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June 18, 2014

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1333 H Street, N.W.
2nd Floor, West Tower
Washington, D.C. 20005

Re: Formal Case No. ______________

Dear Ms. Westbrook-Sedgwick:

Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company and Exelon Energy Delivery Company, LLC, pursuant to the applicable rules of the Public Service Commission of the District of Columbia, hereby submit fifteen (15) courtesy copies of their Joint Application of Exelon Corporation, Pepco Holding, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Richard M. Lorenzo
Partner

Enclosures

cc: Sandra Mattavous-Frye, Office of the People's Counsel

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
THE MERGER OF EXELON CORPORATION,	)	
PEPCO HOLDINGS, INC., POTOMAC ELECTRIC	)	**Formal Case No. ____**
POWER COMPANY, EXELON ENERGY DELIVERY	)	
COMPANY, LLC AND NEW SPECIAL PURPOSE	)	
ENTITY, LLC	)	

VOLUME I of I: **Application and Exhibits of the Joint Applicants**

Direct Testimony and Exhibits of Joint Applicant Witnesses CRANE, RIGBY, O'BRIEN, ALDEN, GAUSMAN, KHOUZAMI, TIERNEY and BUTLER

June 18, 2014

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE MERGER OF EXELON CORPORATION, PEPCO HOLDINGS, INC., POTOMAC ELECTRIC POWER COMPANY, EXELON ENERGY DELIVERY COMPANY, LLