 and 2011:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
	(millions of dollars)			
Service cost	$ 26	$ 27	$ 6	$ 4
Interest cost	80	80	26	28
Expected return on plan assets	(99)	(96)	(14)	(14)
Amortization of prior service cost (benefit)	2	(1)	(3)	(3)
Amortization of net actuarial loss	48	35	11	9
Termination benefits	—	—	1	1
Net periodic benefit cost	$ 57	$ 45	$ 27	$ 25

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 PHI's total 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 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. In the first quarter of 2011, Pepco, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $40 million, $40 million and $30 million, which brought plan assets to the funding target level for 2011 under the Pension Protection Act.

(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 among other changes, extended the expiration date of the facility to August 1, 2016. On August 2, 2012, the amended and restated credit agreement 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.

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 initial credit sublimit for PHI is $750 million 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 September 30, 2012.

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.

At September 30, 2012 and December 31, 2011, 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 $1,078 million and $994 million, respectively. PHI's utility subsidiaries had combined cash and unused borrowing capacity under the credit facility of $563 million and $711 million at September 30, 2012 and December 31, 2011, respectively.

Term Loan Agreement

On April 24, 2012, PHI entered into a $200 million term loan agreement, pursuant to which PHI has borrowed (and may not reborrow) $200 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.875%. PHI'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 0.875%. As of September 30, 2012, outstanding borrowings under the loan agreement bore interest at an annual rate of 1.095%, 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 April 23, 2013.

PHI used the net proceeds of the borrowings under the term loan agreement to repay outstanding commercial paper obligations and for general corporate purposes. Under the terms of the term loan agreement, PHI must maintain compliance with specified covenants, including (i) the requirement that PHI 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 PHI or any of its significant subsidiaries. The loan agreement does not include any rating triggers. PHI was in compliance with all covenants under this agreement as of September 30, 2012.

Commercial Paper

PHI, Pepco, DPL and ACE maintain on-going commercial paper programs to address short-term liquidity needs. As of September 30, 2012, 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, Pepco and ACE had $293 million, $134 million and $93 million, respectively, of commercial paper outstanding at September 30, 2012. DPL had no commercial paper outstanding at September 30, 2012. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2012 was 0.87%, 0.42%, 0.43% and 0.42%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2012 was ten, four, four and three days, respectively.

Other Financing Activities

In July 2012, ACE Funding made principal payments of $6 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

On August 6, 2012, DPL redeemed, prior to maturity, $31 million of its 5.20% tax-exempt pollution control refunding revenue bonds due 2019, issued by the Delaware Economic Development Authority for DPL's benefit. Contemporaneously with this redemption, DPL redeemed $31 million of its outstanding 5.20% first mortgage bonds due 2019 that secured the obligations under the pollution control bonds.

On September 28, 2012, ACE redeemed, prior to maturity, $4 million of its 5.60% tax-exempt pollution control revenue bonds due 2025 issued by the Industrial Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit. Contemporaneously with this redemption, ACE redeemed, prior to maturity, $4 million of its outstanding 5.60% first mortgage bonds due 2025 that secured the obligations under the pollution control bonds.

Collateral Requirements of Pepco Energy Services

In the ordinary course of its retail energy supply business, which is in the process of being wound down, Pepco Energy Services entered into various contracts to buy and sell electricity, fuels and related products, including derivative instruments, designed to reduce its financial exposure to changes in the value of its assets and obligations due to energy price fluctuations. These contracts typically have collateral requirements. Depending on the contract terms, the collateral required to be posted by Pepco Energy Services can be of varying forms, including cash and letters of credit.

As of September 30, 2012, Pepco Energy Services had posted net cash collateral of $38 million and letters of credit of less than $1 million. At December 31, 2011, Pepco Energy Services had posted net cash collateral of $112 million and letters of credit of $1 million.

At September 30, 2012 and December 31, 2011, the amount of cash, plus borrowing capacity under PHI's credit facility available to meet the future liquidity needs of Pepco Energy Services, totaled $515 million and $283 million, respectively.

(11) INCOME TAXES

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 72	35.0%	$ 47	35.0%	$ 134	35.0%	$ 133	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	9	4.4	9	6.7	19	5.0	19	5.0
Asset removal costs	(1)	(0.5)	(2)	(1.5)	(8)	(2.1)	(4)	(1.1)
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	5	3.7	(10)	(2.6)	(11)	(2.9)
Cross-border energy lease investments	15	7.3	(5)	(3.7)	13	3.4	15	3.9
Other, net	(2)	(0.8)	1	0.5	(6)	(1.7)	(9)	(2.3)
Consolidated income tax expense related to continuing operations	$ 93	45.4%	$ 55	40.7%	$ 142	37.0%	$ 143	37.6%

Three Months Ended September 30, 2012 and 2011

PHI's consolidated effective income tax rates for the three months ended September 30, 2012 and 2011 were 45.4% and 40.7%, respectively. The increase in the effective rate for the three months ended September 30, 2012 primarily reflects the reversal of income tax benefits associated with cross-border energy lease investments in the third quarter of 2012, partially offset by changes in estimates and interest related to uncertain and effectively settled tax positions recorded in 2011.

As discussed further in Note (8), "Leasing Activities," during the third quarter of 2012, PHI terminated early its interest in certain cross-border energy leases. As a result of the early terminations, PHI reversed $16 million of previously recognized income tax benefits which will not be realized due to the early termination.

Nine Months Ended September 30, 2012 and 2011

PHI's consolidated effective income tax rates for the nine months ended September 30, 2012 and 2011 were 37.0% and 37.6%, respectively. The effective income tax rates for the nine months ended September 30, 2012 and 2011 reflect the reversal of income tax benefits associated with the early termination of cross-border energy leases in the third quarter of 2012 and in the second quarter of 2011 of $16 million and $22 million, respectively, as discussed in Note (8), "Leasing Activities."

In addition, the effective income tax rate for the nine months ended September 30, 2012 includes income tax benefits of $10 million related to uncertain and effectively settled tax positions, primarily due to the effective settlement with the Internal Revenue Service (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. During the nine months ended September 30, 2011, PHI recorded tax benefits of $11 million related to uncertain and effectively settled tax positions, primarily resulting from the settlement with the IRS on interest due on its 1996 through 2002 tax years.

The rate for the nine months ended September 30, 2012 also reflects an increase in deductible asset removal costs for Pepco in 2012 related to a higher level of asset retirements.

(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 September 30, 2012	Three Months Ended September 30, 2011
	(millions of dollars, except per share data)	
Income (Numerator):		
Net income from continuing operations	$ 112	$ 80
Net income from discontinued operations	—	—
Net income	$ 112	$ 80
Shares (Denominator) (in millions):		
Weighted average shares outstanding for basic computation:		
Average shares outstanding	229	226
Adjustment to shares outstanding	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings per Share of Common Stock	229	226
Net effect of potentially dilutive shares (a)	2	—
Weighted Average Shares Outstanding for Computation of Diluted Earnings per Share of Common Stock	231	226
Basic and Diluted Earnings per Share		
Earnings per share of common stock from continuing operations	$ 0.49	$ 0.35
Earnings per share of common stock from discontinued operations	—	—
Basic and diluted earnings per share	$ 0.49	$ 0.35

(a) The number of options to purchase shares of common stock that were excluded from the calculation of diluted EPS because they were anti-dilutive was zero and 119,766 for the three months ended September 30, 2012 and 2011, respectively.

	Nine Months Ended September 30, 2012	2011
	(millions of dollars, except per share data)	
Income (Numerator):		
Net income from continuing operations	$ 242	$ 237
Net income from discontinued operations	—	1
Net income	$ 242	$ 238
Shares (Denominator) (in millions):		
Weighted average shares outstanding for basic computation:		
Average shares outstanding	228	226
Adjustment to shares outstanding	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	228	226
Net effect of potentially dilutive shares (a)	1	—
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	229	226
Basic and Diluted Earnings per Share		
Earnings per share of common stock from continuing operations	$ 1.06	$ 1.05
Earnings per share of common stock from discontinued operations	—	—
Basic and diluted earnings per share	$ 1.06	$ 1.05

(a) The number of options to purchase shares of common stock that were excluded from the calculation of diluted EPS because they were anti-dilutive was zero and 119,766 for the nine months ended September 30, 2012 and 2011, respectively.

Equity Forward Transaction

On March 5, 2012, PHI entered into an equity forward transaction in connection with a public offering of 17,922,077 shares of PHI common stock. The use of an equity forward transaction substantially eliminates future equity market price risk by fixing a common equity offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until funds are needed in accordance with PHI's capital investment and regulatory plans.

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, to the extent that the transaction is physically settled, PHI would be 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 the amount of cash to be received by PHI upon physical settlement of the equity forward is subject to certain adjustments in accordance with the terms of the equity forward transaction. The equity forward transaction must be settled fully within 12 months of the transaction date. Except in specified circumstances or events that would require physical settlement, PHI is able to elect to settle the equity forward transaction by means of physical, cash or net share settlement, in whole or in part, at any time on or prior to March 5, 2013.

The equity forward transaction had no initial fair value since it was entered into at the then market price of the common stock. PHI will not receive any proceeds from the sale of common stock until the equity forward transaction is settled, and at that time PHI will record the proceeds, if any, in equity. PHI concluded that the equity forward transaction was an equity instrument based on the accounting guidance in ASC 480 and ASC 815 and that it qualified for an exception from derivative accounting under ASC 815 because the forward sale transaction was indexed to its own stock. PHI anticipates settling the equity forward transaction through physical settlement before March 5, 2013.

At September 30, 2012, the equity forward transaction could have been settled with physical delivery of the shares to the forward counterparty in exchange for cash of $317 million. At September 30, 2012, the equity forward transaction could also have been cash settled, with delivery of cash of approximately $18 million to the forward counterparty, or net share settled with delivery of approximately 965,000 shares of common stock to the forward counterparty.

Prior to its settlement, the equity forward transaction will be reflected in PHI's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PHI's common stock used in calculating diluted earnings per share for a reporting period would be increased by the number of shares, if any, that would be issued upon physical settlement of the equity forward transaction less the number of shares that could be purchased by PHI in the market (based on the average market price during that reporting period) using the proceeds receivable upon settlement of the equity forward transaction (based on the adjusted forward sale price at the end of that reporting period). The excess number of shares is weighted for the portion of the reporting period in which the equity forward transaction is outstanding.

Accordingly, before physical or net share settlement of the equity forward transaction, and subject to the occurrence of certain events, PHI anticipates that the forward sale agreement will have a dilutive effect on PHI's earnings per share only during periods when the applicable average market price per share of PHI's common stock is above the per share adjusted forward sale price, as described above. However, if PHI decides to physically or net share settle the forward sale agreement, any delivery by PHI of shares upon settlement could result in dilution to PHI's earnings per share.

For the three and nine months ended September 30, 2012, the equity forward transaction did not have a material dilutive effect on PHI's earnings per share.

(13) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

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

The retail energy supply business of Pepco Energy Services, which is in the process of being wound down, enters into energy commodity contracts in the form of electricity and 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 is 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 become available.

Pepco Energy Services' commodity contracts that are not designated for hedge accounting, do not qualify for hedge accounting, or do not meet the requirements for normal purchase and normal sale accounting, are marked to market through current earnings. Forward contracts that meet the requirements for normal purchase and normal sale accounting are recorded on an accrual basis.

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. 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.

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. Changes in the fair value of the derivatives embedded in the SOCAs are deferred as regulatory assets or 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 September 30, 2012 and December 31, 2011:

	As of September 30, 2012				
Balance Sheet Caption	**Derivatives Designated as Hedging Instruments (a)**	**Other Derivative Instruments**	**Gross Derivative Instruments**	**Effects of Cash Collateral and Netting**	**Net Derivative Instruments**
			(millions of dollars)		
Derivative assets (current assets)	$ —	$ 3	$ 3	$ (1)	$ 2
Derivative assets (non-current assets)	—	8	8	—	8
Total Derivative assets	—	11	11	(1)	10
Derivative liabilities (current liabilities)	(16)	(21)	(37)	24	(13)
Derivative liabilities (non-current liabilities)	(2)	(11)	(13)	3	(10)
Total Derivative liabilities	(18)	(32)	(50)	27	(23)
Net Derivative (liability) asset	$ (18)	$ (21)	$ (39)	$ 26	$ (13)

(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.

Balance Sheet Caption	As of December 31, 2011 Derivatives Designated as Hedging Instruments (a)	Other Derivative Instruments	Gross Derivative Instruments (millions of dollars)	Effects of Cash Collateral and Netting	Net Derivative Instruments
Derivative assets (current assets)	$ 17	$ 6	$ 23	$ (18)	$ 5
Derivative assets (non-current assets)	—	1	1	(1)	—
Total Derivative assets	17	7	24	(19)	5
Derivative liabilities (current liabilities)	(55)	(48)	(103)	77	(26)
Derivative liabilities (non-current liabilities)	(11)	(10)	(21)	15	(6)
Total Derivative liabilities	(66)	(58)	(124)	92	(32)
Net Derivative (liability) asset	$ (49)	$ (51)	$ (100)	$ 73	$ (27)

(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), PHI offsets 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. The amount of cash collateral that was offset against these derivative positions is as follows:

	September 30, 2012	December 31, 2011
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 27	$ 73
Cash collateral received from counterparties with the obligation to return	(1)	—

(a) Includes cash deposits on commodity brokerage accounts

As of September 30, 2012 and December 31, 2011, all PHI cash collateral pledged 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

Pepco Energy Services

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. Pepco Energy Services has elected to no longer apply cash flow hedge accounting to its electricity derivatives and all of its natural gas derivatives. Amounts included in AOCL for these cash flow hedges as of September 30, 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 occur 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 are recognized directly in income.

The cash flow hedge activity during the three and nine months ended September 30, 2012 and 2011 is provided in the tables below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Amount of net pre-tax gain arising during the period included in accumulated other comprehensive loss	$ —	$ —	$ —	$ 2
Amount of net pre-tax loss reclassified into income:				
Effective portion:				
Fuel and purchased energy expense	6	15	31	61
Ineffective portion: (a)				
Revenue	—	1	—	1
Total net pre-tax loss reclassified into income	6	16	31	62
Net pre-tax gain on commodity derivatives included in accumulated other comprehensive loss	$ 6	$ 16	$ 31	$ 64

(a) For the three and nine months ended September 30, 2011, $1 million was reclassified from AOCL to income because the forecasted hedged transactions were deemed probable not to occur.

As of September 30, 2012 and December 31, 2011, Pepco Energy Services had the following types and quantities of outstanding energy commodity contracts employed as cash flow hedges of forecasted purchases and forecasted sales.

	Quantities	
Commodity	September 30, 2012	December 31, 2011
Forecasted Purchases Hedges		
Electricity (MWh)	—	614,560
Forecasted Sales Hedges		
Electricity (MWh)	—	614,560

Power Delivery

All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all of DPL's gains and losses related to hedging activities, are deferred under FASB guidance on regulated operations until recovered from customers based on the fuel adjustment clause approved by the DPSC. The following table indicates the net unrealized derivative losses arising during the period that were deferred as Regulatory assets 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 nine months ended September 30, 2012 and 2011 associated with cash flow hedges:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Net unrealized loss arising during the period	$ —	$ (1)	$ —	$ (1)
Net realized loss recognized during the period	—	(2)	—	(5)

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 September 30, 2012 and 2011. Cash flow hedges are marked to market on the consolidated balance sheets with corresponding adjustments to AOCL for effective cash flow hedges. As of September 30, 2012, $18 million of the losses in AOCL were associated with derivatives that Pepco Energy Services previously designated as cash flow hedges. Although Pepco Energy Services no longer designates these derivatives as cash flow hedges, gains or losses previously deferred in AOCL prior to the decision to discontinue cash flow hedge accounting will remain in AOCL until the hedged forecasted transaction occurs unless it is deemed probable that the hedged forecasted transaction will 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 September 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)	$ 11	$ 10	20 months
Interest rate	10	1	239 months
Total	$ 21	$ 11	

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

Contracts	As of September 30, 2011: Accumulated Other Comprehensive Loss After-tax	As of September 30, 2011: Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Energy commodity (a)	$ 40	$ 28	32 months
Interest rate	10	1	251 months
Total	$ 50	$ 29	

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

Other Derivative Activity

Pepco Energy Services

Pepco Energy Services 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 sheet with the gain or loss for changes in fair value recorded through Fuel and purchased energy expense.

For the three and nine months ended September 30, 2012 and 2011, the amount of the derivative gain (loss) for Pepco Energy Services recognized in income is provided in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Reclassification of mark-to-market to realized on settlement of contracts	$ 5	$ 1	$ 22	$ (1)
Unrealized mark-to-market gain (loss)	3	(5)	(2)	(10)
Total net gain (loss)	$ 8	$ (4)	$ 20	$ (11)

As of September 30, 2012 and December 31, 2011, Pepco Energy Services had the following net outstanding commodity forward contract quantities and net positions on derivatives that did not qualify for hedge accounting:

	September 30, 2012		December 31, 2011	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
Financial transmission rights (MWh)	254,601	Long	267,480	Long
Electric capacity (MW – Days)	—	—	12,920	Long
Electricity (MWh)	261,240	Long	788,280	Long
Natural gas (One Million British Thermal Units (MMBtu))	6,176,711	Long	24,550,257	Long

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 losses arising during the period that were deferred as Regulatory assets 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 nine months ended September 30, 2012 and 2011 associated with these derivatives:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
	(millions of dollars)			
Net unrealized gain (loss) arising during the period	$ 2	$ (4)	$ (3)	$ (6)
Net realized loss recognized during the period	(2)	(3)	(13)	(14)

As of September 30, 2012 and December 31, 2011, 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:

	September 30, 2012		December 31, 2011	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
DPL – Natural gas (MMBtu)	3,571,000	Long	6,161,200	Long
ACE – Capacity (MWs)	180	Long	—	—

Contingent Credit Risk Features

The primary contracts used by Pepco Energy Services and Power Delivery 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 Pepco Energy Services are usually guaranteed by PHI. The obligations of DPL are stand-alone obligations without the guaranty of PHI. If PHI's or 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 debt rating of the holder.

The gross fair values of PHI's derivative liabilities with credit risk-related contingent features as of September 30, 2012 and December 31, 2011, were $14 million and $54 million, respectively, before giving effect to offsetting transactions or collateral under master netting agreements. As of September 30, 2012, PHI had posted no cash collateral against its gross derivative liability, resulting in a net liability of $14 million. As of December 31, 2011, PHI had posted cash collateral of $1 million against its gross derivative liability, resulting in a net liability of $53 million. If PHI's and DPL's debt ratings had been downgraded below investment grade as of September 30, 2012 and December 31, 2011, PHI'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 $56 million and $124 million, respectively, and PHI would have been required to post collateral with the counterparties of approximately $56 million and $123 million, respectively, in addition to that which was posted as of September 30, 2012 and December 31, 2011. The net settlement and additional collateral amounts reflect the effect of offsetting transactions under master netting agreements.

PHI's primary source for posting cash collateral or letters of credit is its credit facility. At September 30, 2012 and December 31, 2011, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the future liquidity needs of PHI and its subsidiaries totaled $1,078 million and $994 million, respectively, of which $515 million and $283 million, respectively, was available to Pepco Energy Services.

(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 September 30, 2012 and December 31, 2011. 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 September 30, 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)				
Electricity (c)	$ 2	$ —	$ 2	$ —
Natural gas (d)	1	1	—	—
Capacity (e)	8	—	—	8
Cash equivalents				
Treasury fund	128	128	—	—
Executive deferred compensation plan assets				
Money market funds	19	19	—	—
Life insurance contracts	58	—	41	17
	$216	$ 148	$ 43	$ 25
LIABILITIES				
Derivative instruments (b)				
Electricity (c)	$ 15	$ —	$ 15	$ —
Natural gas (d)	26	18	—	8
Capacity (e)	9	—	—	9
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
	$ 78	$ 18	$ 43	$ 17

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2012.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents wholesale electricity futures and swaps that are used mainly as part of Pepco Energy Services' retail energy supply business.
(d) Level 1 instruments represent wholesale gas futures and swaps that are used mainly as part of Pepco Energy Services' retail energy supply business and level 3 instruments represent natural gas options purchased by DPL as part of a natural gas hedging program approved by the DPSC, as well as Pepco Energy Services physical basis contracts.
(e) Represents derivatives associated with ACE SOCAs.

Description	Total	Fair Value Measurements at December 31, 2011 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	$114	$ 114	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	18	18	—	—
Life insurance contracts	60	—	43	17
	$192	$ 132	$ 43	$ 17
LIABILITIES				
Derivative instruments (b)				
Electricity (c)	$ 32	$ —	$ 32	$ —
Natural gas (d)	67	50	—	17
Capacity	1	—	1	—
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
	$128	$ 50	$ 61	$ 17

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2011.
(b) The fair value of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents wholesale electricity futures and swaps that are used mainly as part of Pepco Energy Services' retail energy supply business.
(d) Level 1 instruments represent wholesale gas futures and swaps that are used mainly as part of Pepco Energy Services' retail energy supply business and level 3 instruments represent natural gas options purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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

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

PHI's level 2 derivative instruments primarily consist of electricity derivatives at September 30, 2012. Level 2 power swaps are provided by a pricing service that uses liquid trading hub prices or liquid hub prices plus a congestion adder to estimate the fair value at zonal locations within trading hubs.

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 September 30, 2012. 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, natural gas physical basis contracts held by Pepco Energy Services, and capacity under the SOCAs entered into by ACE:

- DPL applies a Black-Scholes model to value its options with inputs, such as the forward price curves, contract prices, contract volumes, the risk-free rate and the 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.
- The natural gas physical basis contracts held by Pepco Energy Services are valued using liquid hub prices plus a congestion adder. The congestion adder is an internally derived adder based on historical data and experience. Pepco Energy Services obtains the liquid hub prices from a third party and reviews the valuation methodologies, inputs, and reasonableness of the congestion adder on a quarterly basis.
- ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external consulting firm 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 table below summarizes 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 September 30, 2012:

Type of Instrument	**Fair Value at September 30, 2012** *(millions of dollars)*		**Valuation Technique**	**Unobservable Input**	**Range**
Natural gas options	$	(7)	Option model	Volatility factor	0.82 - 2.76
Capacity contracts, net		(1)	Discounted cash flow	Discount rate	5% - 9%
Natural gas physical basis contracts		(1)	Market comparable	Congestion adder	$(0.04) - $0.72

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 September 30, 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 nine months ended September 30, 2012 and 2011 are shown below:

	Nine Months Ended September 30, 2012		
	Natural Gas	Life Insurance Contracts	Capacity
		(millions of dollars)	
Beginning balance as of January 1	$ (17)	$ 17	$ —
Total gains (losses) (realized and unrealized):			
Included in income	—	3	—
Included in accumulated other comprehensive loss	—	—	—
Included in regulatory assets	(2)	—	(1)
Purchases	—	—	—
Issuances	—	(3)	—
Settlements	11	—	—
Transfers in (out) of level 3	—	—	—
Ending balance as of September 30	$ (8)	$ 17	$ (1)

	Nine Months Ended September 30, 2011	
	Natural Gas	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ (23)	$ 19
Total gains (losses) (realized and unrealized):		
Included in income	—	5
Included in accumulated other comprehensive loss	—	—
Included in regulatory assets	(6)	—
Purchases	—	—
Issuances	—	(3)
Settlements	11	(4)
Transfers in (out) of level 3	1	—
Ending balance as of September 30	$ (17)	$ 17

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:

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(millions of dollars)	
Total net gains included in income for the period	$ 3	$ 5
Change in unrealized gains relating to assets still held at reporting date	$ 3	$ 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 September 30, 2012 are shown in the table 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 in active markets, but not 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 September 30, 2012			
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)	$5,068	$ 990	$ 3,584	$ 494
Transition Bonds issued by ACE Funding (b)	355	—	355	—
Long-term project funding	14	—	—	14
	$5,437	$ 990	$ 3,939	$ 508

(a) The carrying amount for Long-term debt is $4,177 million as of September 30, 2012.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $306 million as of September 30, 2012.

The estimated fair values of PHI's debt instruments at December 31, 2011 are shown below:

	December 31, 2011	
	Carrying Amount	Fair Value
	(millions of dollars)	
Long-term debt	$ 3,867	$4,577
Transition Bonds issued by ACE Funding	332	380
Long-term project funding	15	15

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

(15) 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. A trial date has been set for May 20, 2013.

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 September 30, 2012 are summarized as follows:

		Legacy Generation			
	Transmission and Distribution	Regulated	Non-Regulated	Other	Total
		(millions of dollars)			
Beginning balance as of January 1	$ 15	$ 8	$ 10	$ 2	$ 35
Accruals	—	—	—	—	—
Payments	—	(1)	—	—	(1)
Ending balance as of September 30	15	7	10	2	34
Less amounts in Other current liabilities	2	2	—	2	6
Amounts in Other deferred credits	$ 13	$ 5	$ 10	$—	$ 28

Conectiv Energy Wholesale Power Generation Sites

On July 1, 2010, PHI sold the Conectiv Energy wholesale power generation business to 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."

On September 14, 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.

The sale of the Conectiv Energy wholesale power generation business to Calpine did not include a coal ash landfill site located at the Edge Moor generating facility, which PHI intends to close. The preliminary estimate of the costs to PHI to close the coal ash landfill ranges from approximately $2 million to $3 million, plus annual post-closure operations, maintenance and monitoring costs, estimated to range between $120,000 and $193,000 per year for 30 years. The amounts accrued by PHI for this matter are included in the table above in the column entitled "Legacy Generation – Non-Regulated."

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 estimates the additional cost for future response measures will be approximately $6 million. ACE believes that EPA sent similar general notice letters to three other companies and various individuals.

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 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. Although PHI cannot at this time 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 and therefore, costs incurred to resolve this matter are not expected to be material.

Benning Road Site

In September 2010, PHI received a letter from EPA stating that EPA and the District of Columbia Department of the Environment (DDOE) have identified 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 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. The court order entering the consent decree requires the parties to submit a written status report to the court on May 24, 2013 regarding the implementation of the requirements of the consent decree and any related plans for remediation. In addition, if the RI/FS has not been completed by May 24, 2013, the status report must provide an explanation and a showing of good cause for why the work has not been completed.

Pepco and Pepco Energy Services submitted a proposed RI/FS work plan in July 2012, and anticipate that the work plan will be approved by DDOE during the fourth quarter of 2012, following which the RI/FS field work will commence.

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.

The release falls within the regulatory jurisdiction of multiple federal and state agencies. 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. Initial discussions with DDOE indicate 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. Based on the 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.

In March 2011, the Virginia Department of Environmental Quality (VADEQ) requested documentation regarding the release and the preparation of an emergency response report, which Pepco submitted to the agency in April 2011. In March 2011, Pepco received a notice of violation from VADEQ and in December 2011, entered into a consent decree with VADEQ, pursuant to which Pepco paid a civil penalty of approximately $40,000. The U.S. Coast Guard assessed a $5,000 penalty against Pepco for the release of oil into the waters of the United States, which Pepco has paid.

During March 2011, EPA conducted an inspection of the Potomac River substation to review compliance with federal regulations regarding Spill Prevention, Control, and Countermeasure (SPCC) plans for facilities using oil-containing equipment in proximity to surface waters. EPA identified several potential violations of the SPCC regulations relating to SPCC plan content, recordkeeping, and secondary containment. As a result of the oil release, Pepco submitted a revised SPCC plan to EPA in August 2011 and 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 and, after receiving such approval, will submit a further revised SPCC plan to EPA. In the meantime, Pepco is continuing to use the aboveground holding tank to manage storm water from the secondary containment system. On April 19, 2012, EPA advised Pepco that it is not seeking civil penalties at this time for alleged non-compliance with SPCC regulations.

The amounts accrued for these matters are included in the table above in the column entitled "Transmission and Distribution."

PHI's Cross-Border Energy Lease Investments

PCI has cross-border energy lease investments involving public utility assets (primarily consisting of hydroelectric generation and coal-fired electric generation facilities and natural gas distribution networks) located outside of the United States. Each of these investments is comprised of multiple leases and each investment is structured as a sale and leaseback transaction commonly referred to by the IRS as a sale-in, lease-out, or SILO transaction. PHI current annual tax benefits from these lease investments are approximately $43 million. As of September 30, 2012, the book value of PHI's investment in its cross-border energy lease investments was approximately $1.2 billion. After taking into consideration the $74 million paid with the 2001-2002 audit (as discussed below), the net federal and state tax benefits received for the remaining leases from January 1, 2001, the earliest year that remains open to audit, to September 30, 2012, has been approximately $479 million. As more fully discussed in Note (8), "Leasing Activities," in the third quarter of 2012 and in the second quarter of 2011, PHI entered into early termination agreements with lessees with respect to a number of leases in the cross-border energy lease portfolio.

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 and 2003-2005 income tax returns, respectively, the IRS disallowed the depreciation and interest deductions in excess of rental income claimed by PHI with respect to each of its cross-border energy lease investments. In addition, the IRS has sought to recharacterize each of the leases as a loan transaction as to which PHI would be subject to original issue discount income. PHI disagreed with the IRS' proposed adjustments and filed protests of these findings 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 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 claim for refund was 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. Absent a settlement, this litigation against the IRS may take several years to resolve. The 2003-2005 income tax return review continues to be in process with the IRS Office of Appeals and at present, is not a part of the U.S. Court of Federal Claims litigation discussed above.

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 estimates that, as of September 30, 2012, it would be obligated to pay approximately $622 million in additional federal and state taxes and $138 million of interest on the remaining leases. The $760 million in additional federal and state taxes and interest is net of the $74 million tax payment made in January 2011. In addition, the IRS could require PHI to pay a penalty of up to 20% on the amount of additional taxes due.

PHI anticipates that any additional taxes that it would be required to pay as a result of the disallowance of prior deductions or a re-characterization of the leases as loans would be recoverable in the form of lower taxes over the remaining terms of the affected leases. Moreover, the entire amount of any additional federal and state tax would not be due immediately, but rather, the federal and state taxes would be payable when the open audit years are closed and PHI amends subsequent tax returns not then under audit. To mitigate the taxes due in the event of a total disallowance of tax benefits, PHI could elect to liquidate all or a portion of its remaining cross-border energy lease investments, which PHI estimates could be accomplished over a period of six months to one year. Based on current market values, PHI estimates that liquidation of the remaining portfolio would generate sufficient cash proceeds to cover the estimated $760 million in federal and state taxes and interest due as of September 30, 2012, in the event of a total disallowance of tax benefits and a recharacterization of the leases as loans. If payments of additional taxes and interest preceded the receipt of liquidation proceeds, the payments would be funded by currently available sources of liquidity.

To the extent that PHI does not prevail in this matter and suffers a disallowance of the tax benefits and incurs imputed original issue discount income, PHI would be required under FASB guidance on leases (ASC 840) to recalculate the timing of the tax benefits generated by the cross-border energy lease investments and adjust the equity value of the investments, which would result in a material non-cash charge to earnings.

District of Columbia Tax Legislation

On September 14, 2012, the District of Columbia Office of Tax and Revenue adopted regulations to implement the mandatory unitary combined reporting method for tax years beginning in 2011. PHI has analyzed these regulations and determined that the regulations did not impact PHI's results of operations for the three and nine months ended September 30, 2012.

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 September 30, 2012, 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
Energy procurement obligations of Pepco Energy Services (a)	$101	$—	$—	$—	$101
Guarantees associated with disposal of Conectiv Energy assets (b)	13	—	—	—	13
Guaranteed lease residual values (c)	2	4	6	4	16
Total	$116	$ 4	$ 6	$ 4	$130

(a) PHI has contractual commitments for performance and related payments of Pepco Energy Services to counterparties under routine energy sales and procurement obligations.

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

(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $52 million, $10 million of which is a guaranty by PHI, $14 million by Pepco, $17 million by DPL and $11 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 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 September 30, 2012, the remaining notional amount of Pepco Energy Services' energy savings guarantees on both completed projects and projects under construction totaled $449 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 September 30, 2012, 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 contracts, 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 September 30, 2012, 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 the three months ended September 30, 2012. There was no significant change in the type of contracts issued during the three and nine months ended September 30, 2012 as compared to the three and nine months ended September 30, 2011.

Dividends

On October 25, 2012, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable December 31, 2012, to stockholders of record on December 10, 2012.

(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.

	Commodity Derivatives	Treasury Lock	Pension and Other Postretirement Benefit Plans	Total
		(millions of dollars)		
Balance, December 31, 2011	$ (29)	$ (10)	$ (24)	$(63)
Change in period	8	—	—	8
Balance, March 31, 2012	(21)	(10)	(24)	(55)
Change in period	6	—	(2)	4
Balance, June 30, 2012	(15)	(10)	(26)	(51)
Change in period	4	—	—	4
Balance, September 30, 2012	$ (11)	$ (10)	$ (26)	$(47)

The income tax expense (benefit) for each component of Pepco Holdings' other comprehensive income is as follows:

	Commodity Derivatives	Treasury Lock	Pension and Other Postretirement Benefit Plans	Total
		(millions of dollars)		
For the three months ended September 30, 2012 (a)	$ 2	$ 1	$ 1	$ 4
For the three months ended September 30, 2011 (a)	7	1	(2)	6
For the nine months ended September 30, 2012 (b)	$ 13	$ 1	$ (2)	$ 12
For the nine months ended September 30, 2011 (b)	26	1	(3)	24

(a) Includes tax expense for losses reclassified to income during the three months ended September 30, 2012 and 2011 of $2 million and $7 million, respectively.

(b) Includes tax expense for losses reclassified to income during the nine months ended September 30, 2012 and 2011 of $13 million and $25 million, respectively.

(17) DISCONTINUED OPERATIONS

In April 2010, the Board of Directors approved a plan for the disposition of PHI's competitive wholesale power generation, marketing and supply business, which had been conducted through Conectiv Energy. On July 1, 2010, PHI completed the sale of Conectiv Energy's wholesale power generation business to Calpine. The disposition of all of Conectiv Energy's remaining assets and businesses, consisting of its load service supply contracts, energy hedging portfolio, certain tolling agreements and other assets not included in the Calpine sale has been completed.

Loss from discontinued operations, net of income taxes, for the three months ended September 30, 2012 and 2011, was zero. Income from discontinued operations, net of income taxes, for the nine months ended September 30, 2012 and 2011, was zero and $1 million, respectively.

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Operating Revenue	$ 582	$ 603	$ 1,503	$ 1,643
Operating Expenses				
Purchased energy	227	258	572	731
Other operation and maintenance	97	111	301	313
Depreciation and amortization	48	44	143	128
Other taxes	103	108	285	294
Total Operating Expenses	475	521	1,301	1,466
Operating Income	107	82	202	177
Other Income (Expenses)				
Interest expense	(27)	(24)	(76)	(70)
Other income	5	3	13	13
Total Other Expenses	(22)	(21)	(63)	(57)
Income Before Income Tax Expense	85	61	139	120
Income Tax Expense	35	23	38	32
Net Income	$ 50	$ 38	$ 101	$ 88

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5	$ 12
Accounts receivable, less allowance for uncollectible accounts of $15 million and $18 million, respectively	383	339
Inventories	71	50
Prepayments of income taxes	7	7
Income taxes receivable	31	31
Prepaid expenses and other	29	32
Total Current Assets	526	471
INVESTMENTS AND OTHER ASSETS		
Regulatory assets	455	299
Prepaid pension expense	358	289
Investment in trust	32	31
Income taxes receivable	103	24
Assets and accrued interest related to uncertain tax positions	7	—
Other	58	55
Total Investments and Other Assets	1,013	698
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	6,753	6,578
Accumulated depreciation	(2,704)	(2,704)
Net Property, Plant and Equipment	4,049	3,874
TOTAL ASSETS	$ 5,588	$ 5,043

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 134	$ 74
Accounts payable and accrued liabilities	231	209
Accounts payable due to associated companies	55	57
Capital lease obligations due within one year	12	8
Taxes accrued	63	63
Interest accrued	39	17
Other	110	110
Total Current Liabilities	644	538
DEFERRED CREDITS		
Regulatory liabilities	157	169
Deferred income taxes, net	1,257	1,039
Investment tax credits	4	5
Other postretirement benefit obligations	69	66
Liabilities and accrued interest related to uncertain tax positions	3	38
Other	65	68
Total Deferred Credits	1,555	1,385
LONG-TERM LIABILITIES		
Long-term debt	1,701	1,540
Capital lease obligations	70	78
Total Long-Term Liabilities	1,771	1,618
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	755	705
Retained earnings	863	797
Total Equity	1,618	1,502
TOTAL LIABILITIES AND EQUITY	$ 5,588	$ 5,043

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

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2012	2011
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 101	$ 88
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	143	128
Deferred income taxes	170	58
Changes in:		
Accounts receivable	(31)	5
Inventories	(21)	(10)
Prepaid expenses	5	6
Regulatory assets and liabilities, net	(67)	(16)
Accounts payable and accrued liabilities	29	(21)
Prepaid pension expense, excluding contributions	16	18
Pension contributions	(85)	(40)
Income tax-related prepayments, receivables and payables	(86)	92
Interest accrued	22	19
Other assets and liabilities	(6)	3
Net Cash From Operating Activities	190	330
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(449)	(361)
Department of Energy capital reimbursement awards received	23	24
Net other investing activities	(1)	(8)
Net Cash Used By Investing Activities	(427)	(345)
FINANCING ACTIVITIES		
Dividends paid to Parent	(35)	—
Capital contribution from Parent	50	—
Issuances of long-term debt	200	—
Reacquisitions of long-term debt	(38)	—
Issuances of short-term debt, net	60	—
Cost of issuances	(4)	—
Net other financing activities	(3)	(3)
Net Cash From (Used By) Financing Activities	230	(3)
Net Decrease in Cash and Cash Equivalents	(7)	(18)
Cash and Cash Equivalents at Beginning of Period	12	88
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 5	$ 70
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments to (from) PHI for federal income taxes)	$ (40)	$ (108)
Non-cash activities:		
Reclassification of property, plant and equipment to regulatory assets	53	—
Reclassification of asset removal costs regulatory liability to accumulated depreciation	19	—

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, 2011	100	$ —	$ 705	$ 797	$1,502
Net income	—	—	—	24	24
BALANCE, MARCH 31, 2012	100	—	705	821	1,526
Net income	—	—	—	27	27
Capital contribution from Parent	—	—	50	—	50
BALANCE, JUNE 30, 2012	100	—	755	848	1,603
Net income	—	—	—	50	50
Dividends on common stock	—	—	—	(35)	(35)
BALANCE, SEPTEMBER 30, 2012	100	$ —	$ 755	$ 863	$1,618

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

NOTES TO FINANCIAL STATEMENTS

POTOMAC ELECTRIC POWER COMPANY

(1) ORGANIZATION

Potomac Electric Power Company (Pepco) is engaged in the transmission and distribution of electricity in the District of Columbia and major portions of Prince George's County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territories who do not elect to purchase electricity from a competitive energy 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, 2011, as amended to include the executive compensation and other information required by Part III of Form 10-K (which information originally had been omitted as permitted by that form). In the opinion of Pepco's management, the financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly Pepco's financial condition as of September 30, 2012, in accordance with GAAP. The year-end December 31, 2011 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 nine months ended September 30, 2012 may not be indicative of results that will be realized for the full year ending December 31, 2012.

Use of Estimates

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

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset impairment evaluations, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of 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.

Storm Restoration Costs

On June 29, 2012, the respective service territories of Pepco were affected by a rapidly moving thunderstorm with hurricane-force winds, known as a "derecho," which resulted in widespread customer outages in each of the service territories. The derecho caused extensive damage to Pepco's electric transmission and distribution systems. Storm restoration activity commenced immediately following the storm and continued into July 2012, with the majority of the incremental storm restoration costs occurring in the third quarter of 2012.

Total incremental storm restoration costs incurred by Pepco through September 30, 2012 were $42 million, with $25 million incurred for repair work and $17 million incurred as capital expenditures. Costs incurred for repair work of $21 million were deferred as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland, and $4 million was charged to Other operation and maintenance expense. As of September 30, 2012, total incremental storm restoration costs include $15 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from these estimates. Pepco will be pursuing recovery of the incremental storm restoration costs during the next cycle of distribution base rate cases.

General and Auto Liability

During the second quarter of 2011, Pepco reduced its self-insurance reserves for general and auto liability claims by approximately $1 million, based on obtaining an actuarial estimate of the unpaid losses attributed to general and auto liability claims for Pepco at June 30, 2011. A similar evaluation was performed in the third quarter of 2012 and no material adjustments were made to these reserves.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco's gross revenues were $100 million for each of the three months ended September 30, 2012 and 2011, and $268 million and $271 million for the nine months ended September 30, 2012 and 2011, 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

During the first quarter of 2011, Pepco recorded an adjustment to correct certain income tax errors related to prior periods associated with interest on uncertain tax positions. The adjustment resulted in an increase in Income tax expense of $1 million for the nine months ended September 30, 2011.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Fair Value Measurements and Disclosures (Accounting Standards Codification (ASC) 820)

The Financial Accounting Standards Board (FASB) issued new guidance on fair value measurement and disclosures that was effective beginning with Pepco's March 31, 2012 financial statements. The new measurement guidance did not have a material impact on Pepco's financial statements and the new disclosure requirements are in Note (10), "Fair Value Disclosures," of Pepco's financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

None.

(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 Pepco electric service in Maryland and the District of Columbia. The Maryland Public Service Commission (MPSC) later modified the BSA in Maryland so that revenues lost as a result of major storm outages are not collected through the BSA if electric service is not restored to the pre-major storm levels within 24 hours of the start of a major storm. 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. For further information on the BSA in Maryland, see "Maryland—BSA Proceeding" below.

In an effort to reduce the shortfall in revenues due to the delay in time or lag between when costs are incurred and when they are reflected in rates (regulatory lag), Pepco proposed, in each of its jurisdictions, (i) a reliability investment recovery mechanism (RIM) to recover reliability-related capital expenditures incurred between base rate cases, and (ii) the use of fully forecasted test years in future rate cases (which are comprised of forward-looking costs in lieu of historical test years, and if approved, would be more reflective of current costs and would mitigate the effects of regulatory lag). The status of these proposals is discussed below in connection with the discussions of Pepco's electric distribution base rate proceedings.

District of Columbia

On July 8, 2011, Pepco filed an application with the District of Columbia Public Service Commission (DCPSC) to increase its electric distribution base rates by approximately $42 million annually, based on a requested return on equity (ROE) of 10.75%, of which approximately $9 million was sought so that Pepco could recover its costs associated with the advanced metering infrastructure (AMI) project. The filing included a request for DCPSC approval of a RIM and the use of fully forecasted test years in future Pepco rate cases. On September 26, 2012, the DCPSC issued its decision approving a rate increase of $24 million, based on an ROE of 9.5%, of which approximately $9 million allows Pepco to recover costs associated with the AMI project. The DCPSC denied Pepco's request for approval of a RIM, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases. In addition, the DCPSC approved an adjustment by Pepco to normalize operation and maintenance expenses associated with storm restoration efforts to its three-year average, but added approximately $2 million of costs associated with Hurricane Irene from August 2011 in the calculation of the three-year average storm costs. On October 31, 2012, the District of Columbia Office of the People's Counsel filed a motion with the DCPSC for reconsideration of a portion of the order, objecting to (i) the percentage of the rate increase allocated to residential customers, and (ii) the decision not to adjust Pepco's base rates downward because of the quality and reliability of Pepco's electric distribution service. Pepco also filed a motion for reconsideration and clarification on that date (i) objecting to provisions requiring Pepco to perform studies and report certain information three months in advance of its next base rate case filing, and (ii) requesting clarification concerning the timing of certain reporting requirements. The filing of these motions does not stay the order or delay the rate increase from going into effect.

Maryland

<u>Electric Distribution Base Rates</u>

On December 16, 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%. The filing included a request for MPSC approval of a RIM and the use of fully forecasted test years in future Pepco rate cases. On July 20, 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. The MPSC also directed Pepco to reduce the amount of the rate increase by approximately $1.6 million, the annual costs of certain energy advisory programs, resulting in a final rate increase of approximately $16.5 million. Pepco would be required to seek recovery of these annual costs through the EmPower Maryland Program. The MPSC reduced Pepco's depreciation rates, which is expected to lower annual depreciation and amortization expenses by an estimated $27.3 million. The order did not approve Pepco's request to implement a RIM and did not endorse the use by Pepco of fully forecasted test years in future rate cases. The order authorizes Pepco to recover in rates over a five-year period $18.5 million of incremental storm restoration costs associated with major weather events in 2011, including $9.7 million of the $9.9 million of incremental storm restoration costs associated with Hurricane Irene that had been deferred previously as a regulatory asset by Pepco and $8.8 million of incremental storm restoration costs incurred by Pepco associated with a severe winter storm in the first quarter of 2011 that had been expensed previously through other operation and maintenance expense in 2011. The incremental storm restoration costs of $8.8 million were reversed and deferred as a regulatory asset in the third quarter of 2012. The order also authorizes Pepco to recover the actual cost of AMI meters installed during the 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 proven to be cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. Pepco has determined not to appeal the MPSC order. The Maryland Office of People's Counsel has sought rehearing on the portion of the order allowing Pepco to recover the costs of installed AMI meters; that motion remains pending.

BSA Proceeding

As in effect for electric utilities in Maryland prior to October 26, 2012, including Pepco, a utility was not permitted to collect through the BSA distribution revenues lost as a result of major storm outages, beginning 24 hours after the commencement of a major storm, if electric service is not restored to the pre-major storm levels within 24 hours of the start of the storm. On October 26, 2012, the MPSC issued an order that no longer permits Pepco, among other utilities, to collect a BSA surcharge for revenues lost during the first 24 hours of a major storm.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether the electric distribution companies (EDCs) in Maryland 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 certain Maryland EDCs, including Pepco, 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 (SOS refers to the supply of electricity to retail customers who do not elect to purchase electricity from a competitive supplier but instead purchase such electricity from Pepco at regulated rates). 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 acknowledges certain of the EDCs' concerns about the requirements of the contract and directs them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specifies that the EDCs entering into the contract will recover the associated costs, in amounts proportional to their relative SOS loads, through surcharges on their respective SOS customers.

Until the final form of the contract with the winning bidder and associated cost recovery are approved, Pepco cannot predict (i) the extent of the negative effect that the order and, once finalized, the contract for new generation, may have on Pepco's balance sheets, as well as its 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 order on the financial condition, results of operations and cash flows of Pepco.

On April 27, 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the Northern 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. On May 4, 2012, Pepco, its affiliate Delmarva Power & Light Company (DPL), and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These appeals have been consolidated in the Circuit Court for Baltimore City and are set for hearing on January 24, 2013.

Maryland Governor's Grid Resiliency 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 the Task Force 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 is currently evaluating the report and its recommendations to determine what effect, if any, they may have on proposals to be made in its future electric distribution base rate cases in Maryland. The form and substance of any such proposals will also depend, in part, on how the MPSC responds to the report and the governor's request.

Termination of the MAPP Project

In 2007, PJM Interconnection, LLC (PJM) (the regional transmission organization that is responsible for planning the transmission grid and coordinating the movement of wholesale electricity within a region consisting of all or parts of 13 states and the District of Columbia) directed PHI to construct a high-voltage interstate transmission line to address the reliability needs of the region's transmission system. In its most recent configuration, the transmission line, which PHI referred to as the Mid-Atlantic Power Pathway (MAPP), would have covered 152 miles, originating at the Possum Point substation in northern Virginia, traversing under the Chesapeake Bay and ending at the Indian River substation in Delaware.

On August 24, 2012, the board of PJM notified PHI, on behalf of its subsidiaries Pepco and DPL, that the MAPP project has been terminated and removed from PJM's regional transmission expansion plan.

As a result of PJM's decision, on October 2, 2012, Pepco filed with the MPSC a notice withdrawing its pending application related to the MAPP project. Pepco had included in its five-year projected capital expenditures $138 million of MAPP-related expenditures for the period from 2012 to 2016. Pepco has updated its five-year projected capital expenditures to remove MAPP-related expenditures to reflect the PJM decision.

As of September 30, 2012, Pepco's total capital expenditures for the MAPP project were approximately $64 million. Under the terms of the Federal Energy Regulatory Commission (FERC) order approving an incentive rate for the MAPP project, FERC authorized the recovery of abandoned costs prudently incurred in connection with the MAPP project. Consistent with this order, Pepco intends to seek recovery of abandoned MAPP capital expenditures through a filing expected to be submitted to the FERC in the fourth quarter of 2012. The FERC filing is expected to address, among other things, the period over which the abandoned costs are to be recovered and the rate of return on these costs during the recovery period. Under an order issued by the FERC in 2008, Pepco has been allowed to include its MAPP capital expenditures in its rate base, earning an incentive rate of return of 12.8% during the construction period.

As of September 30, 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, and reclassified the remaining $53 million of capital expenditures to a regulatory asset. 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 the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

Pepco accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and 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 September 30, 2012 and 2011, before intercompany allocations from the PHI Service Company, were $28 million and $24 million, respectively. Pepco's allocated share was $10 million and $15 million, respectively, for the three months ended September 30, 2012 and 2011. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2012 and 2011, before intercompany allocations from the PHI Service Company, were $84 million and $70 million, respectively. Pepco's allocated share was $30 million and $32 million, respectively, for the nine months ended September 30, 2012 and 2011.

In the first quarter of 2012, Pepco made a discretionary tax-deductible contribution to the PHI Retirement Plan of $85 million. In the first quarter of 2011, Pepco made a discretionary tax-deductible contribution to the PHI Retirement Plan in the amount of $40 million.

(8) DEBT

Credit Facility

PHI, Pepco, DPL and Atlantic City Electric Company (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 among other changes, extended the expiration date of the facility to August 1, 2016. On August 2, 2012, the amended and restated credit agreement 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.

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 initial credit sublimit for PHI is $750 million 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 September 30, 2012.

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.

At September 30, 2012 and December 31, 2011, 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 $563 million and $711 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 September 30, 2012, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

Pepco had $134 million of commercial paper outstanding at September 30, 2012. The weighted average interest rate for commercial paper issued by Pepco during the nine months ended September 30, 2012 was 0.42% and the weighted average maturity of all commercial paper issued by Pepco during the nine months ended September 30, 2012 was four days.

(9) INCOME TAXES

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 30	35.0%	$ 21	35.0%	$ 49	35.0%	$ 42	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	5	5.9	4	6.1	8	5.8	6	5.3
Asset removal costs	(1)	(1.2)	(2)	(3.0)	(8)	(5.8)	(4)	(3.7)
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	1	1.3	(11)	(7.9)	(4)	(2.7)
Permanent differences related to deferred compensation funding	—	—	—	(0.3)	(1)	(0.7)	(2)	(1.4)
State tax benefit related to prior years' asset dispositions	—	—	—	—	—	—	(4)	(3.5)
Tax credits	—	—	—	—	(1)	(0.7)	—	—
Other, net	1	1.5	(1)	(1.4)	2	1.6	(2)	(2.3)
Income tax expense	$ 35	41.2%	$ 23	37.7%	$ 38	27.3%	$ 32	26.7%

Three Months Ended September 30, 2012 and 2011

Pepco's effective income tax rates for the three months ended September 30, 2012 and 2011 were 41.2% and 37.7%, respectively. The increase in the effective income tax rate primarily resulted from a decrease in asset removal costs as a result of fewer asset retirements in the third quarter of 2012 and a decrease in benefits associated with changes in estimates and interest related to uncertain and effectively settled tax positions.

Nine Months Ended September 30, 2012 and 2011

Pepco's effective income tax rates for the nine months ended September 30, 2012 and 2011 were 27.3% and 26.7%, respectively. The effective income tax rates primarily reflect tax benefits recorded in each period related to asset removal costs and changes in estimates and interest related to uncertain and effectively settled tax positions and a tax benefit recorded in 2011 for state tax refunds associated with prior years' asset dispositions.

In the first quarter of 2012, Pepco recorded income tax benefits of $10 million 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.

In the second quarter of 2011, PHI reached a settlement with the IRS with respect to interest due on its federal tax liabilities related to the tax years 1996 through 2002. In connection with this agreement, PHI reallocated certain amounts that have been on deposit with the IRS since 2006 among liabilities in the settlement years and subsequent years. Primarily related to the settlement and reallocations, Pepco recorded an additional tax benefit in the amount of $5 million (after-tax) in the second quarter of 2011.

In the second quarter of 2011, Pepco received refunds of approximately $5 million and recorded tax benefits of approximately $4 million (after-tax) related to the filing of amended state tax returns. These amended returns reduced state taxable income due to an increase in tax basis on certain prior years' asset dispositions.

(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 September 30, 2012 and December 31, 2011. 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 September 30, 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				
Executive deferred compensation plan assets				
Money market funds	$ 17	$ 17	$ —	$ —
Life insurance contracts	53	—	36	17
	$ 70	$ 17	$ 36	$ 17
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 nine months ended September 30, 2012.

	Fair Value Measurements at December 31, 2011			
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	$ 12	$ 12	$ —	$ —
Life insurance contracts	57	—	40	17
	$ 69	$ 12	$ 40	$ 17
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 10	$ —	$ 10	$ —
	$ 10	$ —	$ 10	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2011.

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 September 30, 2012. 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 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 Pepco for reasonableness.

Reconciliations of the beginning and ending balances of Pepco's fair value measurements using significant unobservable inputs (level 3) for the nine months ended September 30, 2012 and 2011 are shown below:

	Life Insurance Contracts Nine Months Ended September 30,	
	2012	**2011**
	(millions of dollars)	
Beginning balance as of January 1	$ 17	$ 18
Total gains (losses) (realized and unrealized):		
Included in income	3	5
Included in accumulated other comprehensive loss	—	—
Purchases	—	—
Issuances	(3)	(3)
Settlements	—	(4)
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ 17	$ 16

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:

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(millions of dollars)	
Total gains included in income for the period	$ 3	$ 5
Change in unrealized gains relating to assets still held at reporting date	$ 3	$ 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 September 30, 2012 are shown in the table 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 in active markets, but not 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 September 30, 2012			
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)	$2,195	$ 712	$ 1,483	$ —
	$2,195	$ 712	$ 1,483	$ —

(a) The carrying amount for Long-term debt is $1,701 million as of September 30, 2012.

The estimated fair value of Pepco's debt instruments at December 31, 2011 is shown below:

	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value
	(millions of dollars)	
Long-term debt	$ 1,540	$1,943

The carrying amount of all other financial instruments in the accompanying 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 Pepco's customers, 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 described below of Pepco at September 30, 2012 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
		(millions of dollars)	
Beginning balance as of January 1	$ 14	$ 4	$ 18
Accruals	—	—	—
Payments	—	(1)	(1)
Ending balance as of September 30	14	3	17
Less amounts in Other current liabilities	1	—	1
Amounts in Other deferred credits	$ 13	$ 3	$ 16

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, 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. Although Pepco cannot at this time 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 and therefore, costs incurred to resolve this matter are not expected to be material.

Benning Road Site

In September 2010, PHI received a letter from EPA stating that EPA and the District of Columbia Department of the Environment (DDOE) have identified 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 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. The court order entering the consent decree requires the parties to submit a written status report to the court on May 24, 2013 regarding the implementation of the requirements of the consent decree and any related plans for remediation. In addition, if the RI/FS has not been completed by May 24, 2013, the status report must provide an explanation and a showing of good cause for why the work has not been completed.

Pepco and Pepco Energy Services submitted a proposed RI/FS work plan in July 2012, and anticipate that the work plan will be approved by DDOE during the fourth quarter of 2012, following which the RI/FS field work will commence.

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.

The release falls within the regulatory jurisdiction of multiple federal and state agencies. 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. Initial discussions with DDOE indicate 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. Based on the 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.

In March 2011, the Virginia Department of Environmental Quality (VADEQ) requested documentation regarding the release and the preparation of an emergency response report, which Pepco submitted to the agency in April 2011. In March 2011, Pepco received a notice of violation from VADEQ and in December 2011, entered into a consent decree with VADEQ, pursuant to which Pepco paid a civil penalty of approximately $40,000. The U.S. Coast Guard assessed a $5,000 penalty against Pepco for the release of oil into the waters of the United States, which Pepco has paid.

During March 2011, EPA conducted an inspection of the Potomac River substation to review compliance with federal regulations regarding Spill Prevention, Control, and Countermeasure (SPCC) plans for facilities using oil-containing equipment in proximity to surface waters. EPA identified several potential violations of the SPCC regulations relating to SPCC plan content, recordkeeping, and secondary containment. As a result of the oil release, Pepco submitted a revised SPCC plan to EPA in August 2011 and 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 and, after receiving such approval, will submit a further revised SPCC plan to EPA. In the meantime, Pepco is continuing to use the aboveground holding tank to manage storm water from the secondary containment system. On April 19, 2012, EPA advised Pepco that it is not seeking civil penalties at this time for alleged non-compliance with SPCC regulations.

The amounts accrued for these matters are included in the table above in the column entitled "Transmission and Distribution."

District of Columbia Tax Legislation

On September 14, 2012, the District of Columbia Office of Tax and Revenue adopted regulations to implement the mandatory unitary combined reporting method for tax years beginning in 2011. Pepco has analyzed these regulations and determined that the regulations did not impact Pepco's results of operations for the three and nine months ended September 30, 2012.

(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 September 30, 2012 and 2011 were approximately $55 million and $47 million, respectively. PHI Service Company costs directly charged or allocated to Pepco for the nine months ended September 30, 2012 and 2011 were approximately $158 million and $133 million, respectively.

Pepco Energy Services performs utility maintenance services, including services that are treated as capital costs, for Pepco. Amounts charged to Pepco by Pepco Energy Services for the three months ended September 30, 2012 and 2011 were approximately $4 million and $6 million, respectively. Amounts charged to Pepco by these companies for the nine months ended September 30, 2012 and 2011 were approximately $14 million each.

As of September 30, 2012 and December 31, 2011, Pepco had the following balances on its balance sheets due to related parties:

	September 30, 2012	December 31, 2011
	(millions of dollars)	
(Payable to) Receivable from Related Party (current) (a)		
PHI Parent Company	$ —	$ 15
PHI Service Company	(30)	(32)
Pepco Energy Services (b)	(25)	(40)
Total	$ (55)	$ (57)

(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.

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Operating Revenue				
Electric	$ 314	$ 298	$ 808	$ 841
Natural gas	26	28	124	169
Total Operating Revenue	340	326	932	1,010
Operating Expenses				
Purchased energy	178	180	443	507
Gas purchased	15	18	77	114
Other operation and maintenance	65	69	192	181
Depreciation and amortization	29	22	78	66
Other taxes	10	8	26	28
Total Operating Expenses	297	297	816	896
Operating Income	43	29	116	114
Other Income (Expenses)				
Interest expense	(12)	(11)	(34)	(33)
Other income	2	3	8	7
Total Other Expenses	(10)	(8)	(26)	(26)
Income Before Income Tax Expense	33	21	90	88
Income Tax Expense	11	10	34	32
Net Income	$ 22	$ 11	$ 56	$ 56

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 41	$ 5
Accounts receivable, less allowance for uncollectible accounts of $10 million and $12 million, respectively	192	186
Inventories	55	44
Prepayments of income taxes	10	14
Income taxes receivable	10	11
Prepaid expenses and other	20	17
Total Current Assets	328	277
INVESTMENTS AND OTHER ASSETS		
Goodwill	8	8
Regulatory assets	271	227
Prepaid pension expense	236	162
Assets and accrued interest related to uncertain tax positions	20	—
Other	12	23
Total Investments and Other Assets	547	420
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	3,330	3,188
Accumulated depreciation	(988)	(926)
Net Property, Plant and Equipment	2,342	2,262
TOTAL ASSETS	$ 3,217	$ 2,959

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 105	$ 152
Current portion of long-term debt	—	66
Accounts payable and accrued liabilities	94	92
Accounts payable due to associated companies	23	21
Taxes accrued	7	11
Interest accrued	14	6
Derivative liabilities	7	12
Other	64	59
Total Current Liabilities	314	419
DEFERRED CREDITS		
Regulatory liabilities	262	297
Deferred income taxes, net	683	615
Investment tax credits	6	6
Other postretirement benefit obligations	26	22
Liabilities and accrued interest related to uncertain tax positions	—	9
Derivative liabilities	—	3
Other	41	37
Total Deferred Credits	1,018	989
LONG-TERM LIABILITIES		
Long-term debt	917	699
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	347
Retained earnings	561	505
Total Equity	968	852
TOTAL LIABILITIES AND EQUITY	$ 3,217	$ 2,959

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

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

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 56	$ 56
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	78	66
Deferred income taxes	44	81
Changes in:		
Accounts receivable	(6)	39
Inventories	(11)	(6)
Regulatory assets and liabilities, net	(16)	(34)
Accounts payable and accrued liabilities	2	(31)
Pension contributions	(85)	(40)
Income tax-related prepayments, receivables and payables	11	(23)
Other assets and liabilities	15	22
Net Cash From Operating Activities	88	130
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(219)	(146)
Net other investing activities	(4)	—
Net Cash Used By Investing Activities	(223)	(146)
FINANCING ACTIVITIES		
Dividends paid to Parent	—	(50)
Capital contribution from Parent	60	—
Issuances of long-term debt	250	35
Reacquisitions of long-term debt	(97)	(35)
Repayments of short-term debt, net	(47)	—
Cost of issuances	(3)	—
Net other financing activities	8	9
Net Cash From (Used by) Financing Activities	171	(41)
Net Increase (Decrease) in Cash and Cash Equivalents	36	(57)
Cash and Cash Equivalents at Beginning of Period	5	69
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 41	$ 12
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments (from) to PHI for federal income taxes)	$ (24)	$ (24)
Non-cash activities:		
Reclassification of property, plant and equipment to regulatory assets	37	—
Reclassification of asset removal costs regulatory liability to accumulated depreciation	42	—

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, 2011	1,000	$ —	$ 347	$ 505	$852
Net income	—	—	—	21	21
BALANCE, MARCH 31, 2012	1,000	—	347	526	873
Net income	—	—	—	13	13
BALANCE, JUNE 30, 2012	1,000	—	347	539	886
Net income	—	—	—	22	22
Capital contribution from Parent	—	—	60	—	60
BALANCE, SEPTEMBER 30, 2012	1,000	$ —	$ 407	$ 561	$968

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. DPL 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 energy 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, 2011, as amended to include the executive compensation and other information required by Part III of Form 10-K (which information originally had been omitted as permitted by that form). In the opinion of DPL's management, the financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly DPL's financial condition as of September 30, 2012, in accordance with GAAP. The year-end December 31, 2011 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 nine months ended September 30, 2012 may not be indicative of DPL's results that will be realized for the full year ending December 31, 2012.

Use of Estimates

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

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset and goodwill impairment evaluations, fair value calculations for derivative instruments, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of 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.

Storm Restoration Costs

On June 29, 2012, the respective service territories of DPL were affected by a rapidly moving thunderstorm with hurricane-force winds, known as a "derecho," which resulted in widespread customer outages in each of the service territories. The derecho caused extensive damage to DPL's electric transmission and distribution systems. Storm restoration activity commenced immediately following the storm and continued into July 2012, with the majority of the incremental storm restoration costs occurring in the third quarter of 2012.

Total incremental storm restoration costs incurred by DPL through September 30, 2012 were $3 million, with $2 million incurred for repair work and $1 million incurred as capital expenditures. Costs incurred for repair work of $1 million were deferred as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland, and $1 million was charged to Other operation and maintenance expense. DPL will be pursuing recovery of the incremental storm restoration costs during the next cycle of distribution base rate cases.

General and Auto Liability

For the three and nine months ended September 30, 2012, DPL reduced its self-insurance reserves for general and auto liability claims by approximately $1 million based on obtaining an actuarial estimate of the unpaid losses attributed to general and auto liability claims for DPL at September 30, 2012. During the second quarter of 2011, DPL reduced its self-insurance reserves for general and auto liability claims by approximately $2 million, based on obtaining an actuarial estimate of the unpaid losses attributed to general and auto liability claims for DPL at June 30, 2011.

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 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.

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 September 30, 2012, DPL has entered into 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 are 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 PPAs. DPL 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, in each case at the rates primarily fixed by the PPA. DPL's purchases under the three wind PPAs totaled $4 million and $3 million for the three months ended September 30, 2012 and 2011, respectively, and $20 million and $12 million for the nine months ended September 30, 2012 and 2011, 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 $1 million and $2 million for the three and nine months ended September 30, 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 MW to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL would be an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour of energy produced by the fuel cell facilities 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. In June 2012, a 3 MW fuel cell generation facility was placed into service under the tariff. DPL billed less than $1 million to distribution customers during the three and nine months ended September 30, 2012. A 27 MW fuel cell generation facility is expected to be placed into service in 5 MW increments beginning in January 2013. DPL is accounting for this arrangement as an agency transaction.

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 nine months ended September 30, 2012.

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 September 30, 2012 and 2011, and $12 million and $14 million for the nine months ended September 30, 2012 and 2011, 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:

Natural Gas 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 nine months ended September 30, 2012.

Default Electricity Supply Revenue and Cost Adjustments

During 2011, DPL recorded adjustments to correct certain errors associated with the accounting for Default Electricity Supply revenue and costs. These adjustments primarily arose from the under-recognition of allowed returns on the cost of working capital and resulted in a pre-tax decrease in Other operation and maintenance expense of $1 million and $9 million for the three and nine months ended September 30, 2011, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Fair Value Measurements and Disclosures (ASC 820)

The FASB issued new guidance on fair value measurement and disclosures that was effective beginning with DPL's March 31, 2012 financial statements. The new measurement guidance did not have a material impact on DPL's financial statements and the new disclosure requirements are in Note (12), "Fair Value Disclosures," of DPL's financial statements.

Goodwill (ASC 350)

The FASB issued new guidance that changes the annual and interim assessments of goodwill for impairment. The new guidance modifies the required annual impairment test by giving entities the option to perform a qualitative assessment of whether it is more likely than not that goodwill is impaired before performing a quantitative assessment. The new guidance also amends the events and circumstances that entities should assess to determine whether an interim quantitative impairment test is necessary. As of January 1, 2012, DPL has adopted the new guidance and concluded it did not have a material impact on its financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosures will include information about the gross exposures 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. The new disclosures are effective beginning with DPL's March 31, 2013 financial statements. DPL is 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 nine months ended September 30, 2012. 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, 2011 indicated that goodwill was not impaired. For the nine months ended September 30, 2012, 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, 2012.

(7) REGULATORY MATTERS

Rate Proceedings

Over the last several years, DPL 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. The Maryland Public Service Commission (MPSC) later modified the BSA in Maryland so that revenues lost as a result of major storm outages are not collected through the BSA if electric service is not restored to the pre-major storm levels within 24 hours of the start of a major storm. For further information on the BSA in Maryland, see "Maryland – BSA Proceeding" below.
- A modified fixed variable rate design (MFVRD) has been approved in concept for DPL electric and natural gas service in Delaware, but the implementation has been deferred by the DPSC pending the development of an implementation plan and a customer education plan, as well as the resolution of various matters relating to development of a statewide energy efficiency plan and attendant legislation.

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) 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.

In an effort to reduce the shortfall in revenues due to the delay in time or lag between when costs are incurred and when they are reflected in rates (regulatory lag), DPL proposed, in each of its jurisdictions, (i) a reliability investment recovery mechanism (RIM) to recover reliability-related capital expenditures incurred between base rate cases, and (ii) the use of fully forecasted test years in future rate cases (which are comprised of forward-looking costs in lieu of historical test years, and if approved, would be more reflective of current costs and would mitigate the effects of regulatory lag). The status of these proposals is discussed below in connection with the discussions of DPL's electric distribution base rate proceedings.

Delaware

<u>Gas Cost Rates</u>

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 2011, DPL made its 2011 GCR filing. The filing includes the second year of the effect of a two-year amortization of under-recovered gas costs proposed by DPL in its 2010 GCR filing (the settlement approved by the DPSC in its 2010 GCR case included only the first year of the proposed two-year amortization). The rates proposed in the 2011 GCR would result in a GCR decrease of approximately 5.6%. On August 21, 2012, the DPSC issued a final order approving the rates as filed.

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.

<u>Electric Distribution Base Rates</u>

On December 2, 2011, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $31.8 million, based on a requested return on equity (ROE) of 10.75%, and requested approval of implementation of the MFVRD. The filing included a request for DPSC approval of a RIM and the use of fully forecasted test years in future DPL rate cases. On January 10, 2012, the DPSC entered an order suspending the full increase and allowing a temporary rate increase of $2.5 million to go into effect on January 31, 2012, subject to refund and pending final DPSC approval. On July 3, 2012, in accordance with an agreement with DPSC staff, DPL placed an additional $22.3 million of the requested rate increase into effect, also subject to refund and pending final DPSC order. On August 17, 2012, DPL and the other parties to the proceeding entered into a proposed settlement that provides for an annual rate increase of $22 million, based on an ROE of 9.75%. The settlement agreement also permits DPL to collect from its standard offer service (SOS) customers (retail customers who do not elect to purchase electricity from a competitive supplier but instead purchase such electricity from DPL at regulated rates) approximately $3.4 million related to various state and local taxes that were assessed upon DPL's SOS customers, but actually paid by DPL rather than by the SOS customers upon whom they were assessed. These taxes would be collected over a three-year period. In addition, the settlement agreement allows for the phase-in of the recovery of costs associated with DPL's advanced metering infrastructure (AMI) project. The settlement agreement does not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it does provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag. The settlement agreement is subject to approval by the DPSC. Once approved by the DPSC, DPL will refund the billed amounts that exceeded the increase approved by the DPSC. DPL expects the DPSC to issue a decision on the settlement agreement in the fourth quarter of 2012.

Maryland

Electric Distribution Base Rates

On December 9, 2011, DPL submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $25.2 million (subsequently reduced by DPL to $23.5 million), based on a requested ROE of 10.75%. The filing included a request for MPSC approval of a RIM and the use of fully forecasted test years in future DPL rate cases. On July 20, 2012, the MPSC issued an order approving an annual rate increase of approximately $11.3 million, based on an ROE of 9.81%. The MPSC reduced DPL's depreciation rates, which is expected to lower annual depreciation and amortization expenses by an estimated $4.1 million. The order did not approve DPL's request to implement a RIM and did not endorse the use by DPL of fully forecasted test years in future rate cases. The order also authorizes DPL to recover in rates over a five-year period $4.3 million of the $4.6 million of incremental storm restoration costs associated with Hurricane Irene that had been deferred previously as a regulatory asset by DPL. The new revenue rates and lower depreciation rates were effective on July 20, 2012. DPL has determined not to appeal the MPSC order.

BSA Proceeding

As in effect for electric utilities in Maryland prior to October 26, 2012, including DPL, a utility was not permitted to collect through the BSA distribution revenues lost as a result of major storm outages, beginning 24 hours after the commencement of a major storm, if electric service is not restored to the pre-major storm levels within 24 hours of the start of the storm. On October 26, 2012, the MPSC issued an order that no longer permits DPL, among other Maryland utilities, to collect a BSA surcharge for revenues lost during the first 24 hours of a major storm.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether the EDCs in Maryland 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 certain Maryland electric distribution companies (EDCs), including DPL, 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 acknowledges certain of the EDCs' concerns about the requirements of the contract and directs them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specifies that the EDCs entering into the contract will recover the associated costs, in amounts proportional to their relative SOS loads, through surcharges on their respective SOS customers.

Until the final form of the contract with the winning bidder and associated cost recovery are approved, DPL cannot predict (i) the extent of the negative effect that the order and, once finalized, the contract for new generation, may have on DPL's balance sheets, as well as its credit metrics, as calculated by independent rating agencies that evaluate and rate DPL and its debt issuances, (ii) the effect on DPL's ability to recover its associated costs of the 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 order on the financial condition, results of operations and cash flows of DPL.

On April 27, 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 Northern 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. On May 4, 2012, DPL and its affiliate Potomac Electric Power Company (Pepco), and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These appeals have been consolidated in the Circuit Court for Baltimore City and are set for hearing on January 24, 2013.

Maryland Governor's Grid Resiliency 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 the Task Force 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 is currently evaluating the report and its recommendations to determine what effect, if any, they may have on proposals to be made in its future electric distribution base rate cases in Maryland. The form and substance of any such proposals will also depend, in part, on how the MPSC responds to the report and the governor's request.

Termination of the MAPP Project

In 2007, PJM (the regional transmission organization that is responsible for planning the transmission grid and coordinating the movement of wholesale electricity within a region consisting of all or parts of 13 states and the District of Columbia) directed PHI to construct a high-voltage interstate transmission line to address the reliability needs of the region's transmission system. In its most recent configuration, the transmission line, which PHI referred to as the Mid-Atlantic Power Pathway (MAPP), would have covered 152 miles, originating at the Possum Point substation in northern Virginia, traversing under the Chesapeake Bay and ending at the Indian River substation in Delaware.

On August 24, 2012, the board of PJM notified PHI, on behalf of its subsidiaries Pepco and DPL, that the MAPP project has been terminated and removed from PJM's regional transmission expansion plan.

As a result of PJM's decision, on October 2, 2012, DPL filed with the MPSC a notice withdrawing its pending application related to the MAPP project. DPL had included in its five-year projected capital expenditures $67 million of MAPP-related expenditures for the period from 2012 to 2016. DPL has updated its five-year projected capital expenditures to remove MAPP-related expenditures to reflect the PJM decision.

As of September 30, 2012, DPL's total capital expenditures for the MAPP project were approximately $37 million. Under the terms of the Federal Energy Regulatory Commission (FERC) order approving an incentive rate for the MAPP project, FERC authorized the recovery of abandoned costs prudently incurred in connection with the MAPP project. Consistent with this order, DPL intends to seek recovery of abandoned MAPP capital expenditures through a filing expected to be submitted to the FERC in the fourth quarter of 2012. The FERC filing is expected to address, among other things, the period over which the abandoned costs are to be recovered and the rate of return on these costs during the recovery period. Under an order issued by the FERC in 2008, DPL has been allowed to include its MAPP capital expenditures in its rate base, earning an incentive rate of return of 12.8% during the construction period.

As of September 30, 2012, DPL had reclassified all $37 million of capital expenditures with respect to the MAPP project to a regulatory asset. The regulatory asset includes the costs of land, land rights and supplies, engineering and design, environmental services, and project management and administration. DPL intends to reduce the regulatory asset by any amounts recovered from the sale or alternative use of the land and land rights.

(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 September 30, 2012 and 2011, before intercompany allocations from the PHI Service Company, were $28 million and $24 million, respectively. DPL's allocated share was $6 million each for the three months ended September 30, 2012 and 2011. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2012 and 2011, before intercompany allocations from the PHI Service Company, were $84 million and $70 million, respectively. DPL's allocated share was $18 million each for the nine months ended September 30, 2012 and 2011.

In the first quarter of 2012, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan of $85 million. In the first quarter of 2011, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan in the amount of $40 million.

(9) DEBT

Credit Facility

PHI, Pepco, DPL and Atlantic City Electric Company (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 among other changes, extended the expiration date of the facility to August 1, 2016. On August 2, 2012, the amended and restated credit agreement 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.

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 initial credit sublimit for PHI is $750 million 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 September 30, 2012.

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.

At September 30, 2012 and December 31, 2011, 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 $563 million and $711 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 September 30, 2012, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had no commercial paper outstanding at September 30, 2012. The weighted average interest rate for commercial paper issued by DPL during the nine months ended September 30, 2012 was 0.43% and the weighted average maturity of all commercial paper issued by DPL during the nine months ended September 30, 2012 was four days.

Other Financing Activities

On August 6, 2012, DPL redeemed, prior to maturity, $31 million of its 5.20% tax-exempt pollution control refunding revenue bonds due 2019, issued by the Delaware Economic Development Authority for DPL's benefit. Contemporaneously with this redemption, DPL redeemed $31 million of its outstanding 5.20% first mortgage bonds due 2019 that secured the obligations under the pollution control bonds.

(10) INCOME TAXES

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 12	35.0%	$ 7	35.0%	$ 32	35.0%	$ 31	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	2	6.1	1	5.2	5	5.6	5	5.3
Adjustments to prior year taxes	(2)	(6.1)	(1)	(4.8)	(2)	(2.2)	(1)	(1.1)
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	2	9.5	—	—	(3)	(3.1)
Depreciation	(1)	(3.0)	—	(0.5)	(1)	(1.1)	—	—
Other, net	—	1.3	1	3.2	—	0.5	—	0.3
Income tax expense	$ 11	33.3%	$ 10	47.6%	$ 34	37.8%	$ 32	36.4%

Three Months Ended September 30, 2012 and 2011

DPL's effective income tax rates for the three months ended September 30, 2012 and 2011 were 33.3% and 47.6%, respectively. The decrease in the effective income tax rate primarily resulted from adjustments to prior year taxes, tax benefits related to depreciation and changes in estimates and interest related to uncertain and effectively settled tax positions as discussed below.

In the third quarters of 2012 and 2011, DPL recorded reductions of $2 million and $1 million related to certain non-recurring adjustments to prior year taxes. Further, in the third quarter of 2012, DPL also recorded additional tax benefits related to depreciation on property, plant and equipment purchased prior to 1975.

In addition, in the third quarter of 2011, DPL recalculated interest on its uncertain tax positions for open tax years using different assumptions related to the application of its deposit made with the Internal Revenue Service (IRS) in 2006 which results in an additional tax expense in the third quarter of 2011 of $1 million (after-tax).

Nine Months Ended September 30, 2012 and 2011

DPL's effective income tax rates for the nine months ended September 30, 2012 and 2011 were 37.8% and 36.4%, respectively. The increase in the effective income tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

During the second quarter of 2011, PHI reached a settlement with the IRS with respect to interest due on its federal tax liabilities related to the tax years 1996 through 2002. In connection with this agreement, PHI reallocated certain amounts that have been on deposit with the IRS since 2006 among liabilities in the settlement years and subsequent years. Primarily related to the settlement and reallocations, DPL recorded an additional $4 million (after-tax) interest benefit in the second quarter of 2011. This benefit is partially offset by the adjustments recorded in the third quarter of 2011 related to DPL's settlement with the state taxing authorities resulting in $1 million (after-tax) of additional tax expense, and tax expense of $1 million (after-tax) associated with the recalculation of interest on uncertain tax positions for open tax years using different assumptions related to the application of its deposit made with the IRS in 2006.

The increase in the effective income tax rate was partially offset by the adjustments to prior year taxes and tax benefits related to depreciation discussed above.

(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 September 30, 2012 and December 31, 2011:

	As of September 30, 2012				
Balance Sheet Caption	Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
			(millions of dollars)		
Derivative assets (current assets)	$ —	$ 1	$ 1	$ (1)	$ —
Total Derivative assets	—	1	1	(1)	—
Derivative liabilities (current liabilities)	—	(7)	(7)	—	(7)
Derivative liabilities (non-current liabilities)	—	—	—	—	—
Total Derivative liabilities	—	(7)	(7)	—	(7)
Net Derivative (liability) asset	$ —	$ (6)	$ (6)	$ (1)	$ (7)

	As of December 31, 2011				
Balance Sheet Caption	Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
			(millions of dollars)		
Derivative liabilities (current liabilities)	$ —	$ (14)	$ (14)	$ 2	$ (12)
Derivative liabilities (non-current liabilities)	—	(3)	(3)	—	(3)
Total Derivative liabilities	—	(17)	(17)	2	(15)
Net Derivative (liability) asset	$ —	$ (17)	$ (17)	$ 2	$ (15)

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. The amount of cash collateral that was offset against these derivative positions is as follows:

	September 30, 2012	December 31, 2011
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim	$ —	$ 2
Cash collateral received from counterparties with the obligation to return	(1)	—

As of December 31, 2011, all DPL 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

All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all of DPL's gains and losses related to hedging activities, are deferred under FASB guidance on regulated operations until recovered from customers based on the fuel adjustment clause approved by the DPSC. The following table indicates the net unrealized derivative losses arising during the period that were deferred as Regulatory assets and the net realized losses recognized in the statements of income (through Purchased energy or Gas purchased expense) that were also deferred as Regulatory assets for the three and nine months ended September 30, 2012 and 2011 associated with cash flow hedges:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Net unrealized loss arising during the period	$ —	$ (1)	$ —	$ (1)
Net realized losses recognized during the period	—	(2)	—	(5)

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.

The following table indicates the net unrealized derivative losses arising during the period that were deferred as 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 for the three and nine months ended September 30, 2012 and 2011 associated with these derivatives:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Net unrealized gain (loss) arising during the period	$ 2	$ (4)	$ (2)	$ (6)
Net realized losses recognized during the period	(2)	(3)	(13)	(14)

As of September 30, 2012 and December 31, 2011, DPL had the following net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting:

	September 30, 2012		December 31, 2011	
Commodity	Quantity	Net Position	Quantity	Net Position
Natural gas (One Million British Thermal Units (MMBtu))	3,571,000	Long	6,161,200	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 debt rating of the holder.

The gross fair values of DPL's derivative liabilities with credit-risk-related contingent features as of September 30, 2012 and December 31, 2011, were $7 million and $15 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 $7 million and $15 million, respectively. If DPL's debt ratings had been downgraded below investment grade as of September 30, 2012 and December 31, 2011, DPL's net settlement amounts would have been approximately $8 million and $15 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately $8 million and $15 million, respectively, in addition to that which was posted as of September 30, 2012 and December 31, 2011. 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. At September 30, 2012 and December 31, 2011, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries was $563 million and $711 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 September 30, 2012 and December 31, 2011. 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 September 30, 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)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Cash equivalents				
Treasury fund	40	40	—	—
Executive deferred compensation plan assets				
Money market funds	2	2	—	—
Life insurance contracts	1	—	—	1
	$ 44	$ 43	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 7	$ —	$ —	$ 7
	$ 7	$ —	$ —	$ 7

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

Description	Total	Fair Value Measurements at December 31, 2011 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	$ 2	$ 2	$ —	$ —
Life insurance contracts	1	—	—	1
	$ 3	$ 2	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 17	$ 2	$ —	$ 15
	$ 17	$ 2	$ —	$ 15

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2011.
(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 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 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 the forward price curves, contract prices, contract volumes, the risk-free rate and the 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.

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 September 30, 2012:

Type of Instrument	Fair Value at September 30, 2012 (millions of dollars)	Valuation Technique	Unobservable Input	Range
Natural gas options	$ (7)	Option model	Volatility factor	0.82 – 2.76

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 September 30, 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 DPL for reasonableness.

Reconciliations of the beginning and ending balances of DPL's fair value measurements using significant unobservable inputs (level 3) for the nine months ended September 30, 2012 and 2011 are shown below:

	Nine Months Ended September 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	(2)	—
Purchases	—	—
Issuances	—	—
Settlements	10	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ (7)	$ 1

	Nine Months Ended September 30, 2011	
	Natural Gas	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ (23)	$ 1
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory assets	(6)	—
Purchases	—	—
Issuances	—	—
Settlements	11	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ (18)	$ 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 September 30, 2012 are shown in the table 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 in active markets, but not 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 September 30, 2012			
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)	$996	$ 278	$ 603	$ 115
	$996	$ 278	$ 603	$ 115

(a) The carrying amount for Long-term debt is $917 million as of September 30, 2012.

The estimated fair value of DPL's debt instruments at December 31, 2011 is shown below:

	December 31, 2011	
	Carrying Amount	**Fair Value**
	(millions of dollars)	
Long-term debt	$ 765	$834

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

(13) COMMITMENTS AND CONTINGENCIES

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 described below of DPL at September 30, 2012 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Other	Total
		(millions of dollars)		
Beginning balance as of January 1	$ 1	$ 4	$ 2	$ 7
Accruals	—	—	—	—
Payments	—	(1)	—	(1)
Ending balance as of September 30	1	3	2	6
Less amounts in Other current liabilities	1	1	2	4
Amounts in Other deferred credits	$ —	$ 2	$—	$ 2

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, 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. Although DPL cannot at this time 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 and therefore, costs incurred to resolve this matter are not expected to be material.

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."

(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 September 30, 2012 and 2011 were approximately $40 million and $35 million, respectively. PHI Service Company costs directly charged or allocated to DPL for the nine months ended September 30, 2012 and 2011 were approximately $114 million and $97 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Purchased power under Default Electricity Supply contracts with Conectiv Energy Supply, Inc. (a)	$ —	$ —	$ —	$ 1
Intercompany lease transactions (b)	1	1	3	3

(a) Included in Purchased energy expense.
(b) Included in Electric revenue.

As of September 30, 2012 and December 31, 2011, DPL had the following balances on its balance sheets due to related parties:

	September 30, 2012	December 31, 2011
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (23)	$ (20)
Conectiv Energy Supply, Inc.	—	(1)
Total	$ (23)	$ (21)

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Operating Revenue	$ 413	$ 399	$ 939	$ 1,018
Operating Expenses				
Purchased energy	226	254	555	648
Other operation and maintenance	66	61	178	167
Depreciation and amortization	37	41	92	107
Other taxes	6	8	14	19
Deferred electric service costs	29	(17)	(6)	(49)
Total Operating Expenses	364	347	833	892
Operating Income	49	52	106	126
Other Income (Expenses)				
Interest expense	(17)	(18)	(52)	(51)
Other income	1	—	3	2
Total Other Expenses	(16)	(18)	(49)	(49)
Income Before Income Tax Expense	33	34	57	77
Income Tax Expense	13	17	21	36
Net Income	$ 20	$ 17	$ 36	$ 41

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 7	$ 91
Restricted cash equivalents	14	11
Accounts receivable, less allowance for uncollectible accounts of $13 million and $12 million, respectively	232	185
Inventories	30	25
Prepayments of income taxes	27	26
Income taxes receivable	5	5
Prepaid expenses and other	27	16
Total Current Assets	342	359
INVESTMENTS AND OTHER ASSETS		
Regulatory assets	696	662
Prepaid pension expense	91	71
Income taxes receivable	133	61
Restricted cash equivalents	15	15
Assets and accrued interest related to uncertain tax positions	22	42
Derivative assets	8	—
Other	12	14
Total Investments and Other Assets	977	865
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	2,699	2,548
Accumulated depreciation	(784)	(766)
Net Property, Plant and Equipment	1,915	1,782
TOTAL ASSETS	$ 3,234	$ 3,006

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 116	$ 23
Current portion of long-term debt	108	37
Accounts payable and accrued liabilities	143	117
Accounts payable due to associated companies	16	14
Taxes accrued	11	10
Interest accrued	20	15
Other	43	45
Total Current Liabilities	457	261
DEFERRED CREDITS		
Regulatory liabilities	109	60
Deferred income taxes, net	772	698
Investment tax credits	6	7
Other postretirement benefit obligations	35	31
Derivative liabilities	9	—
Other	16	20
Total Deferred Credits	947	816
LONG-TERM LIABILITIES		
Long-term debt	760	832
Transition Bonds issued by ACE Funding	267	295
Total Long-Term Liabilities	1,027	1,127
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	576	576
Retained earnings	201	200
Total Equity	803	802
TOTAL LIABILITIES AND EQUITY	$ 3,234	$ 3,006

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

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

	Nine Months Ended September 30, 2012	2011
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 36	$ 41
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	92	107
Deferred income taxes	72	39
Changes in:		
Accounts receivable	(47)	(12)
Inventories	(5)	(7)
Prepaid expenses	(12)	(25)
Regulatory assets and liabilities, net	(20)	(58)
Accounts payable and accrued liabilities	26	(2)
Pension contributions	(30)	(30)
Income tax-related prepayments, receivables and payables	(51)	49
Other assets and liabilities	13	20
Net Cash From Operating Activities	74	122
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(186)	(96)
Department of Energy capital reimbursement awards received	2	3
Net other investing activities	(3)	(11)
Net Cash Used By Investing Activities	(187)	(104)
FINANCING ACTIVITIES		
Capital contribution from Parent	—	60
Dividends paid to Parent	(35)	—
Redemption of preferred stock	—	(6)
Issuances of long-term debt	—	200
Reacquisitions of long-term debt	(30)	(25)
Issuances (repayments) of short-term debt, net	93	(158)
Net other financing activities	1	(2)
Net Cash From Financing Activities	29	69
Net (Decrease) Increase in Cash and Cash Equivalents	(84)	87
Cash and Cash Equivalents at Beginning of Period	91	4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 7	$ 91
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid (received) for income taxes (includes payments from PHI for federal income taxes)	$ 4	$ (51)

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, 2011	8,546,017	$ 26	$ 576	$ 200	$802
Net income	—	—	—	2	2
BALANCE, MARCH 31, 2012	8,546,017	26	576	202	804
Net income	—	—	—	14	14
Dividends on common stock	—	—	—	(15)	(15)
BALANCE, JUNE 30, 2012	8,546,017	26	576	201	803
Net income	—	—	—	20	20
Dividends on common stock	—	—	—	(20)	(20)
BALANCE, SEPTEMBER 30, 2012	8,546,017	$ 26	$ 576	$ 201	$803

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, 2011, as amended to include the executive compensation and other information required by Part III of Form 10-K (which information originally had been omitted as permitted by that form). In the opinion of ACE's management, the consolidated financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly ACE's financial condition as of September 30, 2012, in accordance with GAAP. The year-end December 31, 2011 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 nine months ended September 30, 2012 may not be indicative of ACE's results that will be realized for the full year ending December 31, 2012.

Use of Estimates

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

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset impairment evaluations, fair value calculations for derivative instruments, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of 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.

Storm Restoration Costs

On June 29, 2012, ACE was affected by a rapidly moving thunderstorm with hurricane-force winds, known as a "derecho," which resulted in widespread customer outages in its service territory. The derecho caused extensive damage to ACE's electric transmission and distribution systems. Storm restoration activity commenced immediately following the storm and continued into July 2012, with the majority of the incremental storm restoration costs occurring in the third quarter of 2012.

Total incremental storm restoration costs incurred by ACE through September 30, 2012 were $36 million, with $13 million incurred for repair work and $23 million incurred as capital expenditures. All of the costs incurred for repair work of $13 million were deferred as regulatory assets to reflect the probable recovery of these storm restoration costs. As of September 30, 2012, total incremental storm restoration costs include $12 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. ACE will be pursuing recovery of the incremental storm restoration costs in its next distribution base rate case.

General and Auto Liability

For the three and nine months ended September 30, 2012, ACE increased its self-insurance reserves for general and auto liability claims by approximately $1 million based on obtaining an actuarial estimate of the unpaid losses attributed to general and auto liability claims for ACE at September 30, 2012. During the second quarter of 2011, ACE reduced its self-insurance reserves for general and auto liability claims by approximately $1 million, based on obtaining an actuarial estimate of the unpaid losses attributed to general and auto liability claims for ACE at June 30, 2011.

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. As of September 30, 2012, ACE was 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.

Net purchase activities with the NUGs for the three months ended September 30, 2012 and 2011 were approximately $56 million and $57 million, respectively, of which approximately $53 million and $55 million, respectively, consisted of power purchases under the PPAs. Net purchase activities with the NUGs for the nine months ended September 30, 2012 and 2011 were approximately $156 million and $169 million, respectively, of which approximately $151 million and $159 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 consolidates ACE Funding in its 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. The annual share of payments to or receipts by ACE and the other EDCs is based upon each company's annual proportion of the total New Jersey load attributable to all EDCs, which is currently estimated to be approximately 15 percent for ACE. The NJBPU has approved full recovery from distribution customers of payments made by ACE and the other EDCs, and distribution customers would be entitled to any payments received from the generation companies. For additional discussion about the SOCAs, see Note (6), "Regulatory Matters."

In May 2012, all three generation companies under the SOCAs bid into the PJM 2015-2016 capacity auction and two of the generators cleared that capacity auction. ACE recorded a derivative asset (liability) for the estimated fair value of each SOCA and recorded an offsetting regulatory liability (asset) as described in more detail in Note (10), "Derivative Instruments and Hedging Activities," and Note (11), "Fair Value Disclosures." FASB guidance on derivative accounting and the accounting for regulated operations would apply to ACE's obligations under the third SOCA once the related capacity has cleared a PJM auction. The next PJM capacity auction is scheduled for May 2013. ACE has concluded that consolidation is not required for the SOCAs under the FASB guidance on the consolidation of variable interest entities.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in ACE's gross revenues were $6 million and $7 million for the three months ended September 30, 2012 and 2011, respectively, and $13 million and $17 million for the nine months ended September 30, 2012 and 2011, respectively.

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.

Income Tax Expense Adjustment

During the second quarter of 2011, ACE completed a reconciliation of its deferred taxes associated with certain regulatory assets and recorded adjustments that resulted in an increase to Income tax expense of $1 million for the nine months ended September 30, 2011.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Fair Value Measurements and Disclosures (ASC 820)

The FASB issued new guidance on fair value measurement and disclosures that was effective beginning with ACE's March 31, 2012 consolidated financial statements. The new measurement guidance did not have a material impact on ACE's consolidated financial statements and the new disclosure requirements are in Note (11), "Fair Value Disclosures," of ACE's consolidated financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosures will include information about the gross exposures 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. The new disclosures are effective beginning with ACE's March 31, 2013 consolidated financial statements. ACE is 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 August 5, 2011, ACE filed a petition with the NJBPU to increase its electric distribution rates by the net amount of approximately $54.6 million (which was increased to approximately $74.3 million on February 24, 2012, to reflect the 2011 test year), based on a requested return on equity (ROE) of 10.75%. The modified net increase consists of a rate increase proposal of approximately $90.3 million, less a deduction from base rates of approximately $16 million through a credit rider expected to expire August 31, 2013, which is designed to refund to customers certain excess depreciation reserve funds as previously directed by the NJBPU (the Excess Depreciation Rider). ACE also proposed an increase of approximately $6.3 million in sales-and-use taxes related to the increase in base rates. On October 23, 2012, the NJBPU approved a stipulation of settlement signed by the parties (the New Jersey Settlement), which provides for an annual increase in ACE's electric distribution base rates by the net amount of approximately $28 million, based on an ROE that, as part of the overall settlement, is deemed to be 9.75%. The net increase consists of a rate increase of approximately $44 million, less a deduction from base rates of approximately $16 million through the Excess Depreciation Rider. Upon expiration of the Excess Depreciation Rider, ACE will not realize an increase in operating income because the resulting increase in revenues will be offset by a substantially similar increase in depreciation expense. The New Jersey Settlement also provides for an increase of approximately $2 million in sales-and-use taxes related to the increase in base rates, and allows ACE to fully amortize over a three-year period the approximately $7.7 million in costs incurred as a result of Hurricane Irene in August 2011. The new rates will become effective for utility services rendered on and after November 1, 2012.

Infrastructure Investment Program

In July 2009, the NJBPU approved certain rate recovery mechanisms in connection with ACE's Infrastructure Investment Program (the IIP). In exchange for the increase in infrastructure investment, the NJBPU, through the IIP, allowed recovery by ACE of its infrastructure investment capital expenditures through a special rate outside the normal rate recovery mechanism of a base rate filing. The IIP was designed to stimulate the New Jersey economy and provide incremental employment in ACE's service territory by increasing the infrastructure expenditures to a level above otherwise normal budgeted levels. In an October 18, 2011 petition (subsequently amended December 16, 2011) filed with the NJBPU, ACE requested an extension and expansion to the IIP. The New Jersey Settlement provides for full cost recovery of ACE's initial IIP, but requires ACE to withdraw its request for extension and expansion to the IIP, without prejudice to file such request again in the future.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012, ACE filed 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 that fund several statewide social programs 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. The net impact of adjusting the charges as proposed (consisting of both the annual impact of the proposed 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, 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. On June 18, 2012, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates to go into effect on July 1, 2012. The rates are deemed "provisional" because ACE's filing will not be updated for actual revenues and expenses (if necessary) for May and June 2012 until after July 1, 2012 and a review of the final underlying costs for reasonableness and prudency will be completed after such filing.

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 (10), "Derivative Instruments and Hedging Activities." ACE and the other New Jersey EDCs entered into the SOCAs under protest based on concerns about the potential cost to distribution customers. In May 2011, the NJBPU denied a joint motion for reconsideration of its order requiring each of the EDCs to enter into the SOCAs. In June 2011, ACE and the other EDCs filed appeals related to the NJBPU orders with the Appellate Division of the New Jersey Superior Court. On March 5, 2012, the court remanded the case to the NJBPU with instructions to refer the case to an Administrative Law Judge for further consideration. The matter has been transmitted by the NJBPU to the Office of Administrative Law and remains pending.

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 constitutionality of the New Jersey law under which the SOCAs were established. On September 28, 2012, the District Court denied motions for summary judgment filed by ACE and the other plaintiffs, as well as cross-motions filed by defendants. The litigation remains pending.

In October 2011 and January 2012, respectively, two of the three generation companies sent notices of dispute under the SOCA to ACE. The notices of dispute alleged that certain actions taken by PJM will have an adverse effect on the generation company's ability to clear their transactions in the PJM auction, which is required for payment under the SOCA. The two generation companies filed separate petitions with the NJBPU seeking to amend their respective SOCAs and, in April 2012, the NJBPU issued an order consolidating the two matters. In May 2012, the NJBPU denied all of the generation companies' requests without prejudice to their right to raise the issues at a later date.

(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 September 30, 2012 and 2011, before intercompany allocations from the PHI Service Company, were $28 million and $24 million, respectively. ACE's allocated share was $6 million and $5 million, respectively, for the three months ended September 30, 2012 and 2011. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2012 and 2011, before intercompany allocations from the PHI Service Company, were $84 million and $70 million, respectively. ACE's allocated share was $18 million and $15 million, respectively, for the nine months ended September 30, 2012 and 2011.

In the first quarter of 2012, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan of $30 million. In the first quarter of 2011, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan in the amount of $30 million.

(8) DEBT

Credit Facility

PHI, Potomac Electric Power Company (Pepco), Delmarva Power & Light Company (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 among other changes, extended the expiration date of the facility to August 1, 2016. On August 2, 2012, the amended and restated credit agreement 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.

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 initial credit sublimit for PHI is $750 million 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 at September 30, 2012.

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.

At September 30, 2012 and December 31, 2011, 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 $563 million and $711 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 September 30, 2012, the maximum capacity available under the program was $250 million, subject to available borrowing capacity under the credit facility.

ACE had $93 million of commercial paper outstanding at September 30, 2012. The weighted average interest rate for commercial paper issued by ACE during the nine months ended September 30, 2012 was 0.42% and the weighted average maturity of all commercial paper issued by ACE during the nine months ended September 30, 2012 was three days.

Other Financing Activities

In July 2012, ACE Funding made principal payments of $6 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

On September 28, 2012, ACE redeemed, prior to maturity, $4 million of its 5.60% tax-exempt pollution control revenue bonds due 2025 issued by the Industrial Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit. Contemporaneously with this redemption, ACE redeemed, prior to maturity, $4 million of its outstanding 5.60% first mortgage bonds due 2025 that secured the obligations under the pollution control bonds.

(9) INCOME TAXES

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 11	35.0%	$ 12	35.0%	$ 20	35.0%	$27	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	2	6.1	2	4.4	3	5.3	5	5.9
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	4	10.5	—	—	4	5.1
Deferred tax adjustment	—	—	—	—	—	—	1	1.7
Other, net	—	(1.7)	(1)	0.1	(2)	(3.5)	(1)	(0.9)
Consolidated income tax expense	$ 13	39.4%	$ 17	50.0%	$ 21	36.8%	$36	46.8%

Three Months ended September 30, 2012 and 2011

ACE's consolidated effective income tax rates for the three months ended September 30, 2012 and 2011 were 39.4% and 50.0%, respectively. The decrease in the effective income tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

During the third quarter of 2011 the company recalculated interest on its uncertain tax positions for open tax years using different assumptions related to the application of its deposit made with the Internal Revenue Service in 2006. This resulted in an additional tax expense of $3 million (after-tax).

Nine Months ended September 30, 2012 and 2011

ACE's consolidated effective income tax rates for the nine months ended September 30, 2012 and 2011 were 36.8% and 46.8%, respectively. The decrease in the effective income tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions and a deferred tax adjustment.

During the second quarter of 2011, PHI reached a settlement with the Internal Revenue Service (IRS) with respect to interest due on its federal tax liabilities related to the November 2010 audit settlement for years 1996 through 2002. In connection with this agreement, PHI reallocated certain amounts that have been on deposit with the IRS since 2006 among liabilities in the settlement years and subsequent years. Primarily related to the settlement and reallocations, ACE has recorded an additional $1 million (after-tax) of interest due to the IRS. This additional interest expense was recorded in the second quarter of 2011. This is further impacted by the adjustment recorded in the third quarter of 2011 related to the recalculation of interest on its uncertain tax positions for open tax years using different assumptions related to the application of its deposit made with the Internal Revenue Service in 2006.

Also during the second quarter of 2011, ACE completed a reconciliation of its deferred taxes on certain regulatory assets and, as a result, recorded a $1 million increase to income tax expense as shown in the "Deferred Tax Adjustment" line above.

(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. Changes in the fair value of the derivatives embedded in the SOCAs are deferred as regulatory assets or 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 September 30, 2012, ACE had other non-current derivative assets of $8 million and non-current derivative liabilities of $9 million associated with the two SOCAs and an offsetting regulatory liability and asset, respectively, of the same amounts. As of September 30, 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 an unrealized loss of $1 million for the three and nine months ended September 30, 2012, have been deferred as regulatory liabilities and assets, respectively, as of September 30, 2012.

(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 September 30, 2012 and December 31, 2011. 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.

Description	Total	Fair Value Measurements at September 30, 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 (c)	$ 8	$ —	$ —	$ 8
Cash equivalents				
Treasury fund	28	28	—	—
	$ 36	$ 28	$ —	$ 8
LIABILITIES				
Derivative instruments (b)				
Capacity (c)	$ 9	$ —	$ —	$ 9
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
	$ 10	$ —	$ 1	$ 9

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2012.
(b) The fair value of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents derivatives associated with ACE SOCAs.

Description	Total	Fair Value Measurements at December 31, 2011 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	$114	$ 114	$ —	$ —
	$114	$ 114	$ —	$ —
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 1	$ —	$ 1	$ —
	$ 1	$ —	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2011.

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 consulting firm 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 table below summarizes the primary unobservable input used to determine the fair value of ACE's level 3 instruments and the range of values that could be used for the input as of September 30, 2012:

Type of Instrument	Fair Value at September 30, 2012 *(millions of dollars)*	Valuation Technique	Unobservable Input	Range
Capacity contracts, net	$ (1)	Discounted cash flow	Discount rate	5% - 9%

ACE used a value 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 September 30, 2012.

A reconciliation of the beginning and ending balances of ACE's fair value measurements using significant unobservable inputs (level 3) for the nine months ended September 30, 2012 is shown below:

	Capacity Nine Months Ended September 30, 2012 *(millions of dollars)*
Beginning balance as of January 1	$ —
Total gains (losses) (realized and unrealized):	
Included in income	—
Included in accumulated other comprehensive loss	—
Included in regulatory assets	(1)
Purchases	—
Issuances	—
Settlements	—
Transfers in (out) of level 3	—
Ending balance as of September 30	$ (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 level of the estimates within the fair value hierarchy as of September 30, 2012 are shown in the table 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 in active markets, but not on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and ACE reviews the methodologies and results.

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

	Fair Value Measurements at September 30, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,029	$ —	$ 894	$ 135
Transition Bonds issued by ACE Funding (b)	355	—	355	—
	$1,384	$ —	$ 1,249	$ 135

(a) The carrying amount for Long-term debt is $829 million as of September 30, 2012.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $306 million as of September 30, 2012.

The estimated fair values of ACE's debt instruments at December 31, 2011 are shown below:

	December 31, 2011	
	Carrying Amount	Fair Value
	(millions of dollars)	
Long-term debt	$ 832	$1,003
Transition Bonds issued by ACE Funding	332	380

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. A trial date has been set for May 20, 2013.

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 ACE's customers, 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 described below of ACE at September 30, 2012 are summarized as follows:

	Legacy Generation - Regulated	Total
	(millions of dollars)	
Beginning balance as of January 1	$ 1	$ 1
Accruals	—	—
Payments	—	—
Ending balance as of September 30	1	1
Less amounts in Other current liabilities	—	—
Amounts in Other deferred credits	$ 1	$ 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 estimates the additional cost for future response measures will be approximately $6 million. ACE believes that EPA sent similar general notice letters to three other companies and various individuals.

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, 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. Although ACE cannot at this time 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 and therefore, costs incurred to resolve this matter are not expected to be material.

(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 September 30, 2012 and 2011 were approximately $31 million and $27 million, respectively. PHI Service Company costs directly charged or allocated to ACE for the nine months ended September 30, 2012 and 2011 were approximately $86 million and $75 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Meter reading services provided by Millennium Account Services LLC (an ACE affiliate) (a)	$ (1)	$ (1)	$ (3)	$ (3)
Intercompany lease transactions (a)	—	—	(1)	(1)
Intercompany use revenue (b)	—	1	1	2

(a) Included in Other operation and maintenance expense.
(b) Included in operating revenue.

As of September 30, 2012 and December 31, 2011, ACE had the following balances on its consolidated balance sheets due to related parties:

	September 30, 2012	December 31, 2011
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (15)	$ (12)
Other	(1)	(2)
Total	$ (16)	$ (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

Pepco Holdings, 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, primarily to commercial, industrial and government customers and is in the process of winding down its competitive electricity and natural gas retail supply business. Each of Power Delivery and Pepco Energy Services constitutes a separate segment for financial reporting purposes. A third segment, Other Non-Regulated, consists of a portfolio of cross-border energy lease investments.

The following table sets forth the percentage contributions to consolidated operating revenue and consolidated operating income from continuing operations attributable to PHI's segments.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Percentage of Consolidated Operating Revenue				
Power Delivery	90%	81%	85%	78%
Pepco Energy Services	9%	19%	14%	21%
Other (a)	1%	—	1%	1%
Percentage of Consolidated Operating Income				
Power Delivery	75%	83%	76%	76%
Pepco Energy Services	2%	6%	7%	8%
Other (a)	23%	11%	17%	16%
Percentage of Power Delivery Operating Revenue				
Power Delivery Electric	98%	98%	96%	95%
Power Delivery Gas	2%	2%	4%	5%

(a) For presentation purposes, this category includes Other Non-Regulated and Corporate and Other.

Power Delivery

Power Delivery Electric consists primarily of the transmission, distribution and default supply of electricity, and Power Delivery Gas consists of the delivery and supply of natural gas. Power Delivery represents a single operating segment for financial reporting purposes.

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 quarterly 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, and in the case of DPL, natural gas. 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 in some jurisdictions, 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) for retail customers 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 has been approved in concept by the Delaware Public Service Commission (DPSC) and is pending development of an implementation plan and a customer education plan.

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.

Reliability Enhancement and Emergency Restoration Improvement Plans

In 2010, PHI announced that Pepco had adopted and begun to implement comprehensive reliability enhancement plans in Maryland and the District of Columbia. These reliability enhancement plans include various initiatives to improve electrical system reliability, such as:

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

In 2011, PHI also initiated a program to improve Pepco's emergency restoration efforts that included, among other initiatives, an expansion and enhancement of customer service capabilities. PHI has extended its reliability enhancement efforts to DPL and ACE.

In 2012, PHI has continued to focus on its reliability enhancement and emergency restoration improvement plans in all of its service territories.

Blueprint for the Future

Each of PHI's three utilities is participating in a PHI initiative referred to as "Blueprint for the Future." The installation of smart meters (also known as advanced metering infrastructure (AMI)), is a key initiative of Blueprint for the Future. As of September 30, 2012, installation and activation of smart meters was complete for DPL electric customers in Delaware. For Pepco, meter installation is substantially complete for residential customers in the District of Columbia, and is expected to be complete in the first half of 2013 for residential customers in Maryland. The respective public service commissions have approved the creation of regulatory assets to defer AMI costs between rate cases, as well as the accrual of a return on the deferred costs. Thus, these costs will be recovered through base rates in the future. 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.

On May 8, 2012, the MPSC issued an order permitting DPL to proceed with its deployment of an AMI system in Maryland and establish a regulatory asset for AMI system incremental costs. On October 25, 2012, DPL filed with the MPSC a proposed customer education and communications plan, which subject to commission approval, will be implemented in advance of its Maryland AMI deployment. Approval of AMI has been deferred by the NJBPU for ACE in New Jersey.

Dynamic pricing will provide a bill credit to SOS customers for decreasing their energy use during those times when energy demand and, consequently, the cost of supplying electricity, are higher. In 2011, the DPSC approved DPL's request to implement dynamic pricing for its Delaware customers. In Delaware, approximately 6,700 SOS customers participated in the phase-in stage of the program in 2012; the remaining SOS customers will be eligible to participate in 2013. For DPL's Maryland customers, dynamic pricing has been approved in concept, with implementation to begin once AMI has been installed. In Pepco's Maryland service territory, dynamic pricing has been approved in concept, and a phase-in for approximately 5,000 residential customers has been completed; the remaining Maryland customers will be eligible to participate in 2013. In Pepco's District of Columbia jurisdiction, proposals are pending. Dynamic pricing has been deferred by the NJBPU for ACE's customers in New Jersey.

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 their investment in the rate base and their operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, Pepco's and DPL's most recent Delaware, District of Columbia and Maryland base rate case filings 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. See Note (7), "Regulatory Matters – Rate Proceedings," to the consolidated financial statements of PHI for a discussion of each of these mechanisms. In both the Pepco and DPL base rate case orders in Maryland, the MPSC did not approve 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 District of Columbia Public Service Commission (DCPSC) denied Pepco's request for approval of a RIM, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases. In Delaware, the parties to DPL's electric base rate case entered into a settlement agreement, which remains subject to DPSC approval, that does not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it does provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag.

In Maryland, the governor forwarded to the MPSC a report issued by his Grid Resiliency Task Force (see Note (7), "Regulatory Matters – Maryland Governor's Grid Resiliency Task Force" to the consolidated financial statements of PHI for additional discussion), urging the MPSC to quickly implement certain Task Force recommendations that would, among other things, accelerate reliability improvement investments and allow surcharge recovery for the accelerated investments. Pepco and DPL are currently evaluating the report and its recommendations to determine what effect, if any, they may have on proposals to be made in their future electric distribution base rate cases in Maryland to, among other things, mitigate the effects of regulatory lag. The form and substance of any such proposals will also depend, in part, on how the MPSC responds to the report and the governor's request.

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 rate recovery mechanisms or base rate cases will fully mitigate the effects of regulatory lag. Until such time as any proposed or alternative 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 related cash flow levels of PHI's utility subsidiaries with other operation and maintenance spending and capital investments. In light of the MPSC's decisions in the most recent Pepco and DPL base rate cases, Pepco intends to file its next electric distribution base rate case with the MPSC in the fourth quarter of 2012 and DPL intends to file its next electric distribution base rate case with the MPSC in the first quarter of 2013. Pepco also intends to file its next electric distribution base rate case with the DCPSC in the first quarter of 2013.

Termination of the MAPP Project

On August 24, 2012, the board of PJM notified PHI, on behalf of its subsidiaries Pepco and DPL, that the Mid-Atlantic Power Pathway (MAPP) project has been terminated and removed from PJM's regional transmission expansion plan. PHI was originally 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 of PJM's decision, on October 2, 2012, Pepco and DPL filed with the MPSC a notice withdrawing their pending applications related to the MAPP project. PHI had included in its five-year projected capital expenditures $205 million of MAPP-related expenditures for the period from 2012 to 2016. PHI has updated its five-year projected capital expenditures to remove the MAPP-related expenditures to reflect the PJM decision. See "Capital Resources and Liquidity – Capital Requirements – Capital Expenditures" for a discussion of PHI's projected capital expenditures.

As of September 30, 2012, PHI's total capital expenditures for the MAPP project were approximately $101 million. Under the terms of the FERC order approving an incentive rate for the MAPP project, FERC authorized the recovery of abandoned costs prudently incurred in connection with the MAPP project. Consistent with this order, PHI intends to seek recovery of abandoned MAPP capital expenditures through a filing expected to be submitted to the FERC in the fourth quarter of 2012. The FERC filing is expected to address, among other things, the period over which the abandoned costs are to be recovered and the rate of return on these costs during the recovery period. Under an order issued by the FERC in 2008, PHI is currently allowed to include its MAPP capital expenditures in its rate base, earning an incentive rate of return of 12.8% during the construction period.

As of September 30, 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, and reclassified the remaining $90 million of capital expenditures to a regulatory asset. 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 the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

Pepco Energy Services

Pepco Energy Services is engaged in the following businesses:

- providing energy efficiency services principally to federal, state and local government customers, and designing, constructing and operating combined heat and power and central energy plants,
- providing high voltage electric 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. area, and
- providing retail customers electricity and natural gas under its remaining contractual obligations.

Pepco Energy Services has been focused since 2010 on growing its energy efficiency 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 has slowed in 2012, driven by, among other factors, lower energy prices that have lessened the economic benefits of energy efficiency projects and the reluctance of state and local governments to incur new debt associated with energy efficiency projects. Given the slowdown in the state and local government markets, Pepco Energy Services believes that new business in these markets will remain challenged for the foreseeable future. Consequently, Pepco Energy Services is reducing resources and personnel and limiting geographic expansion in the energy efficiency services business, while focusing its existing resources on developing business in the federal government market and continuing to pursue combined heat and power projects.

Most of Pepco Energy Services' contracts with federal, state and local governments, as well as independent agencies such as housing and water authorities, contain provisions authorizing the governmental authority or independent agency to terminate the contract at any time. Those provisions include explicit mechanisms that, if exercised, would require the other party to pay Pepco Energy Services for work performed through the date of termination and for additional costs incurred as a result of the termination. In addition, Pepco Energy Services provides energy services guarantees in connection with its energy services performance contracts.

PHI guarantees the obligations of Pepco Energy Services under certain of its energy efficiency, combined heat and power and construction contracts. At September 30, 2012, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $199 million.

Pepco Energy Services also has historically been engaged in the business of providing retail energy supply services, consisting of the sale of electricity, including electricity from renewable resources, primarily to commercial, industrial and government customers located primarily in the mid-Atlantic and northeastern regions of the United States, as well as Texas and Illinois, and the sale of natural gas to customers located primarily in the mid-Atlantic region. In December 2009, PHI announced that it will wind down the retail energy supply component of the Pepco Energy Services business.

Pepco Energy Services' retail natural gas sales volumes and revenues are seasonally dependent. Colder weather from November through March of each year generally translates into increased sales volumes, which, when coupled with higher natural gas prices during these months, allows Pepco Energy Services to recognize generally higher revenues as compared to other months of the year. Retail electricity sales volumes are also seasonally dependent, with sales in the summer and winter months being generally higher than other months of the year, which, when coupled with higher electricity prices during these periods, allows Pepco Energy Services to recognize generally higher revenues as compared to other periods during the year. The impact of this seasonality on Pepco Energy Services' results is diminishing with the wind-down of the business. The energy services business is not seasonal.

To effectuate the wind-down of the retail energy supply business, Pepco Energy Services is continuing to fulfill all of its commercial and regulatory obligations and perform its customer service functions to ensure that it meets the needs of its existing customers, but is not entering into any new retail energy supply contracts. Operating revenues related to the retail energy supply business for the three months ended September 30, 2012 and 2011 were $77 million and $222 million, respectively, and operating income for the same periods was $13 million and $5 million, respectively. Operating revenues related to the retail energy supply business for the nine months ended September 30, 2012 and 2011 were $349 million and $765 million, respectively, and operating income for the same periods was $44 million and $21 million, respectively.

PHI expects the operating results of the retail energy supply business, excluding the effects of unrealized mark-to-market gains or losses on derivatives contracts, to be profitable in 2012, based on its existing retail contracts and its corresponding portfolio of wholesale hedges, with immaterial losses beyond that date. Substantially all of Pepco Energy Services' retail customer obligations will be fully performed by June 1, 2014.

In connection with the operation of the retail energy supply business, as of September 30, 2012 and December 31, 2011, Pepco Energy Services had net collateral pledged to counterparties, primarily in connection with the instruments it uses to hedge commodity price risk, of approximately $39 million and $113 million, respectively. The collateral pledged as of September 30, 2012 included less than $1 million in the form of letters of credit and $38 million posted in cash. Pepco Energy Services does not expect to have any such collateral obligations beyond June 1, 2014.

Pepco Energy Services' remaining businesses will not be affected by the wind-down of the retail energy supply business.

Pepco Energy Services deactivated its Buzzard Point oil-fired generation facility on May 31, 2012, and its Benning Road oil-fired generation facility on June 30, 2012.

Other Non-Regulated

Through its subsidiary Potomac Capital Investment Corporation and its subsidiaries, PHI maintains a portfolio of cross-border energy lease investments with a book value at September 30, 2012 of approximately $1.2 billion. This activity comprises the "Other Non-Regulated" segment. For a 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.

Discontinued Operations

In April 2010, the Board of Directors approved a plan for the disposition of PHI's competitive wholesale power generation, marketing and supply business, which had been conducted through subsidiaries of Conectiv Energy Holding Company (collectively, Conectiv Energy). On July 1, 2010, PHI completed the sale of Conectiv Energy's wholesale power generation business to Calpine Corporation (Calpine) for $1.64 billion. The disposition of all of Conectiv Energy's remaining assets and businesses not included in the Calpine sale, including its load service supply contracts, energy hedging portfolio and certain tolling agreements, has been completed. The former operations of Conectiv Energy, which previously comprised a separate segment for financial reporting purposes, have been classified as a discontinued operation in PHI's consolidated financial statements, and the business is no longer treated as a separate segment for financial reporting purposes. Accordingly, in this Management's Discussion and Analysis of Financial Condition and Results of Operations, all references to continuing operations exclude the operations of the former Conectiv Energy segment.

Earnings Overview

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Net income from continuing operations for the three months ended September 30, 2012 was $112 million, or $0.49 per share, compared to $80 million, or $0.35 per share, for the three months ended September 30, 2011.

Net loss from discontinued operations for the three months ended September 30, 2011 was less than $1 million, or less than one cent per share.

Net income for the three months ended September 30, 2012 and 2011, by operating segment, is set forth in the table below (in millions of dollars):

	2012	2011	Change
Power Delivery	$ 92	$ 66	$ 26
Pepco Energy Services	5	8	(3)
Other Non-Regulated	16	5	11
Corporate and Other	(1)	1	(2)
Net Income from Continuing Operations	112	80	32
Discontinued Operations	—	—	—
Total PHI Net Income	$112	$ 80	$ 32

Discussion of Operating Segment Net Income Variances:

Power Delivery's $26 million increase in earnings was primarily due to the following:

- An increase of $10 million due to lower operation and maintenance expenses, primarily due to regulatory approval in 2012 for the establishment of regulatory assets for recovery of 2011 storm restoration costs and regulatory expenses.
- An increase of $9 million from electric distribution base rate increases (Pepco in Maryland, and DPL in Maryland and Delaware).
- An increase of $6 million due to higher distribution sales, primarily from customer growth and usage.
- An increase of $5 million primarily due to unfavorable income tax adjustments in 2011 related to a reallocation of deposits with the IRS with respect to tax liabilities in audit settlement years and subsequent years.
- An increase of $4 million from higher transmission revenue primarily attributable to higher rates effective June 1, 2012, related to increases in transmission plant investment.
- A decrease of $3 million due to higher interest expense resulting from an increase in outstanding debt.
- A decrease of $2 million associated with Default Electricity Supply margins for Pepco and DPL, primarily due to regulatory approvals by the respective public service commissions in the District of Columbia, Maryland and Delaware in 2011 of adjustments providing for recovery of higher cash working capital, administrative costs and miscellaneous taxes, partially offset by favorable Default Electricity Supply margin adjustments in 2012 related to the under-recognition of allowed revenues on procurement and transmission taxes in Delaware.

Pepco Energy Services' $3 million decrease in earnings was primarily due to lower energy services construction activity and the closure of its oil-fired generation facilities in the second quarter of 2012, partially offset by higher gross margins in the retail energy supply business attributable to mark-to-market accounting.

Other Non-Regulated's $11 million increase in earnings was primarily due to the gain on the early termination of certain cross-border energy leases.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Net income from continuing operations for the nine months ended September 30, 2012 was $242 million, or $1.06 per share, compared to $237 million, or $1.05 per share, for the nine months ended September 30, 2011.

Net income from discontinued operations for the nine months ended September 30, 2011 was $1 million, or less than one cent per share.

	2012	2011	Change
Power Delivery	$193	$185	$ 8
Pepco Energy Services	23	26	(3)
Other Non-Regulated	33	30	3
Corporate and Other	(7)	(4)	(3)
Net Income from Continuing Operations	242	237	5
Discontinued Operations	—	1	(1)
Total PHI Net Income	$242	$238	$ 4

Discussion of Operating Segment Net Income Variances:

Power Delivery's $8 million increase in earnings was primarily due to the following:

- An increase of $13 million from electric distribution base rate increases (Pepco in Maryland, and DPL in Maryland and Delaware) and the DPL gas distribution rate increase in Delaware.
- An increase of $12 million from higher transmission revenue, primarily attributable to higher rates effective June 1, 2012 and June 1, 2011, related to increases in transmission plant investment.
- An increase of $6 million primarily due to the net effect of income tax benefits resulting from changes in estimates and interest related to uncertain and effectively settled income tax positions.
- A decrease of $6 million due to higher operation and maintenance expenses, primarily associated with higher customer support service and system support costs and higher employee-related costs in 2012, and a reduction in self-insurance reserves in 2011, partially offset by regulatory approval in 2012 for the establishment of regulatory assets for recovery of 2011 storm restoration costs and regulatory expenses.
- A decrease of $6 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 Pepco and DPL, primarily due to regulatory approvals by the respective public service commissions in the District of Columbia, Maryland and Delaware in 2011 of adjustments providing for recovery of higher cash working capital, administrative costs and miscellaneous taxes, partially offset by favorable Default Electricity Supply margin adjustments in 2012 related to the under-recognition of allowed revenues on procurement and transmission taxes in Delaware.
- A decrease of $5 million from higher depreciation expense associated with increases in plant investment.

Pepco Energy Services' $3 million decrease in earnings was primarily due to lower energy services construction activity and the closure of its oil-fired generation facilities in the second quarter of 2012, partially offset by higher gross margins in the retail energy supply business attributable to mark-to-market accounting.

Other Non-Regulated's $3 million increase in earnings was primarily due to higher earnings associated with the portfolio of cross-border energy lease investments (including an increase of $6 million in year-over-year gains on early terminations of certain cross-border energy leases), partially offset by favorable income tax adjustments related to uncertain and effectively settled income tax positions in 2011.

Consolidated Results of Operations

The following results of operations discussion compares the three months ended September 30, 2012, to the three months ended September 30, 2011. 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:

	2012	2011	Change
Power Delivery	$1,335	$1,329	$ 6
Pepco Energy Services	131	317	(186)
Other Non-Regulated	13	7	6
Corporate and Other	(3)	(5)	2
Total Operating Revenue	$1,476	$1,648	$ (172)

Power Delivery Business

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

	2012	2011	Change
Regulated T&D Electric Revenue	$ 599	$ 549	$ 50
Default Electricity Supply Revenue	695	735	(40)
Other Electric Revenue	15	17	(2)
Total Electric Operating Revenue	1,309	1,301	8
Regulated Gas Revenue	18	17	1
Other Gas Revenue	8	11	(3)
Total Gas Operating Revenue	26	28	(2)
Total Power Delivery Operating Revenue	$1,335	$1,329	$ 6

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 a 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, 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

	2012	2011	Change
Regulated T&D Electric Revenue			
Residential	$ 239	$ 217	$ 22
Commercial and industrial	268	251	17
Transmission and other	92	81	11
Total Regulated T&D Electric Revenue	$ 599	$ 549	$ 50

	2012	2011	Change
Regulated T&D Electric Sales (Gigawatt hours (GWh))			
Residential	5,708	5,584	124
Commercial and industrial	8,605	8,687	(82)
Transmission and other	58	58	—
Total Regulated T&D Electric Sales	14,371	14,329	42

	2012	2011	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,644	1,634	10
Commercial and industrial	198	198	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,844	1,834	10

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, as follows:

- 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 $50 million primarily due to:

- An increase of $15 million due to distribution rate increases (Pepco in Maryland effective July 2012; DPL in Delaware and Maryland effective July 2012).
- An increase of $11 million in transmission revenue primarily attributable to higher rates effective June 1, 2012 related to increases in transmission plant investment and operating expenses.
- An increase of $8 million primarily due to a rate increase in the New Jersey Societal Benefit Charge (a surcharge to recover costs for various NJBPU-mandated societal programs) effective July 2012 (which is offset in Deferred Electric Service Costs and Other Operation and Maintenance).
- An increase of $7 million primarily due to a 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 $5 million due to EmPower Maryland (a demand side management program) rate increases in February 2012 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $3 million due to higher non-weather related average customer usage.
- An increase of $2 million due to Pepco customer growth in 2012, primarily in the residential class.

The aggregate amount of these increases was partially offset by a decrease of $3 million due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of lower sales that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the county.

Default Electricity Supply

	2012	2011	Change
Default Electricity Supply Revenue			
Residential	$499	$518	$ (19)
Commercial and industrial	160	175	(15)
Other	36	42	(6)
Total Default Electricity Supply Revenue	$695	$735	$ (40)

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.

	2012	2011	Change
Default Electricity Supply Sales (GWh)			
Residential	4,696	4,869	(173)
Commercial and industrial	1,547	1,700	(153)
Other	12	17	(5)
Total Default Electricity Supply Sales	6,255	6,586	(331)

	2012	2011	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,382	1,451	(69)
Commercial and industrial	130	139	(9)
Other	—	1	(1)
Total Default Electricity Supply Customers	1,512	1,591	(79)

Default Electricity Supply Revenue decreased by $40 million primarily due to:

- A decrease of $43 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $7 million in wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from NUGs.
- A net decrease of $5 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 $10 million due to higher non-weather related average customer usage.
- An increase of $3 million due to higher sales as a result of warmer weather during the 2012 summer months, as compared to 2011.

Total Default Electricity Supply Revenue for the three months ended September 30, 2012 includes a decrease of $2 million in unbilled revenue attributable to ACE's BGS ($1 million decrease in net income), primarily due to lower non-weather related average customer usage during the unbilled revenue period at September 30, 2012 as compared to the corresponding period in 2011. 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

	2012	2011	Change
Regulated Gas Revenue			
Residential	$10	$ 9	$ 1
Commercial and industrial	6	6	—
Transportation and other	2	2	—
Total Regulated Gas Revenue	$18	$17	$ 1

	2012	2011	Change
Regulated Gas Sales (million cubic feet)			
Residential	410	397	13
Commercial and industrial	389	374	15
Transportation and other	1,290	1,371	(81)
Total Regulated Gas Sales	2,089	2,142	(53)

	2012	2011	Change
Regulated Gas Customers (in thousands)			
Residential	115	114	1
Commercial and industrial	9	9	—
Transportation and other	—	—	—
Total Regulated Gas Customers	124	123	1

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, stand alone construction and tourism.
- Industrial activities in the region include chemical and pharmaceutical.

Regulated Gas Revenue increased by $1 million primarily due to higher non-weather related average customer usage.

Other Gas Revenue

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

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $186 million primarily due to:

- A decrease of $143 million due to lower retail supply sales volume primarily attributable to the ongoing wind-down of the retail energy supply business.
- A decrease of $37 million due to lower generation and capacity revenues attributable to the retirement of the remaining generation facilities in the second quarter of 2012.
- A decrease of $7 million due to lower construction activity in the energy services business.

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 was as follows:

	2012	2011	Change
Power Delivery	$646	$710	$ (64)
Pepco Energy Services	105	280	(175)
Corporate and Other	(4)	—	(4)
Total	$747	$990	$ (243)

Power Delivery Business

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 $64 million primarily due to:

- A decrease of $51 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $30 million primarily due to customer migration to competitive suppliers.
- A decrease of $3 million in the cost of gas purchases for on-system sales primarily as a result of lower average gas prices and lower volumes purchased.
- A decrease of $3 million in the cost of gas purchases for off-system sales as a result of lower average gas prices.
- A decrease of $3 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:

- An increase of $18 million in deferred electricity expense primarily due to lower Pepco and DPL Default Electricity Supply rates, which resulted in a higher rate of recovery of Default Electricity Supply costs.
- An increase of $6 million in deferred gas expense as a result of a higher rate of recovery of natural gas supply costs.
- An increase of $2 million due to higher electricity sales primarily as a result of warmer weather during the summer months of 2012, as compared to the corresponding period in 2011.

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales decreased by $175 million primarily due to:

- A decrease of $111 million due to lower volumes of electricity purchased to serve decreased retail electricity sales volumes as a result of the ongoing wind-down of the retail energy supply business.
- A decrease of $38 million due to lower volumes of gas purchased to serve decreased retail gas sales volumes as a result of the ongoing wind-down of the retail energy supply business.
- A decrease of $25 million due to lower purchases of capacity and lower fuel usage attributable to the retirement of the remaining generation facilities in the second quarter of 2012.
- A decrease of $2 million due to lower construction activity in the energy services business.

Other Operation and Maintenance

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

	2012	2011	Change
Power Delivery	$228	$243	$ (15)
Pepco Energy Services	16	21	(5)
Other Non-Regulated	1	1	—
Corporate and Other	(15)	(26)	11
Total	$230	$239	$ (9)

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $15 million primarily due to:

- A decrease of $10 million primarily due to a decrease in total incremental storm restoration costs for major storm events as described in the following table:

	2012	2011	Change
Regulatory asset established for future recovery of January 2011 winter storm costs	$ (9)	$—	$ (9)
Costs associated with derecho storm (June 2012)	38	—	38
Regulatory assets established for future recovery of derecho storm costs	(33)	—	(33)
Costs associated with Hurricane Irene (August 2011)	—	30	(30)
Regulatory assets established for future recovery of Hurricane Irene costs	—	(24)	24
Total incremental major storm restoration costs	$ (4)	$ 6	$ (10)

  - In July 2012, the MPSC issued an order allowing for the deferral and recovery of $9 million of incremental storm restoration costs incurred in connection with the January 2011 winter storm, which costs had previously been expensed in 2011.
  - In the third quarter of 2012, Pepco, DPL and ACE incurred incremental storm restoration costs of $38 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $33 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey, and will be pursuing recovery of these incremental storm restoration costs in their respective jurisdictions during the next cycle of electric distribution base rate cases. The remaining costs of $5 million primarily relate to repair work completed in Delaware and the District of Columbia which are not currently deferrable in those jurisdictions.
  - In the third quarter of 2011, Pepco, DPL and ACE incurred incremental storm restoration costs of $30 million associated with Hurricane Irene which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $24 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey. The MPSC approved the recovery of these costs in Maryland for both Pepco and DPL in its July 2012 rate orders. ACE's stipulation of settlement approved by the NJBPU in October 2012 provides for recovery of these costs in New Jersey. The remaining costs of $6 million relate to repair work completed in Delaware and the District of Columbia which are not currently deferrable in those jurisdictions.

- A decrease of $7 million associated with lower maintenance and tree trimming costs due to accelerated efforts made in 2011 to improve reliability.
- A decrease of $3 million due to the deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. These deferrals to a regulatory asset were recorded in accordance with the MPSC rate order issued in July 2012 and the DCPSC rate order issued in September 2012, each allowing for the recovery of these costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $2 million in New Jersey Societal Benefit Program costs that are deferred and recoverable.
- An increase of $2 million in system support costs.

<u>Pepco Energy Services</u>

Other Operation and Maintenance expense for Pepco Energy Services decreased by $5 million primarily due to the closing of the oil-fired generation facilities in the second quarter of 2012.

<u>Corporate and Other</u>

Other Operation and Maintenance expense for Corporate and Other increased by $11 million due to an increase in employee-related costs, primarily pension and other postretirement benefits, as well as reduced intercompany eliminations.

Depreciation and Amortization

Depreciation and Amortization expense increased by $7 million to $122 million in 2012 from $115 million in 2011 primarily due to:

- An increase of $7 million in amortization of regulatory assets primarily due to EmPower Maryland surcharge rate increases effective February 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $3 million in the Delaware Renewable Energy Portfolio Standards deferral associated with the over-recovery of renewable energy procurement costs (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $2 million in amortization of AMI project costs.

The aggregate amount of these increases was partially offset by a decrease of $5 million in amortization of stranded costs as the result of lower revenue due to rate decreases effective October 2011 for the ACE Transition Bond Charge and Market Transition Charge Tax (partially offset in Default Electricity Supply Revenue).

The MPSC reduced the depreciation rates for Pepco and DPL in their most recent electric distribution base rate cases, which is expected to lower annual Depreciation and Amortization expense for PHI by approximately $31 million effective July 20, 2012.

Other Taxes

Other Taxes decreased by $5 million to $121 million in 2012 from $126 million in 2011. 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).

Gain on Early Termination of Finance Leases Held in Trust

PHI's operating expenses include a $39 million pre-tax ($9 million after-tax) gain for the three months ended September 30, 2012 associated with the early termination of several leases included in its cross-border energy lease portfolio.

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 $46 million, to an expense of $29 million in 2012 as compared to an expense reduction of $17 million in 2011, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply revenue rates, partially offset by higher electricity supply costs.

Impairment Losses

PHI's operating expenses for the three months ended September 30, 2012, included impairment losses of $2 million pre-tax ($1 million after-tax) at Pepco Energy Services associated with a reduction in the estimated net realizable value of the combustion turbines at Buzzard Point.

Income Tax Expense

PHI's income tax expense increased by $38 million to $93 million in 2012 from $55 million in 2011. PHI's consolidated effective income tax rates for the three months ended September 30, 2012 and 2011 were 45.4% and 40.7%, respectively. The increase in the effective rate for the three months ended September 30, 2012 primarily reflects the reversal of income tax benefits associated with cross-border energy lease investments in the third quarter of 2012, partially offset by changes in estimates and interest related to uncertain and effectively settled tax positions recorded in 2011.

As discussed above, during the third quarter of 2012, PHI terminated early its interest in certain cross-border energy leases. As a result of the early terminations, PHI reversed $16 million of previously recognized income tax benefits which will not be realized due to the early termination. For additional information, see Note (8), "Leasing Activities," to the consolidated financial statements of PHI.

The following results of operations discussion compares the nine months ended September 30, 2012, to the nine months ended September 30, 2011. 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 was as follows:

	2012	2011	Change
Power Delivery	$3,374	$3,671	$ (297)
Pepco Energy Services	544	1,005	(461)
Other Non-Regulated	40	35	5
Corporate and Other	(11)	(13)	2
Total Operating Revenue	$3,947	$4,698	$ (751)

Power Delivery Business

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

	2012	2011	Change
Regulated T&D Electric Revenue	$1,523	$1,456	$ 67
Default Electricity Supply Revenue	1,681	1,996	(315)
Other Electric Revenue	46	50	(4)
Total Electric Operating Revenue	3,250	3,502	(252)
Regulated Gas Revenue	102	134	(32)
Other Gas Revenue	22	35	(13)
Total Gas Operating Revenue	124	169	(45)
Total Power Delivery Operating Revenue	$3,374	$3,671	$ (297)

Regulated T&D Electric

	2012	2011	Change
Regulated T&D Electric Revenue			
Residential	$ 555	$ 539	$ 16
Commercial and industrial	699	676	23
Transmission and other	269	241	28
Total Regulated T&D Electric Revenue	$ 1,523	$ 1,456	$ 67

	2012	2011	Change
Regulated T&D Electric Sales (GWh)			
Residential	13,474	14,214	(740)
Commercial and industrial	23,493	23,905	(412)
Transmission and other	183	181	2
Total Regulated T&D Electric Sales	37,150	38,300	(1,150)

	2012	2011	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,644	1,634	10
Commercial and industrial	198	198	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,844	1,834	10

Regulated T&D Electric Revenue increased by $67 million primarily due to:

- An increase of $27 million in transmission revenue primarily attributable to higher Pepco and DPL rates effective June 2012 and June 2011 related to increases in transmission plant investment and operating expenses.
- An increase of $21 million due to distribution rate increases (Pepco in Maryland effective July 2012; DPL in Maryland effective July 2012 and July 2011, and in Delaware effective July 2012).
- An increase of $12 million due to EmPower Maryland rate increases in February 2012 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $10 million primarily due to a 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 effective July 2012 (which is offset in Deferred Electric Service Costs and Other Operation and Maintenance).
- An increase of $6 million due to Pepco customer growth in 2012, primarily in the residential class.

The aggregate amount of these increases was partially offset by:

- A decrease of $11 million due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of lower sales that resulted in decreases in Montgomery County, Maryland and District of Columbia utility taxes that are collected by Pepco on behalf of the jurisdictions.
- A decrease of $6 million due to lower sales at DPL in Delaware and ACE as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A decrease of $3 million due to lower non-weather related average customer usage.

Default Electricity Supply

	2012	2011	Change
Default Electricity Supply Revenue			
Residential	$1,171	$1,363	$ (192)
Commercial and industrial	425	508	(83)
Other	85	125	(40)
Total Default Electricity Supply Revenue	$1,681	$1,996	$ (315)

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.

	2012	2011	Change
Default Electricity Supply Sales (GWh)			
Residential	11,256	12,568	(1,312)
Commercial and industrial	4,342	4,753	(411)
Other	41	54	(13)
Total Default Electricity Supply Sales	15,639	17,375	(1,736)

	2012	2011	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,382	1,451	(69)
Commercial and industrial	130	139	(9)
Other	—	1	(1)
Total Default Electricity Supply Customers	1,512	1,591	(79)

Default Electricity Supply Revenue decreased by $315 million primarily due to:

- A decrease of $108 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A net decrease of $93 million as a result of lower Pepco and DPL Default Electricity Supply rates, partially offset by higher ACE rates.
- A decrease of $49 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A decrease of $41 million in wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from NUGs.
- A decrease of $25 million due to lower non-weather related average customer usage.
- A decrease of $3 million resulting from the recognition in March 2011 of $3 million of DCPSC-approved revenues for the recovery of retroactive cash working capital costs incurred by Pepco in prior periods.

The aggregate amount of these decreases was partially offset by an increase of $3 million due to higher revenue from transmission enhancement credits.

Total Default Electricity Supply Revenue for the nine months ended September 30, 2012 includes a decrease of $2 million in unbilled revenue attributable to ACE's BGS ($1 million decrease in net income), primarily due to lower weather-related average customer usage during the unbilled revenue period at September 30, 2012 as compared to the corresponding period in 2011. 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

	2012	2011	Change
Regulated Gas Revenue			
Residential	$ 63	$ 82	$ (19)
Commercial and industrial	32	45	(13)
Transportation and other	7	7	—
Total Regulated Gas Revenue	$ 102	$ 134	$ (32)

	2012	2011	Change
Regulated Gas Sales (million cubic feet)			
Residential	4,052	5,338	(1,286)
Commercial and industrial	2,310	3,207	(897)
Transportation and other	4,877	5,210	(333)
Total Regulated Gas Sales	11,239	13,755	(2,516)

	2012	2011	Change
Regulated Gas Customers (in thousands)			
Residential	115	114	1
Commercial and industrial	9	9	—
Transportation and other	—	—	—
Total Regulated Gas Customers	124	123	1

Regulated Gas Revenue decreased by $32 million primarily due to:

- A decrease of $17 million due to lower sales primarily as a result of milder weather during the winter months of 2012 as compared to 2011.
- A decrease of $10 million due to lower non-weather related average customer usage.
- A decrease 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).
- A decrease of $2 million due to a Gas Cost Rate (GCR) decrease effective November 2011.

The aggregate amount of these decreases was partially offset by an increase of $1 million due to a distribution rate increase effective July 2011.

Other Gas Revenue

Other Gas Revenue decreased by $13 million primarily due to lower average prices and lower volumes for off-system sales to electric generators and gas marketers.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $461 million primarily due to:

- A decrease of $409 million due to lower retail supply sales volume primarily attributable to the ongoing wind-down of the retail energy supply business.
- A decrease of $47 million due to lower generation and capacity revenues attributable to the retirement of the remaining generation facilities in the second quarter of 2012.
- A decrease of $6 million due to decreased energy services construction activities.

Operating Expenses

Fuel and Purchased Energy and Other Services Cost of Sales

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

	2012	2011	Change
Power Delivery	$1,647	$2,000	$ (353)
Pepco Energy Services	436	887	(451)
Corporate and Other	(3)	—	(3)
Total	$2,080	$2,887	$ (807)

Power Delivery Business

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 $353 million primarily due to:

- A decrease of $165 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $110 million primarily due to customer migration to competitive suppliers.
- A decrease of $43 million due to lower electricity sales primarily as a result of milder weather during the winter and spring months of 2012, as compared to the corresponding periods in 2011.
- A decrease of $21 million in the cost of gas purchases for on-system sales as a result of lower average gas prices and lower volumes purchased.
- A decrease of $11 million in the cost of gas purchases for off-system sales as a result of lower average gas prices and lower volumes purchased.
- A decrease of $6 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.
- A decrease of $4 million in deferred electricity expense resulting from an adjustment recorded by DPL in June 2012 related to the under-recognition of allowed revenues on Default Electricity Supply procurement and transmission taxes in Delaware.
- A decrease 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 a decrease in Regulated Gas Revenue).

The aggregate amount of these decreases was partially offset by:

- An increase of $5 million in deferred gas expense as a result of higher rate of recovery of natural gas supply costs.
- An increase of $4 million in deferred electricity expense primarily due to lower DPL Default Electricity Supply rates, which resulted in a higher 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 $451 million primarily due to:

- A decrease of $289 million due to lower volumes of electricity purchased to serve decreased retail electricity sales volumes as a result of the ongoing wind-down of the retail energy supply business.
- A decrease of $142 million due to lower volumes of gas purchased to serve decreased retail gas sales volumes as a result of the ongoing wind-down of the retail energy supply business.
- A decrease of $27 million due to lower purchases of capacity, as well as lower fuel usage attributable to the retirement of the remaining generation facilities in the second quarter of 2012.

The aggregate amount of these decreases was partially offset by an increase of $6 million due to higher costs for energy services construction activities.

Other Operation and Maintenance

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

	2012	2011	Change
Power Delivery	$671	$662	$ 9
Pepco Energy Services	53	63	(10)
Other Non-Regulated	3	3	—
Corporate and Other	(48)	(46)	(2)
Total	$679	$682	$ (3)

Power Delivery

Other Operation and Maintenance expense for Power Delivery increased by $9 million primarily due to:

- An increase of $12 million in customer support service and system support costs.
- An increase of $12 million in employee-related costs, primarily pension and other employee benefits.
- An increase of $4 million in New Jersey Societal Benefit Program costs that are deferred and recoverable.
- An increase of $4 million resulting from a decrease in deferred cost adjustments associated with DPL Default Electricity Supply. The deferred costs adjustments were primarily due to the under-recognition of allowed returns on working capital in 2011 and allowed returns on net uncollectible expense and regulatory taxes in 2012.

- An increase of $4 million in expenses related to regulatory filings.
- An increase of $3 million primarily due to a 2011 reduction in self-insurance reserves for general and auto liability claims.
- An increase of $2 million in communication costs.

The aggregate amount of these increases was partially offset by:

- A decrease of $20 million primarily due to a decrease in total incremental storm restoration costs for major storm events as described in the following table:

	2012	2011	Change
Costs associated with severe winter storm (January 2011)	$—	$ 10	$ (10)
Regulatory asset established for future recovery of January 2011 winter storm costs	(9)	—	(9)
Costs associated with derecho storm (June 2012)	40	—	40
Regulatory asset established for future recovery of derecho storm costs	(35)	—	(35)
Costs associated with Hurricane Irene (August 2011)	—	30	(30)
Regulatory asset established for future recovery of Hurricane Irene costs	—	(24)	24
Total incremental major storm restoration costs	$ (4)	$ 16	$ (20)

  - In January 2011, Pepco incurred incremental storm restoration costs of $10 million associated with a severe winter storm, all of which were expensed in 2011. In July 2012, the MPSC issued an order allowing for the deferral and recovery of $9 million of such costs.
  - In the second and third quarters of 2012, Pepco, DPL and ACE incurred incremental storm restoration costs of $40 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $35 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey, and will be pursuing recovery of these incremental storm restoration costs in their respective jurisdictions during the next cycle of electric distribution base rate cases. The remaining costs of $5 million primarily relate to repair work completed in Delaware and the District of Columbia which are not currently deferrable in those jurisdictions.
  - In the third quarter of 2011, Pepco, DPL and ACE incurred incremental storm restoration costs of $30 million associated with Hurricane Irene which also resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $24 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey. The MPSC approved the recovery of these costs in Maryland for both Pepco and DPL in its July 2012 rate orders. ACE's stipulation of settlement approved by the NJBPU in October 2012 provides for recovery of these costs in New Jersey. The remaining costs of $6 million relate to repair work completed in Delaware and the District of Columbia which are not currently deferrable in those jurisdictions.
- A decrease of $5 million in bad debt expenses.
- A decrease of $4 million in other storm restoration costs.
- A decrease of $3 million due to the deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. These deferrals were recorded in accordance with the MPSC rate order issued in July 2012 and the DCPSC rate order issued in September 2012, each allowing for the recovery of these costs.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $10 million primarily due to the closing of the oil-fired generation facilities in the second quarter of 2012.

Depreciation and Amortization

Depreciation and Amortization expense increased by $18 million to $343 million in 2012 from $325 million in 2011 primarily due to:

- An increase of $13 million in amortization of regulatory assets primarily due to EmPower Maryland surcharge rate increases effective February 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $8 million due to utility plant additions, partially offset by lower depreciation rates.
- An increase of $6 million in amortization of AMI project costs.
- An increase of $4 million in the Delaware Renewable Energy Portfolio Standards deferral associated with the over-recovery of renewable energy procurement costs (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 $16 million in amortization of stranded costs as the result of lower revenue due to rate decreases effective October 2011 for the ACE Transition Bond Charge and Market Transition Charge Tax (partially offset in Default Electricity Supply Revenue).

The MPSC reduced the depreciation rates for Pepco and DPL in their most recent electric distribution base rate cases, which is expected to lower annual Depreciation and Amortization expense for PHI by approximately $31 million effective July 20, 2012.

Other Taxes

Other Taxes decreased by $16 million to $330 million in 2012 from $346 million in 2011. The decrease was primarily due to:

- A decrease of $9 million, 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).
- A decrease of $4 million in ACE Transitional Energy Facility Assessment taxes due to a rate decrease effective January 2012 (partially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Gain on Early Termination of Finance Leases Held in Trust

PHI’s operating expenses include a $39 million pre-tax gain for each of the nine months ended September 30, 2012 and 2011, associated with the early termination of several leases included in its cross-border energy lease portfolio. The after-tax gains were $9 million and $3 million for the nine months ended September 30, 2012 and 2011, respectively.

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 $43 million, to an expense reduction of $6 million in 2012 as compared to an expense reduction of $49 million in 2011, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply revenue rates, partially offset by higher electricity supply costs.

Impairment Losses

PHI's operating expenses for the nine months ended September 30, 2012, included impairment losses of $5 million pre-tax ($3 million after-tax) at Pepco Energy Services associated primarily with a reduction in the estimated net realizable value of the combustion turbines at Buzzard Point and the investment in a landfill gas-fired electric generation facility. During the second quarter, Pepco Energy Services performed a long-lived asset impairment test on the landfill generation facility as a result of a sustained decline in energy prices, and the asset value of 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 $5 million to a net expense of $171 million in 2012 from a net expense of $166 million in 2011. The increase reflects a $9 million increase in interest expense primarily associated with higher long-term debt and lower capitalized interest. The increase was partially offset by an increase of $4 million in other income primarily due to 2011 losses on equity investments.

<u>Income Tax Expense</u>

PHI's income tax expense decreased by $1 million to $142 million in 2012 from $143 million in 2011. PHI's consolidated effective income tax rates for the nine months ended September 30, 2012 and 2011 were 37.0% and 37.6%, respectively. The effective income tax rates for the nine months ended September 30, 2012 and 2011 reflect the reversal of income tax benefits associated with the early termination of cross-border energy leases in the third quarter of 2012 and in the second quarter of 2011 of $16 million and $22 million, respectively, as discussed in Note (8), "Leasing Activities."

In addition, the effective income tax rate for the nine months ended September 30, 2012 includes income tax benefits of $10 million 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. During the nine months ended September 30, 2011, PHI recorded tax benefits of $11 million related to uncertain and effectively settled tax positions, primarily resulting from the settlement with the IRS on interest due on its 1996 through 2002 tax years.

The rate for the nine months ended September 30, 2012 also reflects an increase in deductible asset removal costs for Pepco in 2012 related to a higher level of asset retirements.

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 September 30, 2012, PHI's current assets on a consolidated basis totaled $1.5 billion and its consolidated current liabilities totaled $2.0 billion, resulting in a working capital deficit of $516 million. PHI expects the working capital deficit at September 30, 2012 to be funded during the remainder of 2012 through cash flows from operations. Additional working capital will be provided by anticipated reductions in collateral requirements due to the ongoing wind-down of the Pepco Energy Services retail energy supply business. At December 31, 2011, PHI's current assets on a consolidated basis totaled $1.4 billion and its current liabilities totaled $1.9 billion, for a working capital deficit of $422 million. The increase of $94 million in the working capital deficit from December 31, 2011 to September 30, 2012 was primarily due to an increase in short-term debt for PHI, Pepco and ACE to temporarily support higher spending by the utilities on infrastructure investments and reliability initiatives.

At September 30, 2012, PHI's consolidated cash and cash equivalents totaled $114 million, of which $100 million was invested in money market funds, and the balance was held as cash and uncollected funds. Current Restricted Cash Equivalents (cash that is available to be used only for designated purposes) totaled $14 million. At December 31, 2011, PHI's consolidated cash and cash equivalents totaled $109 million, of which $87 million was invested in money market funds, and the balance was held as cash and uncollected funds. At December 31, 2011, PHI's current Restricted Cash Equivalents totaled $11 million.

A detail of PHI's short-term debt balance and current portion of long-term debt and project funding balance was as follows:

	As of September 30, 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	293	134	—	93	—	—	520
Term Loan Agreement	200	—	—	—	—	—	200
Total Short-Term Debt	$ 493	$134	$105	$116	$ —	$ —	$ 848
Current Portion of Long-Term Debt and Project Funding	$—	$—	$—	$ 69	$ 39	$ 10	$ 118

Type	As of December 31, 2011 (millions of dollars) PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PHI Consolidated
Variable Rate Demand Bonds	$—	$—	$105	$ 23	$ —	$ 18	$ 146
Commercial Paper	465	74	47	—	—	—	586
Total Short-Term Debt	$ 465	$ 74	$152	$ 23	$ —	$ 18	$ 732
Current Portion of Long-Term Debt and Project Funding	$—	$—	$ 66	$—	$ 37	$ 9	$ 112

Commercial Paper

PHI, Pepco, DPL and ACE maintain commercial paper programs to address short-term liquidity needs. As of September 30, 2012, 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, Pepco and ACE had $293 million, $134 million and $93 million, respectively, of commercial paper outstanding at September 30, 2012. DPL had no commercial paper outstanding at September 30, 2012. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2012 was 0.87%, 0.42%, 0.43% and 0.42%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2012 was ten, four, four and three days, respectively.

Equity Forward Transaction

On March 5, 2012, PHI entered into an equity forward transaction in connection with a public offering of 17,922,077 shares of PHI common stock. The use of an equity forward transaction substantially eliminates future equity market price risk by fixing a common equity offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until funds are needed in accordance with PHI's capital investment and regulatory plans.

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, to the extent that the transaction is physically settled, PHI would be 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 the amount of cash to be received by PHI upon physical settlement of the equity forward is subject to certain adjustments in accordance with the terms of the equity forward transaction. The equity forward transaction must be settled fully within 12 months of the transaction date. Except in specified circumstances or events that would require physical settlement, PHI is able to elect to settle the equity forward transaction by means of physical, cash or net share settlement, in whole or in part, at any time on or prior to March 5, 2013.

The equity forward transaction had no initial fair value since it was entered into at the then market price of the common stock. PHI will not receive any proceeds from the sale of common stock until the equity forward transaction is settled, and at that time PHI will record the proceeds, if any, in equity. PHI concluded that the equity forward transaction was an equity instrument based on the accounting guidance in Accounting Standards Codification (ASC) 480 and ASC 815 and that it qualified for an exception from derivative accounting under ASC 815 because the forward sale transaction was indexed to its own stock. PHI anticipates settling the equity forward transaction through physical settlement before March 5, 2013.

At September 30, 2012, the equity forward transaction could have been settled with physical delivery of the shares to the forward counterparty in exchange for cash of $317 million. At September 30, 2012, the equity forward transaction could also have been cash settled, with delivery of cash of approximately $18 million to the forward counterparty, or net share settled with delivery of approximately 965,000 shares of common stock to the forward counterparty.

Prior to its settlement, the equity forward transaction will be reflected in PHI's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PHI's common stock used in calculating diluted earnings per share for a reporting period would be increased by the number of shares, if any, that would be issued upon physical settlement of the equity forward transaction less the number of shares that could be purchased by PHI in the market (based on the average market price during that reporting period) using the proceeds receivable upon settlement of the equity forward transaction (based on the adjusted forward sale price at the end of that reporting period). The excess number of shares is weighted for the portion of the reporting period in which the equity forward transaction is outstanding.

Accordingly, before physical or net share settlement of the equity forward transaction, and subject to the occurrence of certain events, PHI anticipates that the forward sale agreement will have a dilutive effect on PHI's earnings per share only during periods when the applicable average market price per share of PHI's common stock is above the per share adjusted forward sale price, as described above. However, if PHI decides to physically or net share settle the forward sale agreement, any delivery by PHI of shares upon settlement could result in dilution to PHI's earnings per share.

For the three and nine months ended September 30, 2012, the equity forward transaction did not have a material dilutive effect on PHI's earnings per share.

Financing Activity During the Three Months Ended September 30, 2012

Bond Redemptions

On August 6, 2012, DPL redeemed, prior to maturity, $31 million of its 5.20% tax-exempt pollution control refunding revenue bonds due 2019, issued by the Delaware Economic Development Authority for DPL's benefit. Contemporaneously with this redemption, DPL redeemed $31 million of its outstanding 5.20% first mortgage bonds due 2019 that secured the obligations under the pollution control bonds.

On September 28, 2012, ACE redeemed, prior to maturity, $4 million of its 5.60% tax-exempt pollution control revenue bonds due 2025 issued by the Industrial Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit. Contemporaneously with this redemption, ACE redeemed, prior to maturity, $4 million of its outstanding 5.60% first mortgage bonds due 2025 that secured the obligations under the pollution control bonds.

Bond Payments

In July 2012, ACE Funding made principal payments of $6 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

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 among other changes, extended the expiration date of the facility to August 1, 2016. On August 2, 2012, the amended and restated credit agreement 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.

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 initial credit sublimit for PHI is $750 million 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.

For additional discussion of the Credit Facility, see Note (10), "Debt," to the consolidated financial statements of PHI.

Term Loan Agreement

On April 24, 2012, PHI entered into a $200 million term loan agreement, pursuant to which PHI has borrowed (and may not reborrow) $200 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the London Interbank Offered Rate 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 borrowings under the term loan agreement to repay outstanding commercial paper obligations and for general corporate purposes. For additional discussion of the Term Loan Agreement, see Note (10), "Debt," to the consolidated financial statements of PHI.

Cash and Credit Facility Available as of September 30, 2012

	Consolidated PHI	PHI Parent	Utility Subsidiaries
		(millions of dollars)	
Credit Facility (Total Capacity)	$ 1,500	$ 750	$ 750
Term Loan Agreement	200	200	—
Subtotal	1,700	950	750
Less: Credit Facility/Term Loan Agreement Borrowings	200	200	—
Letters of Credit issued	2	2	—
Commercial Paper outstanding	520	293	227
Remaining Credit Facility Available	978	455	523
Cash Invested in Money Market Funds (a)	100	60	40
Total Cash and Credit Facility Available	$ 1,078	$ 515	$ 563

(a) Cash and cash equivalents reported on the PHI consolidated balance sheet total $114 million, of which $100 million was invested in money market funds, and the balance was held in cash and uncollected funds.

Collateral Requirements of Pepco Energy Services

In the ordinary course of its retail energy supply business which is in the process of winding down, Pepco Energy Services entered into various contracts to buy and sell electricity, fuels and related products, including derivative instruments, designed to reduce its financial exposure to changes in the value of its assets and obligations due to energy price fluctuations. These contracts typically have collateral requirements. Depending on the contract terms, the collateral required to be posted by Pepco Energy Services can be of varying forms, including cash and letters of credit. As of September 30, 2012, Pepco Energy Services posted net cash collateral of $38 million and letters of credit of less than $1 million. At December 31, 2011, Pepco Energy Services posted net cash collateral of $112 million and letters of credit of $1 million.

At September 30, 2012 and December 31, 2011, the amount of cash, plus borrowing capacity under PHI's unsecured credit facility available to meet the future liquidity needs of Pepco Energy Services, totaled $515 million and $283 million, respectively.

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 2011, 2010 and 2009. On January 31, 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.

Based on the results of the 2011 actuarial valuation, PHI's net periodic pension and other postretirement benefit costs were approximately $94 million in 2011 versus $116 million in 2010. The current estimate of benefit cost for 2012 is $111 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 $78 million in 2012, as compared to $66 million in 2011 and $81 million in 2010.

Cash Flow Activity

PHI's cash flows for the nine months ended September 30, 2012 and 2011 are summarized below:

	Cash Source (Use)		
	2012	2011	Change
		(millions of dollars)	
Operating Activities	$ 419	$ 531	$ (112)
Investing Activities	(662)	(471)	(191)
Financing Activities	248	22	226
Net increase in cash and cash equivalents	$ 5	$ 82	$ (77)

Operating Activities

Cash flows from operating activities during the nine months ended September 30, 2012 and 2011 are summarized below:

	Cash Source (Use)		
	2012	2011	Change
		(millions of dollars)	
Net income from continuing operations	$ 242	$ 237	$ 5
Non-cash adjustments to net income	298	281	17
Gain on early termination of finance leases held in trust	(39)	(39)	—
Pension contributions	(200)	(110)	(90)
Changes in cash collateral related to derivative activities	76	5	71
Changes in other assets and liabilities	42	113	(71)
Changes in Conectiv Energy net assets held for sale	—	44	(44)
Net cash from operating activities	$ 419	$ 531	$ (112)

Net cash from operating activities decreased $112 million for the nine months ended September 30, 2012, compared to the same period in 2011. The decrease was due primarily to a $90 million increase in pension contributions compared to 2011 and the disposition of substantially all of Conectiv Energy's remaining assets in 2011.

Investing Activities

Cash flows from investing activities during the nine months ended September 30, 2012 and 2011 are summarized below:

	Cash Source (Use)		
	2012	2011	Change
		(millions of dollars)	
Investment in property, plant and equipment	$(888)	$(639)	$ (249)
Department of Energy (DOE) capital reimbursement awards received	25	27	(2)
Proceeds from early termination of finance leases held in trust	202	161	41
Changes in restricted cash equivalents	(2)	(10)	8
Net other investing activities	1	(10)	11
Net cash used by investing activities	$(662)	$(471)	$ (191)

Net cash used by investing activities increased $191 million for the nine months ended September 30, 2012, compared to the same period in 2011. The increase was due primarily to a $249 million increase in capital expenditures associated with new customer services, distribution reliability and transmission. This increase was partially offset by $41 million in increased proceeds received from the early termination of certain cross-border energy leases.

Financing Activities

Cash flows from financing activities during the nine months ended September 30, 2012 and 2011 are summarized below:

	Cash Source (Use)		
	2012	2011	Change
	(millions of dollars)		
Dividends paid on common stock	$(185)	$(183)	$ (2)
Common stock issued for the Dividend Reinvestment Plan and employee-related compensation	40	36	4
Redemption of preferred stock of subsidiaries	—	(6)	6
Issuances of long-term debt	450	235	215
Reacquisitions of long-term debt	(165)	(60)	(105)
Issuances of short-term debt, net	116	11	105
Cost of issuances	(8)	(10)	2
Net other financing activities	—	(1)	1
Net cash from financing activities	$ 248	$ 22	$ 226

Net cash from financing activities increased $226 million for the nine months ended September 30, 2012 compared to the same period in 2011. The increase was due primarily to a $105 million increase in net short-term debt issuances to temporarily support higher spending by the utilities on infrastructure investments and reliability initiatives, and a $110 million net increase in long-term debt.

Redemption of Preferred Stock

On February 25, 2011, ACE redeemed all of its outstanding cumulative preferred stock for approximately $6 million.

Changes in Outstanding Long-Term Debt

The issuances and reacquisitions of long-term debt for the nine months ended September 30, 2012 and 2011 are summarized below:

	2012	2011
Issuances	(millions of dollars)	
Pepco		
3.05% First mortgage bonds due 2022	$ 200	$ —
	200	—
DPL		
0.75% Tax-exempt bonds due 2026 (a)	—	35
4.00% First mortgage bonds due 2042	250	—
	250	35
ACE		
4.35% First mortgage bonds due 2021	—	200
	—	200
	$ 450	$ 235

(a) Consists of Pollution Control Refunding Revenue Bonds (DPL Bonds) issued by the Delaware Economic Development Authority for the benefit of DPL that were purchased by DPL in May 2011. See footnote (b) to the Reacquisitions table below. The DPL Bonds were resold to the public in June 2011. While DPL held the DPL Bonds, they remained outstanding as a contractual matter, but were considered extinguished for accounting purposes. In connection with the resale of the DPL Bonds, the interest rate on the bonds was changed from 4.90% to a fixed rate of 0.75%.

Reacquisitions		2012	2011
		(millions of dollars)	
Pepco			
	5.375% Tax-exempt bonds due 2024 (a)	$ 38	$ —
		38	—
DPL			
	4.90% Tax-exempt bonds due 2026 (b)	—	35
	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	—
	5.20% Tax-exempt bonds due 2019	31	—
		97	35
ACE			
	Securitization bonds due 2011-2012	26	25
	5.60% Tax-exempt bonds due 2025(a)	4	—
		30	25
		$ 165	$ 60

(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.

(b) Repurchased by DPL in May 2011 pursuant to a mandatory purchase provision in the indenture for the bonds that was triggered by the expiration of the original interest period for the bonds. The bonds were resold by DPL in June 2011. See footnote (a) to the Issuances table above.

Changes in Short-Term Debt

As of September 30, 2012, PHI had a total of $520 million of commercial paper outstanding as compared to $586 million of commercial paper outstanding as of December 31, 2011.

Capital Requirements

Capital Expenditures

Pepco Holdings' capital expenditures for the nine months ended September 30, 2012 were $888 million, of which $449 million was incurred by Pepco, $219 million was incurred by DPL, $186 million was incurred by ACE, $11 million was incurred by Pepco Energy Services and $23 million was incurred 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. PHI currently anticipates that its total 2012 capital expenditures will approximate its original projections of $1,143 million.

PHI's projected capital expenditures for the Power Delivery business for the five-year period from 2013 through 2017, reflecting changes due to the termination of the MAPP project, are summarized below. For an additional discussion of the termination of the MAPP project, see "General Overview – Termination of the MAPP Project" above. PHI expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2013	2014	2015	2016	2017	Total
			(millions of dollars)			
Power Delivery						
Distribution	$ 733	$ 801	$ 784	$ 753	$ 730	$3,801
Distribution – Blueprint for the Future	41	1	—	8	45	95
Transmission	266	254	280	242	298	1,340
Gas Delivery	26	28	28	28	30	140
Other	139	126	102	80	83	530
Sub-Total	1,205	1,210	1,194	1,111	1,186	5,906
DOE Capital Reimbursement Awards (a)	(7)	—	—	—	—	(7)
Total for Power Delivery Business	$1,198	$1,210	$1,194	$1,111	$1,186	$5,899

(a) Reflects remaining anticipated reimbursements pursuant to awards from the DOE under the American Recovery and Reinvestment Act of 2009.

MAPP/DOE Loan Program

To assist in the funding of the MAPP project, PHI had applied for a $684 million loan guarantee from the DOE for a substantial portion of the MAPP project, primarily the Calvert Cliffs to Indian River segment. With the termination of the MAPP project, PHI intends to withdraw its application for the loan guarantee.

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.

In April 2010, Pepco, ACE and the DOE signed agreements formalizing the $168 million in awards. Of the $168 million, $130 million is being used for Blueprint for the Future 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 nine months ended September 30, 2012, Pepco and ACE received award payments of $30 million and $4 million, respectively. The cumulative award payments received by Pepco and ACE as of September 30, 2012, were $97 million and $12 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 October 25, 2012, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable December 31, 2012 to stockholders of record on December 10, 2012. PHI had approximately $1,129 million and $1,072 million of retained earnings free of restrictions at September 30, 2012 and December 31, 2011, respectively.

Energy Contract Net Asset Activity

The following table provides detail on changes in the net asset or liability positions of the Pepco Energy Services segment with respect to energy commodity contracts for the nine months ended September 30, 2012. The balances in the table are pre-tax and the derivative assets and liabilities reflect netting by the counterparty before the impact of collateral.

	Energy Commodity Activities (a)
	(millions of dollars)
Total Fair Value of Energy Contract Net Liabilities at December 31, 2011	$ (83)
Current period unrealized mark-to-market losses	(2)
Effective portion of changes in fair value – recorded in Accumulated Other Comprehensive Loss	—
Cash flow hedge ineffectiveness – recorded in income	—
Reclassification of mark-to-market losses to realized on settlement of contracts	53
Total Fair Value of Energy Contract Net Liabilities at September 30, 2012	$ (32)
Detail of Fair Value of Energy Contract Net Liabilities at September 30, 2012 (see above)	
Derivative assets (current assets)	$ 2
Derivative assets (non-current assets)	—
Total Fair Value of Energy Contract Assets	2
Derivative liabilities (current liabilities)	(33)
Derivative liabilities (non-current liabilities)	(1)
Total Fair Value of Energy Contract Liabilities	(34)
Total Fair Value of Energy Contract Net Liabilities	$ (32)

(a) Includes all effective hedging activities from continuing operations recorded at fair value through Accumulated Other Comprehensive Loss (AOCL) or trading activities from continuing operations recorded at fair value in the consolidated statements of income.

The $32 million net liability on energy contracts at September 30, 2012 was primarily attributable to losses on power swaps and natural gas futures held by Pepco Energy Services. The decrease from $83 million at December 31, 2011 is primarily due to the reclassification of mark-to-market losses to realized losses on settled derivatives. PHI expects that future revenues from existing customer sales obligations that are accounted for on an accrual basis will largely offset expected realized net losses on Pepco Energy Services' energy contracts.

PHI uses its best estimates to determine the fair value of the commodity derivative contracts that are entered into by Pepco Energy Services. The fair values in each category presented below reflect forward prices and volatility factors as of September 30, 2012, and the fair values are subject to change as a result of changes in these prices and factors.

Source of Fair Value	Fair Value of Contracts at September 30, 2012 Maturities 2012	2013	2014	2015 and Beyond	Total Fair Value
	(millions of dollars)				
Energy Commodity Activities, net (a)					
Actively Quoted (i.e., exchange-traded) prices	$ (7)	$ (9)	$ (2)	$ —	$ (18)
Prices provided by other external sources (b)	(5)	(8)	—	—	(13)
Modeled (c)	(1)	—	—	—	(1)
Total	$ (13)	$ (17)	$ (2)	$ —	$ (32)

(a) Includes all effective hedging activities recorded at fair value through AOCL, and hedge ineffectiveness and trading activities on the consolidated statements of income.

(b) Prices provided by other external sources reflect information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms that are readily observable in the market.

(c) Modeled values include significant inputs, usually representing more than 10% of the valuation, not readily observable in the market. The modeled valuation above represents the fair valuation of certain long-dated power transactions based on limited observable broker prices extrapolated for periods beyond two years into the future.

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 September 30, 2012, 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 $162 million, none of which is related to discontinued operations of Conectiv Energy. Of this amount, $56 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 $106 million is attributable primarily to energy services contracts and accounts payable to independent system operators and distribution companies on full requirements contracts entered into by Pepco Energy Services. 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 competitive energy and 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. As of September 30, 2012, Pepco Energy Services provided net cash collateral in the amount of $38 million in connection with these activities.

Regulatory and Other Matters

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether the electric distribution companies (EDCs) in Maryland 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 megawatt (MW) beginning in 2015. The order requires certain Maryland EDCs, including Pepco and DPL, 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 acknowledges certain of the EDCs' concerns about the requirements of the contract and directs them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specifies that the EDCs entering into the contract will recover the associated costs, in amounts proportional to their relative SOS loads, through surcharges on their respective SOS customers.

Until the final form of the contract with the winning bidder and associated cost recovery are approved, PHI cannot predict (i) the extent of the negative effect that the order and, once finalized, the contract for new generation, may have on PHI's, Pepco's and DPL's balance sheets, as well as their 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 order on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

On April 27, 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the Northern 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. On May 4, 2012, Pepco, DPL, and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These appeals have been consolidated in the Circuit Court for Baltimore City and are set for hearing on January 24, 2013.

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' 2011 Form 10-K. There have been no material changes to PHI's critical accounting policies as disclosed in Pepco Holdings' 2011 Form 10-K.

New Accounting Standards and Pronouncements

For information concerning new accounting standards and pronouncements that have recently been adopted by PHI and its subsidiaries or that one or more of the companies will be required to adopt on or before a specified date in the future, see Note (3), "Newly Adopted Accounting Standards," and Note (4), "Recently Issued Accounting Standards, Not Yet Adopted," to the consolidated financial statements of PHI.

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

Potomac Electric Power Company

Pepco meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

Pepco is engaged in the transmission and distribution of electricity in the District of Columbia and major portions of Prince George's County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply. Pepco's service territory covers approximately 640 square miles and has a population of approximately 2.2 million. As of September 30, 2012, 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 (such as 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 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 and Emergency Restoration Improvement Plans

In 2010, Pepco announced that it had adopted and begun to implement comprehensive reliability enhancement plans in Maryland and the District of Columbia. These reliability enhancement plans include various initiatives to improve electrical system reliability, such as:

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

In 2011, Pepco also initiated a program to improve its emergency restoration efforts that included, among other initiatives, an expansion and enhancement of customer service capabilities.

In 2012, Pepco has continued to focus on its reliability enhancement and emergency restoration improvement plans in each of its service territories.

Blueprint for the Future

Pepco is participating in a PHI initiative referred to as "Blueprint for the Future," which is designed to meet the challenges of rising energy costs, concerns about the environment, improved reliability and government energy reduction goals. For a discussion of the Blueprint for the Future initiative, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Blueprint for the Future."

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 most recent District of Columbia and Maryland base rate case filings 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 Pepco of fully forecasted test years in future base rate cases. See Note (6), "Regulatory Matters – Rate Proceedings," to the financial statements of Pepco for a discussion of each of these mechanisms. In its Pepco base rate case order, the MPSC did not approve 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, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases.

In Maryland, the governor forwarded to the MPSC a report issued by his Grid Resiliency Task Force (see Note (6), "Regulatory Matters – Maryland Governor's Grid Resiliency Task Force" to the financial statements of Pepco for additional discussion), urging the MPSC to quickly implement certain Task Force recommendations that would, among other things, accelerate reliability improvement investments and allow surcharge recovery for the accelerated investments. Pepco is currently evaluating the report and its recommendations to determine what effect, if any, they may have on proposals to be made in Pepco's future electric distribution base rate cases in Maryland to, among other things, mitigate the effects of regulatory lag. The form and substance of any such proposals will also depend, in part, on how the MPSC responds to the report and the governor's request.

Pepco will continue to seek cost recovery from the MPSC and the DCPSC 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 rate recovery mechanisms or base rate cases will fully mitigate the effects of regulatory lag. Until such time as any proposed or alternative mechanisms are approved, Pepco plans to file rate cases at least annually in an effort to align more closely the revenue and related cash flow levels of Pepco with its other operation and maintenance spending and capital investments. In light of the MPSC's decision in the most recent Pepco base rate case, Pepco intends to file its next electric distribution base rate case with the MPSC in the fourth quarter of 2012. Pepco also intends to file its next electric distribution base rate case with the DCPSC in the first quarter of 2013.

Termination of the MAPP Project

On August 24, 2012, the board of PJM notified PHI, on behalf of its subsidiaries Pepco and DPL, that the MAPP project has been terminated and removed from PJM's regional transmission expansion plan. PHI was originally 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 of PJM's decision, on October 2, 2012, Pepco filed with the MPSC a notice withdrawing its pending application related to the MAPP project. Pepco had included in its five-year projected capital expenditures $138 million of MAPP-related expenditures for the period from 2012 to 2016. Pepco has updated its five-year projected capital expenditures to remove the MAPP-related expenditures to reflect the PJM decision. See "Capital Requirements – Capital Expenditures" for a discussion of Pepco's projected capital expenditures.

As of September 30, 2012, Pepco's total capital expenditures for the MAPP project were approximately $64 million. Under the terms of the FERC order approving an incentive rate for the MAPP project, FERC authorized the recovery of abandoned costs prudently incurred in connection with the MAPP project. Consistent with this order, PHI intends to seek recovery of abandoned MAPP capital expenditures through a filing expected to be submitted to the FERC in the fourth quarter of 2012. The FERC filing is expected to address, among other things, the period over which the abandoned costs are to be recovered and the rate of return on these costs during the recovery period. Under an order issued by the FERC in 2008, Pepco is currently allowed to include its MAPP capital expenditures in its rate base, earning an incentive rate of return of 12.8% during the construction period.

As of September 30, 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, and reclassified the remaining $53 million of capital expenditures to a regulatory asset. 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 the regulatory asset by any amounts recovered from the sale or alternative use of the land, land rights, supplies and materials.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2012 to the nine months ended September 30, 2011. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

	2012	2011	Change
Regulated T&D Electric Revenue	$ 884	$ 854	$ 30
Default Electricity Supply Revenue	595	764	(169)
Other Electric Revenue	24	25	(1)
Total Operating Revenue	$1,503	$1,643	$ (140)

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

	2012	2011	Change
Regulated T&D Electric Revenue			
Residential	$261	$258	$ 3
Commercial and industrial	504	497	7
Transmission and other	119	99	20
Total Regulated T&D Electric Revenue	$884	$854	$ 30

	2012	2011	Change
Regulated T&D Electric Sales (GWh)			
Residential	6,072	6,446	(374)
Commercial and industrial	13,869	14,308	(439)
Transmission and other	113	113	—
Total Regulated T&D Electric Sales	20,054	20,867	(813)

	2012	2011	Change
Regulated T&D Electric Customers (in thousands)			
Residential	721	711	10
Commercial and industrial	74	74	—
Transmission and other	—	—	—
Total Regulated T&D Electric Customers	795	785	10

Regulated T&D Electric Revenue increased by $30 million primarily due to:

- An increase of $20 million in transmission revenue primarily attributable to higher rates effective June 1, 2012 and June 1, 2011 related to increases in transmission plant investment and operating expenses.
- An increase of $8 million due to an EmPower Maryland (a demand side management program) rate increase effective February 2012 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $7 million due to a distribution rate increase in Maryland effective July 2012.
- An increase of $6 million due to customer growth in 2012, primarily in the residential class.

The aggregate amount of these increases was partially offset by a decrease of $11 million due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of lower sales that resulted in decreases in Montgomery County, Maryland and District of Columbia utility taxes that are collected by Pepco on behalf of the jurisdictions.

Default Electricity Supply

	2012	2011	Change
Default Electricity Supply Revenue			
Residential	$ 426	$ 555	$ (129)
Commercial and industrial	161	203	(42)
Other	8	6	2
Total Default Electricity Supply Revenue	$ 595	$ 764	$ (169)

	2012	2011	Change
Default Electricity Supply Sales (GWh)			
Residential	4,797	5,493	(696)
Commercial and industrial	2,057	2,200	(143)
Other	5	6	(1)
Total Default Electricity Supply Sales	6,859	7,699	(840)

	2012	2011	Change
Default Electricity Supply Customers (in thousands)			
Residential	577	612	(35)
Commercial and industrial	44	46	(2)
Other	—	—	—
Total Default Electricity Supply Customers	621	658	(37)

Default Electricity Supply Revenue decreased by $169 million primarily due to:

- A decrease of $87 million as a result of lower Default Electricity Supply rates.
- A decrease of $45 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $22 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A decrease of $15 million due to lower non-weather related average customer usage.
- A decrease of $3 million resulting from the recognition in March 2011 of $3 million of DCPSC-approved revenues for the recovery of retroactive cash working capital costs incurred by Pepco in prior periods.

The aggregate amount of these decreases was partially offset by an increase of $3 million due higher revenue from transmission enhancement credits.

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 nine months ended September 30:

	2012	2011
Sales to District of Columbia customers	25%	27%
Sales to Maryland customers	41%	44%

<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 decreased by $159 million to $572 million in 2012 from $731 million in 2011 primarily due to:

- A decrease of $84 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $54 million primarily due to customer migration to competitive suppliers.

- A decrease of $19 million due to lower electricity sales primarily as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A decrease of $3 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 $12 million to $301 million in 2012 from $313 million in 2011 primarily due to:

- A decrease of $17 million primarily due to a decrease in total incremental storm restoration costs for major storm events as described in the following table:

	2012	2011	Change
Costs associated with severe winter storm (January 2011)	$—	$ 10	$ (10)
Regulatory asset established for future recovery of January 2011 winter storm costs	(9)	—	(9)
Costs associated with derecho storm (June 2012)	25	—	25
Regulatory asset established for future recovery of derecho storm costs	(21)	—	(21)
Costs associated with Hurricane Irene (August 2011)	—	14	(14)
Regulatory asset established for future recovery of Hurricane Irene costs	—	(12)	12
Total incremental major storm restoration costs	$ (5)	$ 12	$ (17)

  - In January 2011, Pepco incurred incremental storm restoration costs of $10 million associated with a severe winter storm, all of which were expensed in 2011. In July 2012, the MPSC issued an order allowing for the deferral and recovery of $9 million of such costs.
  - In the second and third quarters of 2012, Pepco incurred incremental storm restoration costs of $25 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of Pepco's service territories. Pepco deferred $21 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in Maryland and will be pursuing recovery of the incremental storm restoration costs in the District of Columbia during its next distribution base rate case in that jurisdiction. The remaining costs of $4 million primarily relate to repair work completed in the District of Columbia which are not currently deferrable.
  - In the third quarter of 2011, Pepco incurred incremental storm restoration costs of $14 million associated with Hurricane Irene which also resulted in widespread damage to the electric distribution system in each of Pepco's service territories. Pepco deferred $12 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in Maryland. The MPSC approved the recovery of these costs in Maryland for Pepco in its July 2012 rate order. The remaining costs of $2 million relate to repair work completed in the District of Columbia which are not currently deferrable.
- A decrease of $5 million in bad debt expenses.
- A decrease of $3 million due to the deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. These deferrals were recorded in accordance with the MPSC rate order issued in July 2012 and the DCPSC rate order issued in September 2012, each allowing for the recovery of these costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $5 million in employee-related-costs, primarily due to pension and other benefit expenses.

- An increase of $5 million in customer support service and system support costs.
- An increase of $2 million in expenses related to regulatory filings.
- An increase of $1 million due to 2011 reduction in self-insurance reserves for general and auto liability claims.

Depreciation and Amortization

Depreciation and Amortization expense increased by $15 million to $143 million in 2012 from $128 million in 2011 primarily due to:

- An increase of $9 million in amortization of regulatory assets primarily due to EmPower Maryland surcharge rate increases effective February 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $3 million due to utility plant additions, partially offset by lower depreciation rates.

The MPSC reduced Pepco's depreciation rates in Pepco's most recent electric distribution base rate case, which is expected to lower annual Depreciation and Amortization expense by approximately $27 million effective July 20, 2012.

Other Taxes

Other Taxes decreased by $9 million to $285 million in 2012 from $294 million in 2011. The decrease was primarily due to lower sales that resulted in decreases in the Montgomery County, Maryland and District of Columbia 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 $6 million to a net expense of $63 million in 2012 from a net expense of $57 million in 2011. The increase reflects a $6 million increase in interest expense primarily associated with higher long-term debt and lower capitalized interest.

Income Tax Expense

Pepco's income tax expense increased by $6 million to $38 million in 2012 from $32 million in 2011. Pepco's effective income tax rates for the nine months ended September 30, 2012 and 2011 were 27.3% and 26.7%, respectively. The effective income tax rates primarily reflect tax benefits recorded in each period related to asset removal costs and changes in estimates and interest related to uncertain and effectively settled tax positions, and a tax benefit recorded in 2011 for state tax refunds associated with prior years' asset dispositions.

In the first quarter of 2012, Pepco recorded income tax benefits of $10 million 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.

In the second quarter of 2011, PHI reached a settlement with the IRS with respect to interest due on its federal tax liabilities related to the tax years 1996 through 2002. In connection with this agreement, PHI reallocated certain amounts that have been on deposit with the IRS since 2006 among liabilities in the settlement years and subsequent years. Primarily related to the settlement and reallocations, Pepco recorded an additional tax benefit in the amount of $5 million (after-tax) in the second quarter of 2011.

In the second quarter of 2011, Pepco received refunds of approximately $5 million and recorded tax benefits of approximately $4 million (after-tax) related to the filing of amended state tax returns. These amended returns reduced state taxable income due to an increase in tax basis on certain prior years' asset dispositions.

Capital Requirements

Capital Expenditures

Pepco's capital expenditures for the nine months ended September 30, 2012 were $449 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. Pepco currently anticipates that its total 2012 capital expenditures will approximate its original projections of $512 million.

Pepco's projected capital expenditures for the five-year period from 2013 through 2017, reflecting changes due to the termination of the MAPP project, are summarized below. For an additional discussion of the termination of the MAPP project, see "General Overview – Termination of the MAPP Project" above. Pepco expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2013	2014	2015	2016	2017	Total
	(millions of dollars)					
Pepco						
Distribution	$409	$511	$497	$472	$443	$2,332
Distribution – Blueprint for the Future	8	—	—	—	—	8
Transmission	103	76	88	58	83	408
Other	57	59	38	34	29	217
Sub-Total	577	646	623	564	555	2,965
DOE Capital Reimbursement Awards (a)	(6)	—	—	—	—	(6)
Total Pepco	$571	$646	$623	$564	$555	$2,959

(a) Reflects remaining anticipated reimbursements pursuant to awards from the DOE under the American Recovery and Reinvestment Act of 2009.

MAPP/DOE Loan Program

To assist in the funding of the MAPP project, PHI had applied for a $684 million loan guarantee from the DOE for a substantial portion of the MAPP project, primarily the Calvert Cliffs to Indian River segment. With the termination of the MAPP project, PHI intends to withdraw its application for the loan guarantee.

DOE Capital Reimbursement Awards

In 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.

In April 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 Blueprint for the Future 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. During the nine months ended September 30, 2012, Pepco received award payments of $30 million. The cumulative award payments received by Pepco as of September 30, 2012, were $97 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 September 30, 2012, approximately 67% of delivered electricity sales were to Delaware customers and approximately 33% 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 (such as 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.

Blueprint for the Future

DPL is participating in a PHI initiative referred to as "Blueprint for the Future," which is designed to meet the challenges of rising energy costs, concerns about the environment, improved reliability and government energy reduction goals. For a discussion of the Blueprint for the Future initiative, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Blueprint for the Future."

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 most recent Delaware and Maryland base rate case filings 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 DPL of fully forecasted test years in future base rate cases. See Note (7), "Regulatory Matters – Rate Proceedings," to the financial statements of DPL for a discussion of each of these mechanisms. In its DPL base rate case order, the MPSC did not approve DPL's request 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, the parties to DPL's electric base rate case entered into a settlement agreement, which remains subject to DPSC approval, that does not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it does provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag.

In Maryland, the governor forwarded to the MPSC a report issued by his Grid Resiliency Task Force (see Note (7), "Regulatory Matters – Maryland Governor's Grid Resiliency Task Force" to the financial statements of DPL for additional discussion), urging the MPSC to quickly implement certain Task Force recommendations that would, among other things, accelerate reliability improvement investments and allow surcharge recovery for the accelerated investments. DPL is currently evaluating the report and its recommendations to determine what effect, if any, they may have on proposals to be made in DPL's future electric distribution base rate cases in Maryland to, among other things, mitigate the effects of regulatory lag. The form and substance of any such proposals will also depend, in part, on how the MPSC responds to the report and the governor's request.

DPL will continue to seek cost recovery from the MPSC and the DPSC 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 rate recovery mechanisms or base rate cases will fully mitigate the effects of regulatory lag. Until such time as any proposed or alternative mechanisms are approved, DPL plans to file rate cases at least annually in an effort to align more closely the revenue and related cash flow levels of DPL with its other operation and maintenance spending and capital investments. In light of the MPSC's decision in the most recent DPL base rate case, DPL intends to file its next electric distribution base rate case with the MPSC in the first quarter of 2013.

Termination of the MAPP Project

On August 24, 2012, the board of PJM notified PHI, on behalf of its subsidiaries Pepco and DPL, that the MAPP project has been terminated and removed from PJM's regional transmission expansion plan. PHI was originally 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 of PJM's decision, on October 2, 2012, DPL filed with the MPSC a notice withdrawing its pending application related to the MAPP project. DPL had included in its five-year projected capital expenditures $67 million of MAPP-related expenditures for the period from 2012 to 2016. DPL has updated its five-year projected capital expenditures to remove the MAAP-related expenditures to reflect the PJM decision. See "Capital Requirements – Capital Expenditures" for a discussion of DPL's projected capital expenditures.

As of September 30, 2012, DPL's total capital expenditures for the MAPP project were approximately $37 million. Under the terms of the FERC order approving an incentive rate for the MAPP project, FERC authorized the recovery of abandoned costs prudently incurred in connection with the MAPP project. Consistent with this order, PHI intends to seek recovery of abandoned MAPP capital expenditures through a filing expected to be submitted to the FERC in the fourth quarter of 2012. The FERC filing is expected to address, among other things, the period over which the abandoned costs are to be recovered and the rate of return on these costs during the recovery period. Under an order issued by the FERC in 2008, DPL is currently allowed to include its MAPP capital expenditures in its rate base, earning an incentive rate of return of 12.8% during the construction period.

As of September 30, 2012, DPL had reclassified all $37 million of capital expenditures with respect to the MAPP project to a regulatory asset. The regulatory asset includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. DPL intends to reduce the regulatory asset by any amounts recovered from the sale or alternative use of the land and land rights.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2012 to the nine months ended September 30, 2011. All amounts in the tables (except sales and customers) are in millions of dollars.

Electric Operating Revenue

	2012	2011	Change
Regulated T&D Electric Revenue	$340	$299	$ 41
Default Electricity Supply Revenue	458	531	(73)
Other Electric Revenue	10	11	(1)
Total Electric Operating Revenue	$808	$841	$ (33)

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 territory 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

	2012	2011	Change
Regulated T&D Electric Revenue			
Residential	$ 161	$ 144	$ 17
Commercial and industrial	97	84	13
Transmission and other	82	71	11
Total Regulated T&D Electric Revenue	$ 340	$ 299	$ 41

	2012	2011	Change
Regulated T&D Electric Sales (GWh)			
Residential	3,931	4,121	(190)
Commercial and industrial	5,726	5,610	116
Transmission and other	37	36	1
Total Regulated T&D Electric Sales	9,694	9,767	(73)

	2012	2011	Change
Regulated T&D Electric Customers (in thousands)			
Residential	442	441	1
Commercial and industrial	59	59	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	502	501	1

Regulated T&D Electric Revenue increased by $41 million primarily due to:

- An increase of $14 million due to distribution rate increases in Maryland effective July 2012 and July 2011; and in Delaware effective July 2012.
- An increase of $10 million in transmission revenue primarily attributable to higher rates effective June 2012 and June 2011 related to increases in transmission plant investment and operating expenses.
- An increase of $10 million primarily due to a 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 $4 million due to an EmPower Maryland (a demand side management program) rate increase in February 2012 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $2 million due to higher non-weather related average customer usage.

The aggregate amount of these increases was partially offset by a decrease of $2 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.

Default Electricity Supply

	2012	2011	Change
Default Electricity Supply Revenue			
Residential	$ 354	$ 406	$ (52)
Commercial and industrial	96	116	(20)
Other	8	9	(1)
Total Default Electricity Supply Revenue	$ 458	$ 531	$ (73)

	2012	2011	Change
Default Electricity Supply Sales (GWh)			
Residential	3,583	3,861	(278)
Commercial and industrial	1,311	1,392	(81)
Other	22	22	—
Total Default Electricity Supply Sales	4,916	5,275	(359)

	2012	2011	Change
Default Electricity Supply Customers (in thousands)			
Residential	405	416	(11)
Commercial and industrial	40	43	(3)
Other	—	—	—
Total Default Electricity Supply Customers	445	459	(14)

Default Electricity Supply Revenue decreased by $73 million primarily due to:

- A decrease of $38 million as a result of lower Default Electricity Supply rates.
- A decrease of $21 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $19 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.

The aggregate amount of these decreases was partially offset by an increase of $5 million due to higher non-weather related average customer usage.

The following table shows the percentages of DPL's total distribution sales by jurisdiction that are derived from customers receiving Default Electricity Supply from DPL. Amounts are for the nine months ended September 30:

	2012	2011
Sales to Delaware customers	49%	51%
Sales to Maryland customers	54%	59%

Natural Gas Operating Revenue

	2012	2011	Change
Regulated Gas Revenue	$102	$134	$ (32)
Other Gas Revenue	22	35	(13)
Total Natural Gas Operating Revenue	$124	$169	$ (45)

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 consists of 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

	2012	2011	Change
Regulated Gas Revenue			
Residential	$ 63	$ 82	$ (19)
Commercial and industrial	32	45	(13)
Transportation and other	7	7	—
Total Regulated Gas Revenue	$ 102	$ 134	$ (32)

	2012	2011	Change
Regulated Gas Sales (million cubic feet)			
Residential	4,052	5,338	(1,286)
Commercial and industrial	2,310	3,207	(897)
Transportation and other	4,877	5,210	(333)
Total Regulated Gas Sales	11,239	13,755	(2,516)

	2012	2011	Change
Regulated Gas Customers (in thousands)			
Residential	115	114	1
Commercial and industrial	9	9	—
Transportation and other	—	—	—
Total Regulated Gas Customers	124	123	1

Regulated Gas Revenue decreased by $32 million primarily due to:

- A decrease of $17 million due to lower sales primarily as a result of milder weather during the winter months of 2012, as compared to 2011.
- A decrease of $10 million due to lower non-weather related average customer usage.
- A decrease 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).
- A decrease of $2 million due to a GCR decrease effective November 2011.

The aggregate amount of these decreases was partially offset by an increase of $1 million due to a gas distribution rate increase effective July 2011.

Other Gas Revenue

Other Gas Revenue decreased by $13 million primarily due to lower average prices and lower volumes for off-system sales to electric generators and gas marketers.

<u>*Operating Expenses*</u>

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 decreased by $64 million to $443 million in 2012 from $507 million in 2011 primarily due to:

- A decrease of $36 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $16 million due to lower electricity sales primarily as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A decrease of $15 million primarily due to customer migration to competitive suppliers.
- A decrease of $4 million in deferred electricity expense resulting from an adjustment recorded by DPL in June 2012 related to the under-recognition of allowed revenues on Default Electricity Supply procurement and transmission taxes in Delaware.

The aggregate amount of these decreases was partially offset by an increase of $7 million in deferred electricity expense primarily due to lower Default Electricity Supply rates, which resulted in a higher rate of recovery of Default Electricity Supply costs.

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 decreased by $37 million to $77 million in 2012 from $114 million in 2011 primarily due to:

- A decrease of $21 million in the cost of gas purchases for on-system sales as a result of lower average gas prices and lower volumes purchased.
- A decrease of $11 million in the cost of gas purchases for off-system sales as a result of lower average gas prices and volumes purchased.
- A decrease of $6 million from the settlement of financial hedges entered into as part of DPL’s hedge program for the purchase of regulated natural gas.
- A decrease of $4 million in 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 a decrease in Regulated Gas Revenue).

The aggregate amount of these decreases was partially offset by an increase of $5 million in deferred gas expense as a result of a higher rate of recovery of natural gas supply costs.

Other Operation and Maintenance

Other Operation and Maintenance increased by $11 million to $192 million in 2012 from $181 million in 2011 primarily due to:

- An increase of $4 million resulting from a decrease in deferred cost adjustments associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on working capital in 2011 and allowed returns on net uncollectible expense and regulatory taxes in 2012.
- An increase of $4 million in employee-related costs, primarily pension and other employee benefits.
- An increase of $3 million primarily due to higher maintenance costs.
- An increase of $3 million in customer support service and system support costs.
- An increase of $2 million due to a 2011 reduction in self-insurance reserves for general and auto liability claims.
- An increase of $2 million in expenses related to regulatory filings.

The aggregate amount of these increases was partially offset by:

- A decrease of $4 million in other storm restoration costs.
- A decrease of $3 million in total incremental storm restoration costs for major storm events, as described in the following table:

	2012	2011	Change
Costs associated with derecho storm (June 2012)	$ 2	$—	$ 2
Regulatory asset established for future recovery of derecho storm costs	(1)	—	(1)
Costs associated with Hurricane Irene (August 2011)	—	9	(9)
Regulatory asset established for future recovery of Hurricane Irene costs	—	(5)	5
Total incremental major storm restoration costs	$ 1	$ 4	$ (3)

  - In the second and third quarters of 2012, DPL incurred incremental storm restoration costs of $2 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of DPL's service territories. DPL deferred $1 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in Maryland and will be pursuing recovery of the incremental storm restoration costs in this jurisdiction during the next distribution base rate case. The remaining costs of $1 million relate to repair work completed in Delaware which are not currently deferrable.
  - In the third quarter of 2011, DPL incurred incremental storm restoration costs of $9 million associated with Hurricane Irene which also resulted in widespread damage to the electric distribution system in each of DPL's service territories. DPL deferred $5 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in Maryland. The MPSC approved the recovery of these costs in Maryland for DPL in its July 2012 rate order. The remaining costs of $4 million relate to repair work completed in Delaware which are not currently deferrable.

Depreciation and Amortization

Depreciation and Amortization expense increased by $12 million to $78 million in 2012 from $66 million in 2011 primarily due to:

- An increase of $4 million in the Delaware Renewable Energy Portfolio Standards deferral associated with the over-recovery of renewable energy procurement costs (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $4 million in amortization of regulatory assets primarily due to 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 $2 million due to utility plant additions.

The MPSC reduced DPL's depreciation rates in DPL's most recent electric distribution base rate case, which is expected to lower annual Depreciation and Amortization expense by approximately $4 million effective July 20, 2012.

Income Tax Expense

DPL's income tax expense increased by $2 million to $34 million in 2012 from $32 million in 2011. DPL's effective income tax rates for the nine months ended September 30, 2012 and 2011 were 37.8% and 36.4%, respectively. The increase in the effective income tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

During the second quarter of 2011, PHI reached a settlement with the IRS with respect to interest due on its federal tax liabilities related to the tax years 1996 through 2002. In connection with this agreement, PHI reallocated certain amounts that have been on deposit with the IRS since 2006 among liabilities in the settlement years and subsequent years. Primarily related to the settlement and reallocations, DPL recorded an additional $4 million (after-tax) interest benefit in the second quarter of 2011. This benefit is partially offset by the adjustments recorded in the third quarter of 2011 related to DPL's settlement with the state taxing authorities resulting in $1 million (after-tax) of additional tax expense, and tax expense of $1 million (after-tax) associated with the recalculation of interest on uncertain tax positions for open tax years using different assumptions related to the application of its deposit made with the IRS in 2006.

The increase in the effective income tax rate was partially offset by the adjustments to prior year taxes and additional tax benefits recorded related to depreciation on property, plant and equipment purchased prior to 1975.

Capital Requirements

Capital Expenditures

DPL's capital expenditures for the nine months ended September 30, 2012 were $219 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. DPL currently anticipates that its total 2012 capital expenditures will approximate its original projections of $406 million.

DPL's projected capital expenditures for the five-year period from 2013 through 2017, reflecting changes due to the termination of the MAPP project, are summarized below. For an additional discussion of the termination of the MAPP project, see "General Overview – Termination of the MAPP Project" above. DPL expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2013	2014	2015	2016	2017	Total
	(millions of dollars)					
DPL						
Distribution	$159	$144	$141	$145	$149	$ 738
Distribution - Blueprint for the Future	33	1	—	—	—	34
Transmission	110	94	99	103	148	554
Gas Delivery	26	28	28	28	30	140
Other	46	35	28	24	30	163
Total DPL	$374	$302	$296	$300	$357	$1,629

MAPP/DOE Loan Program

To assist in the funding of the MAPP project, PHI had applied for a $684 million loan guarantee from the DOE for a substantial portion of the MAPP project, primarily the Calvert Cliffs to Indian River segment. With the termination of the MAPP project, PHI intends to withdraw its application for the loan guarantee.

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. 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.

Blueprint for the Future

ACE is participating in a PHI initiative referred to as "Blueprint for the Future," which is designed to meet the challenges of rising energy costs, concerns about the environment, improved reliability and government energy reduction goals. For a discussion of the Blueprint for the Future initiative, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Blueprint for the Future."

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 the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." ACE is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth. The NJBPU has approved certain rate recovery mechanisms in connection with ACE's Infrastructure Investment Program, which ACE had proposed to extend and expand; however, ACE agreed as part of the settlement of its electric distribution base rate case to withdraw without prejudice its filing to extend and expand its Infrastructure Investment Program. There can be no assurance that this proposal or any other attempts by ACE to mitigate regulatory lag will be approved, or that even if approved, the rate recovery mechanisms or any base rate cases will fully ameliorate the effects of regulatory lag. Until such time as any proposed or alternative mechanisms are approved, ACE plans to file rate cases at least annually in an effort to align more closely its revenue and related cash flow levels with other operation and maintenance spending and capital investments. In future rate cases, ACE will continue to seek cost recovery from the NJBPU to reduce the effects of regulatory lag.

Termination of the MAPP Project

In 2007, PJM (the regional transmission organization that is responsible for planning the transmission grid and coordinating the movement of wholesale electricity within a region consisting of all or parts of 13 states and the District of Columbia) directed PHI to construct a high-voltage interstate transmission line to address the reliability needs of the region's transmission system. In its most recent configuration, the MAPP project would have covered 152 miles, originating at the Possum Point substation in northern Virginia, traversing under the Chesapeake Bay and ending at the Indian River substation in Delaware. The original project extended the proposed transmission line from the Indian River substation to the Salem substation in ACE's service territory in southern New Jersey, however, this portion of the project was terminated in May 2009. On August 24, 2012, the board of PJM notified PHI that the MAPP project has been terminated in its entirety and removed from PJM's regional transmission expansion plan.

As of September 30, 2012, ACE had no capital expenditures associated with the MAPP project.

Consolidated Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2012 to the nine months ended September 30, 2011. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

	2012	2011	Change
Regulated T&D Electric Revenue	$299	$ 303	$ (4)
Default Electricity Supply Revenue	628	701	(73)
Other Electric Revenue	12	14	(2)
Total Operating Revenue	$939	$1,018	$ (79)

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 issued by ACE Funding, 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

	2012	2011	Change
Regulated T&D Electric Revenue			
Residential	$ 133	$ 137	$ (4)
Commercial and industrial	98	95	3
Transmission and other	68	71	(3)
Total Regulated T&D Electric Revenue	$ 299	$ 303	$ (4)

	2012	2011	Change
Regulated T&D Electric Sales (GWh)			
Residential	3,471	3,647	(176)
Commercial and industrial	3,898	3,987	(89)
Transmission and other	33	32	1
Total Regulated T&D Electric Sales	7,402	7,666	(264)

	2012	2011	Change
Regulated T&D Electric Customers (in thousands)			
Residential	481	482	(1)
Commercial and industrial	65	65	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	547	548	(1)

Regulated T&D Electric Revenue decreased by $4 million primarily due to:

- A decrease of $5 million due to lower non-weather related average customer usage.
- A decrease of $4 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A decrease of $3 million in transmission revenue primarily attributable to lower rates effective June 1, 2011.

The aggregate amount of these decreases was partially offset by an increase of $8 million primarily due to a rate increase in the New Jersey Societal Benefit Charge effective July 2012 (which is offset in Deferred Electric Services Costs and Other Operation and Maintenance).

Default Electricity Supply

	2012	2011	Change
Default Electricity Supply Revenue			
Residential	$391	$402	$ (11)
Commercial and industrial	168	189	(21)
Other	69	110	(41)
Total Default Electricity Supply Revenue	$628	$701	$ (73)

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.

	2012	2011	Change
Default Electricity Supply Sales (GWh)			
Residential	2,876	3,214	(338)
Commercial and industrial	974	1,161	(187)
Other	14	26	(12)
Total Default Electricity Supply Sales	3,864	4,401	(537)

	2012	2011	Change
Default Electricity Supply Customers (in thousands)			
Residential	400	423	(23)
Commercial and industrial	46	50	(4)
Other	—	1	(1)
Total Default Electricity Supply Customers	446	474	(28)

Default Electricity Supply Revenue decreased by $73 million primarily due to:

- A decrease of $42 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $41 million in wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from NUGs.
- A decrease of $15 million due to lower non-weather related average customer usage.
- A decrease of $7 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.

The aggregate amount of these decreases was partially offset by an increase of $32 million as a result of higher Default Electricity Supply rates, primarily due to Basic Generation Charge rate increases that became effective in June 2011 and June 2012.

Total Default Electricity Supply Revenue for the nine months ended September 30, 2012 includes a decrease of $2 million in unbilled revenue attributable to ACE's BGS ($1 million decrease in net income), primarily due to lower weather-related average customer usage during the unbilled revenue period at September 30, 2012 as compared to the corresponding period in 2011. 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.

For the nine months ended September 30, 2012 and 2011, the percentages of ACE's total distribution sales that are derived from customers receiving Default Electricity Supply are 52% and 57%, 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 $93 million to $555 million in 2012 from $648 million in 2011 primarily due to:

- A decrease of $45 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $40 million primarily due to customer migration to competitive suppliers.
- A decrease of $8 million due to lower electricity sales primarily as a result of milder weather during the 2012 winter and spring months, as compared to 2011.

Other Operation and Maintenance

Other Operation and Maintenance expense increased by $11 million to $178 million in 2012 from $167 million in 2011 primarily due to:

- An increase of $4 million in customer support service and system support costs.
- An increase of $4 million in New Jersey Societal Benefit Program costs that are deferred and recoverable.
- An increase of $3 million in employee-related-costs, primarily due to pension and other benefit expenses.

Other Operation and Maintenance expense also includes the effects of total incremental storm restoration costs for major storm events as described in the following table:

	2012	2011	Change
Costs associated with derecho storm (June 2012)	$ 13	$—	$ 13
Regulatory asset established for future recovery of derecho storm costs	(13)	—	(13)
Costs associated with Hurricane Irene (August 2011)	—	7	(7)
Regulatory asset established for future recovery of Hurricane Irene costs	—	(7)	7
Total incremental major storm restoration costs	$—	$—	$ —

- In the second and third quarters of 2012, ACE incurred incremental storm restoration costs of $13 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system. ACE deferred all of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in New Jersey and will be pursuing recovery of the incremental storm restoration costs during its next distribution base rate case.
- In the third quarter of 2011, ACE incurred incremental storm restoration costs of $7 million associated with Hurricane Irene which also resulted in widespread damage to the electric distribution system. ACE deferred all of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in New Jersey. ACE's stipulation of settlement approved by the NJBPU in October 2012 provides for recovery of these costs in New Jersey.

Depreciation and Amortization

Depreciation and Amortization expense decreased by $15 million to $92 million in 2012 from $107 million in 2011 primarily due to a decrease of $16 million in amortization of stranded costs primarily as the result of lower revenue due to rate decreases effective October 2011 for the ACE Transition Bond Charge and Market Transition Charge Tax (partially offset in Default Electricity Supply Revenue). The decrease was partially offset by an increase of $3 million due to utility plant additions.

Other Taxes

Other Taxes decreased by $5 million to $14 million in 2012 from $19 million in 2011. The decrease was primarily due to decreased Transitional Energy Facility Assessment taxes due to a rate decrease effective January 2012 (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 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 $43 million, to an expense reduction of $6 million in 2012 as compared to an expense reduction of $49 million in 2011, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply revenue rates, partially offset by higher electricity supply costs.

Income Tax Expense

ACE's consolidated income tax expense decreased by $15 million to $21 million in 2012 from $36 million in 2011. ACE's consolidated effective income tax rates for the nine months ended September 30, 2012 and 2011 were 36.8% and 46.8%, respectively. The decrease in the effective income tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions and a deferred tax adjustment.

During the second quarter of 2011, PHI reached a settlement with the IRS with respect to interest due on its federal tax liabilities related to the November 2010 audit settlement for years 1996 through 2002. In connection with this agreement, PHI reallocated certain amounts that have been on deposit with the IRS since 2006 among liabilities in the settlement years and subsequent years. Primarily related to the settlement and reallocations, ACE recorded an additional $1 million (after-tax) of interest due to the IRS. This additional interest expense was recorded in the second quarter of 2011. This expense was further impacted by the adjustment recorded in the third quarter of 2011 related to the recalculation of interest on its uncertain tax positions for open tax years using different assumptions related to the application of its deposit made with the IRS in 2006.

Also during the second quarter of 2011, ACE completed a reconciliation of its deferred taxes on certain regulatory assets and, as a result, recorded a $1 million increase to income tax expense.

Capital Requirements

Capital Expenditures

ACE's capital expenditures for the nine months ended September 30, 2012 were $186 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. ACE currently anticipates that its total 2012 capital expenditures will approximate its original projections of $225 million.

As a result of the termination of the MAPP project, PHI has revised its projected capital expenditures for the Power Delivery business for the five-year period from 2013 through 2017. Although ACE had no MAPP expenditures budgeted for the five-year period from 2012 through 2016, ACE's projected expenditures for the five-year period from 2013 through 2017 were updated and are summarized below. For an additional discussion of the termination of the MAPP project, see "General Overview – Termination of the MAPP Project" above.

	For the Year Ended December 31,					
	2013	2014	2015	2016	2017	Total
			(millions of dollars)			
ACE						
Distribution	$165	$146	$146	$136	$138	$ 731
Distribution - Blueprint for the Future	—	—	—	8	45	53
Transmission	53	84	93	81	67	378
Other	36	32	36	22	24	150
Sub-Total	254	262	275	247	274	1,312
DOE Capital Reimbursement Awards (a)	(1)	—	—	—	—	(1)
Total ACE	$253	$262	$275	$247	$274	$1,311

(a) Reflects remaining anticipated reimbursements pursuant to awards from the DOE under the American Recovery and Reinvestment Act of 2009.

DOE Capital Reimbursement Awards

In 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.

In April 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 Blueprint for the Future 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. During the nine months ended September 30, 2012, ACE received award payments of $4 million. The cumulative award payments received by ACE as of September 30, 2012, were $12 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 (15), "Derivative Instruments and Hedging Activities," and Note (20), "Discontinued Operations," of the consolidated financial statements of PHI included in its 2011 Form 10-K, Part I, Item 7A. Quantitative and Qualitative Disclosures About Market Risk in PHI's 2011 Form 10-K, and Note (13), "Derivative Instruments and Hedging Activities," of the consolidated financial statements of PHI included herein.

Pepco Holdings, Inc.

Commodity Price Risk

The Pepco Energy Services segment engages in commodity risk management activities to reduce its financial exposure to changes in the value of its assets and obligations due to commodity price fluctuations. Certain of these risk management activities are conducted using instruments classified as derivatives based on Financial Accounting Standards Board (FASB) guidance on derivatives and hedging, (ASC 815). Pepco Energy Services also manages commodity risk with contracts that are not classified as derivatives.

PHI's risk management policies place oversight at the senior management level through the CRMC, which has the responsibility for establishing corporate compliance requirements for energy market participation. PHI collectively refers to these energy market activities, including its commodity risk management activities, as "energy commodity" activities. PHI uses a value-at-risk (VaR) model to assess the market risk of the energy commodity activities of Pepco Energy Services. PHI also uses other measures to limit and monitor risk in its energy commodity activities, including limits on the nominal size of positions and periodic loss limits. VaR represents the potential fair value loss on energy contracts or portfolios due to changes in market prices for a specified time period and confidence level. PHI uses a delta-gamma VaR estimation model. The other parameters include a 95 percent, one-tailed confidence level and a one-day holding period. Since VaR is an estimate, it is not necessarily indicative of actual results that may occur.

The table below provides the VaR associated with energy contracts of the Pepco Energy Services segment for the nine months ended September 30, 2012 in millions of dollars:

	VaR (a)
95% confidence level, one-day holding period, one-tailed	
Period end	$ 1
Average for the period	$ 1
High	$ 1
Low	$ 1

(a) This column represents all energy derivative contracts, normal purchase and normal sales contracts, modeled generation output and fuel requirements, and modeled customer load obligations for Pepco Energy Services' energy commodity activities.

Pepco Energy Services purchases electric and natural gas futures, swaps, options and forward contracts to hedge price risk in connection with the purchase of physical natural gas and electricity for distribution to customers. Pepco Energy Services accounts for its derivatives as either cash flow hedges of forecasted transactions or they are marked to market through current earnings. Forward contracts that meet the requirements for normal purchase and normal sale accounting under FASB guidance on derivatives and hedging are recorded on an accrual basis.

Credit and Nonperformance Risk

The following table provides information on the credit exposure on competitive wholesale energy contracts, net of collateral, to wholesale counterparties as of September 30, 2012, in millions of dollars:

Rating	Exposure Before Credit Collateral (b)	Credit Collateral (c)	Net Exposure	Number of Counterparties Greater Than 10% (d)	Net Exposure of Counterparties Greater Than 10%
Investment Grade (a)	$ 1	$ —	$ 1	2	$ —
Non-Investment Grade	—	—	—	—	—
No External Ratings	—	—	—	1	—
Credit reserves	—	—	—	—	—

(a) Investment Grade – primarily determined using publicly available credit ratings of the counterparty. If the counterparty has provided a guarantee by a higher-rated entity (e.g., its parent), it is determined based upon the rating of its guarantor. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's or Moody's Investor Service rating of BBB- or Baa3, respectively.

(b) Exposure before credit collateral – includes the marked to market (MTM) energy contract net assets for open/unrealized transactions, the net receivable/payable for realized transactions and net open positions for contracts not marked to market. Amounts due from counterparties are offset by liabilities payable to those counterparties to the extent that legally enforceable netting arrangements are in place. Thus, this column presents the net credit exposure to counterparties after reflecting all allowable netting, but before considering collateral held.

(c) Credit collateral – the face amount of cash deposits, letters of credit and performance bonds received from counterparties, not adjusted for probability of default, and, if applicable, property interests (including oil and gas reserves).

(d) Using a percentage of the total exposure.

For information regarding "Interest Rate Risk," please refer to Part I, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, in Pepco Holdings' 2011 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 Securities Exchange Act of 1934, as amended (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 the 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 September 30, 2012, 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 September 30, 2012, 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 2011 Form 10-K. There have been no material changes to any Reporting Company's risk factors as disclosed in the 2011 Form 10-K, except as set forth below.

The provisions contained in certain forward sale agreements entered into by PHI in connection with its March 2012 equity offering subject PHI to risks if certain events occur. (PHI only)

In March 2012, PHI entered into forward sale agreements with a forward counterparty, relating to the issuance and sale by PHI, and the purchase by the forward counterparty, of an aggregate of up to 17.9 million shares of PHI common stock. Upon physical settlement of the forward sale agreements, PHI will receive from the forward counterparty a stated per share amount of cash, subject to certain adjustments pursuant to the terms of the forward sale agreements.

The forward counterparty may accelerate settlement of the forward sale agreements and require PHI to physically settle the forward sale agreements on a date of its choosing under certain circumstances set forth in the forward sale agreements. Such a decision could be made regardless of PHI's interests, including its need for capital. In the case of such an acceleration, PHI could be required to issue and deliver shares of common stock under the physical settlement provisions of the forward sale agreements regardless of its capital needs or earlier than when PHI would otherwise have elected to settle the forward sale agreements. Moreover, PHI would no longer be permitted to elect that cash or net share settlement apply, which could result in dilution to PHI's earnings per share and return on equity.

Except in certain circumstances, PHI has the right to elect physical, cash or net share settlement under the forward sale agreements. Delivery of any shares upon physical settlement or net share settlement could result in dilution to PHI's earnings per share and return on equity. If PHI elects cash or net share settlement, the forward counterparty or one of its affiliates would likely purchase shares of common stock in open market transactions over a period of time in connection with such settlement and its related hedge position. If the price at which the forward counterparty or its affiliate makes these purchases exceeds the applicable forward sale price, then PHI would be required to deliver to the forward counterparty an amount equal to the difference in cash (in the case of cash settlement) or in a number of shares with a value equal to such difference (in the case of net share settlement). Accordingly, PHI may need to deliver a substantial amount of cash or a substantial number of shares of common stock, which could result in dilution to PHI's earnings per share and return on equity. Furthermore, these purchases of common stock by the forward counterparty or its affiliate could increase the trading price of PHI's common stock above the trading prices that would otherwise prevail. This, in turn, could increase the amount of cash, in the case of cash settlement, or the number of shares, in the case of net share settlement, PHI would owe, if any, to the forward counterparty upon settlement of the forward sale agreements.

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

As of December 31, 2011, 55% 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.

Four of the collective bargaining agreements to which PHI's subsidiaries are a party will expire within the next four years. A fifth agreement was successfully renegotiated in October 2012 for a new four-year term. Though PHI believes that a protracted work stoppage is 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 its term loan agreement 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 PHI's term loan agreement entered into in April 2012, 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 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 the affected 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, a further write-down of 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.

PHI utility subsidiaries are subject to comprehensive regulation which may significantly affect their operations. PHI's utility subsidiaries may be subject to fines, penalties and other sanctions for the inability to meet these requirements.

The regulated utilities that comprise Power Delivery are subject to extensive regulation by various federal, state and local regulatory agencies. Each of Pepco, DPL and ACE is regulated by the state agencies for each service territory in which it operates, with respect to, among other things, the manner in which utility service is provided to customers, as well as rates it can charge customers for the distribution and supply of electricity (and, additionally for DPL, the distribution and supply of natural gas). NERC has also established, and FERC has approved, reliability standards with regard to the bulk power system that impose certain operating, planning and cyber security requirements on Pepco, DPL, ACE and Pepco Energy Services. Further, FERC regulates the electricity transmission facilities of Pepco, DPL and ACE.

Approval of these regulators is required in connection with changes in rates and other aspects of the utilities' operations. These regulatory authorities, and NERC with respect to electric reliability, are empowered to impose financial penalties, fines and other sanctions against the utilities for non-compliance with certain rules and regulations. In this regard, in December 2011, the MPSC sanctioned Pepco related to its reliability in connection with major storm events that occurred in July and August 2010. These sanctions included imposing a fine on Pepco and requiring Pepco to file a work plan detailing, among other things, its reliability improvement objectives and progress in meeting those objectives, while raising the possibility of additional fines or cost recovery disallowances for failing to meet those objectives. The MPSC also stated that it would consider in Pepco's latest Maryland retail base rate case the potential disallowance of the recovery of costs which may be determined to have been imprudently incurred. In this base rate case, the MPSC set rates at a level that was not adequate to recover costs that Pepco will incur during the period the rates are in effect.

NERC's eight regional oversight entities, including Reliability*First* Corporation (RFC), of which Pepco, DPL, ACE and Pepco Energy Services are members, and Northeast Power Coordinating Council (NPCC), of which Pepco Energy Services is a member, are charged with the day-to-day implementation and enforcement of NERC's standards. RFC and NPCC perform compliance audits on entities registered with NERC based on reliability standards and criteria established by NERC. NERC, RFC and NPCC also conduct compliance investigations in response to a system disturbance, complaint, or possible violation of a reliability standard identified by other means. Pepco, DPL, ACE and Pepco Energy Services are subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards requested by FERC to increase the number of assets (including cyber security assets) subject to NERC cyber security standards that are designated as "critical assets." From time to time, Pepco, DPL and ACE have entered into settlement agreements with RFC resolving alleged violations and resulting in fines. There can be no assurance that additional settlements resolving issues related to RFC or NPCC requirements will not occur in the future. The imposition of additional sanctions and civil fines by these enforcement entities could have a material adverse effect on a Reporting Company's results of operations, cash flow and financial condition.

PHI's utility subsidiaries, as well as Pepco Energy Services, are also required to have numerous permits, approvals and certificates from governmental agencies that regulate their businesses. Although PHI believes that each of its subsidiaries has, and each of Pepco, DPL and ACE believes it has, obtained or sought renewal of the material permits, approvals and certificates necessary for its existing operations and that its business is conducted in accordance with applicable laws, PHI is unable to predict the impact that future regulatory activities may have on its business. Changes in or reinterpretations of existing laws or regulations, or the imposition of new laws or regulations, may require any one or more of PHI's subsidiaries to incur additional expenses or significant capital expenditures or to change the way it conducts its operations.

PHI's profitability is largely dependent on its ability to recover costs of providing utility services to its customers and to earn an adequate return on its capital investments. The failure of PHI to obtain timely recognition of costs in its rates may have a negative effect on PHI's results of operations and financial condition.

The public service commissions which regulate PHI's utility subsidiaries establish utility rates and tariffs intended to provide the utility the opportunity to obtain revenues sufficient to recover its prudently incurred costs, together with a reasonable return on investor supplied capital. These regulatory authorities also determine how Pepco, ACE and DPL recover from their customers purchased power and natural gas and other operating costs, including transmission and other costs. The utilities cannot change their rates without approval by the applicable regulatory authority. There can be no assurance that the regulatory authorities will consider all costs to have been prudently incurred, nor can there be any assurance that the regulatory process by which rates are determined will always result in rates that achieve full and timely recovery of costs or a just and reasonable rate of return on investments. In addition, if the costs incurred by any of the utilities in operating its business exceed the amounts on which its approved rates are based, the financial results of that utility, and correspondingly PHI, may be adversely affected.

PHI's utility subsidiaries are also exposed to "regulatory lag," which refers to a shortfall in revenues due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. All of PHI's utilities are currently experiencing significant regulatory lag because their investment in the rate base and their operating expenses are outpacing revenue growth. PHI anticipates that this trend will continue for the foreseeable future. The failure to timely recognize costs in rates could have a material adverse effect on PHI's and each utility subsidiary's business, results of operations, cash flow and financial condition.

In their most recent rate cases, Pepco (in the District of Columbia and Maryland), DPL (in Maryland and Delaware) and ACE (in New Jersey) have proposed mechanisms that would track reliability and other expenses and permit each utility to make adjustments in its approved rates to account for prudent investments as made, thereby seeking to reduce the magnitude of regulatory lag. However, the MPSC and the DCPSC did not approve in substantial part requests by Pepco (in Maryland and the District of Columbia) and DPL (in Maryland) to implement regulatory lag mitigation mechanisms. In Delaware, the parties to DPL's electric base rate case entered into a settlement agreement, which remains subject to DPSC approval, that does not include these mechanisms. In New Jersey, the NJBPU has previously approved a similar mechanism; however, ACE agreed as part of the settlement of its electric distribution base rate case to withdraw without prejudice its filing with the NJBPU to extend and expand that previously approved mechanism. There can be no assurance that any of the outstanding proposals or any other attempts by Pepco, DPL and ACE to mitigate regulatory lag will be approved, or that even if approved, the rate recovery mechanisms will fully mitigate the effects of regulatory lag. If necessary to address in whole or in part the problem of regulatory lag, each utility can file (and Pepco and DPL presently intend to file) base rate cases annually (or even more frequently) to seek to align its revenue and related cash flow levels allowed by the applicable public service commissions with operation and maintenance spending and capital investments. The inability of PHI's utility subsidiaries to obtain relief from the impact of regulatory lag through base rate cases or otherwise may have an adverse effect on the business, results of operations, cash flow and financial condition of PHI and each utility subsidiary.

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, furnished or submitted 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 to PHI's Form 8-K, December 21, 2011.
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.
10.1	PHI	Employment Agreement, dated September 7, 2012, by and between PHI and Kevin C. Fitzgerald	Filed herewith.
10.2	PHI	Retirement Agreement, dated September 6, 2012, by and between PHI and Kirk J. Emge.	Exhibit 10 to PHI's Form 8-K, September 7, 2012.
12.1	PHI	Statements Re: Computation of Ratios	Filed herewith.
12.2	Pepco	Statements Re: Computation of Ratios	Filed herewith.
12.3	DPL	Statements Re: Computation of Ratios	Filed herewith.
12.4	ACE	Statements Re: Computation of Ratios	Filed herewith.
31.1	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.2	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.3	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.4	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.5	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.6	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.7	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.8	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
32.1	PHI	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
32.2	Pepco	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
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.
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 each Reporting Company 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)

November 5, 2012

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

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 to PHI's Form 8-K, December 21, 2011.
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.
10.1	PHI	Employment Agreement, dated September 7, 2012, by and between PHI and Kevin C. Fitzgerald	Filed herewith.
10.2	PHI	Retirement Agreement, dated September 6, 2012, by and between PHI and Kirk J. Emge.	Exhibit 10 to PHI's Form 8-K, September 7, 2012.
12.1	PHI	Statements Re: Computation of Ratios	Filed herewith.
12.2	Pepco	Statements Re: Computation of Ratios	Filed herewith.
12.3	DPL	Statements Re: Computation of Ratios	Filed herewith.
12.4	ACE	Statements Re: Computation of Ratios	Filed herewith.
31.1	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.2	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.3	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.4	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.5	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.6	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.7	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.8	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
101.INS	PHI Pepco DPL ACE	XBRL Instance Document	Filed herewith.
101.SCH	PHI Pepco DPL ACE	XBRL Taxonomy Extension Schema Document	Filed herewith.
101.CAL	PHI Pepco DPL ACE	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith.
101.DEF	PHI Pepco DPL ACE	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith.
101.LAB	PHI Pepco DPL ACE	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith.
101.PRE	PHI Pepco DPL ACE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith.

INDEX TO EXHIBITS FURNISHED HEREWITH

Exhibit No.	Registrant(s)	Description of Exhibit
32.1	PHI	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.2	Pepco	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.3	DPL	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.4	ACE	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350

Exhibit 12.1

Pepco Holdings, Inc.

	Nine Months Ended September 30, 2012	For the Year Ended December 31, 2011	2010	2009	2008	2007
		(millions of dollars)				
Income from continuing operations (a)	$ 242	$ 263	$ 140	$ 221	$ 187	$ 254
Income tax expense	142	149	11	104	90	141
Fixed charges:						
Interest on long-term debt, amortization of discount, premium and expense	204	265	315	348	311	315
Other interest	17	22	22	23	24	25
Preferred dividend requirements of subsidiaries	—	—	—	—	—	—
Total fixed charges	221	287	337	371	335	340
Non-utility capitalized interest	—	—	—	—	(1)	—
Income from continuing operations before income tax expense, fixed charges and capitalized interest	$ 605	$ 699	$ 488	$ 696	$ 611	$ 735
Total fixed charges, shown above	$ 221	$ 287	$ 337	$ 371	$ 335	$ 340
Increase preferred stock dividend requirements of subsidiaries to a pre-tax amount	—	—	—	—	—	—
Fixed charges for ratio computation	$ 221	$ 287	$ 337	$ 371	$ 335	$ 340
Ratio of earnings to fixed charges and preferred dividends	2.74	2.44	1.45	1.88	1.82	2.16

(a) Excludes income/losses from equity investments.

Exhibit 12.2

Potomac Electric Power Company

	Nine Months Ended September 30, 2012	For the Year Ended December 31, 2011	2010	2009	2008	2007
		(millions of dollars)				
Net income	$ 101	$ 99	$ 108	$ 106	$ 116	$ 125
Income tax expense	38	36	37	76	64	62
Fixed charges:						
Interest on long-term debt, amortization of discount, premium and expense	79	101	101	103	95	86
Other interest	7	10	10	11	11	12
Total fixed charges	86	111	111	114	106	98
Income before income tax expense and fixed charges	$ 225	$ 246	$ 256	$ 296	$ 286	$ 285
Ratio of earnings to fixed charges	2.62	2.22	2.31	2.60	2.70	2.91
Total fixed charges, shown above	$ 86	$ 111	$ 111	$ 114	$ 106	$ 98
Preferred dividend requirements, adjusted to a pre-tax amount	—	—	—	—	—	—
Total fixed charges and preferred dividends	$ 86	$ 111	$ 111	$ 114	$ 106	$ 98
Ratio of earnings to fixed charges and preferred dividends	2.62	2.22	2.31	2.60	2.70	2.91

Exhibit 12.3

Delmarva Power & Light Company

	Nine Months Ended September 30, 2012	For the Year Ended December 31, 2011	2010	2009	2008	2007
			(millions of dollars)			
Net income	$ 56	$ 71	$ 45	$ 52	$ 68	$ 45
Income tax expense	34	42	31	16	45	37
Fixed charges:						
Interest on long-term debt, amortization of discount, premium and expense	36	46	46	45	41	44
Other interest	2	3	2	2	2	2
Total fixed charges	38	49	48	47	43	46
Income before income tax expense and fixed charges	$ 128	$ 162	$ 124	$ 115	$ 156	$ 128
Ratio of earnings to fixed charges	3.37	3.31	2.58	2.45	3.63	2.78
Total fixed charges, shown above	$ 38	$ 49	$ 48	$ 47	$ 43	$ 46
Preferred dividend requirements, adjusted to a pre-tax amount	—	—	—	—	—	—
Total fixed charges and preferred dividends	$ 38	$ 49	$ 48	$ 47	$ 43	$ 46
Ratio of earnings to fixed charges and preferred dividends	3.37	3.31	2.58	2.45	3.63	2.78

Exhibit 12.4

Atlantic City Electric Company

	Nine Months Ended September 30, 2012	For the Year Ended December 31, 2011	2010	2009	2008	2007
			(millions of dollars)			
Net income	$ 36	$ 39	$ 53	$ 41	$ 64	$ 60
Income tax expense	21	33	43	17	30	41
Fixed charges:						
Interest on long-term debt, amortization of discount, premium and expense	54	71	66	69	64	66
Other interest	3	3	3	3	3	3
Total fixed charges	57	74	69	72	67	69
Income before income tax expense and fixed charges	$ 114	$ 146	$ 165	$ 130	$ 161	$ 170
Ratio of earnings to fixed charges	2.00	1.97	2.39	1.81	2.40	2.46
Total fixed charges, shown above	$ 57	$ 74	$ 69	$ 72	$ 67	$ 69
Preferred dividend requirements adjusted to a pre-tax amount	—	—	—	—	—	1
Total fixed charges and preferred dividends	$ 57	$ 74	$ 69	$ 72	$ 67	$ 70
Ratio of earnings to fixed charges and preferred dividends	2.00	1.97	2.39	1.81	2.40	2.44

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: November 5, 2012

/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: November 5, 2012

/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: November 5, 2012

/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: November 5, 2012

/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: November 5, 2012

/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: November 5, 2012

/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: November 5, 2012

/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: November 5, 2012

/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 September 30, 2012, 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.

November 5, 2012	/s/ JOSEPH M. RIGBY Joseph M. Rigby Chairman of the Board, President and Chief Executive Officer
November 5, 2012	/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 September 30, 2012 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.

November 5, 2012	/s/ DAVID M. VELAZQUEZ
	David M. Velazquez President and Chief Executive Officer
November 5, 2012	/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 September 30, 2012, 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.

November 5, 2012	/s/ DAVID M. VELAZQUEZ
	David M. Velazquez President and Chief Executive Officer
November 5, 2012	/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 September 30, 2012, 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.

November 5, 2012	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
November 5, 2012	/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.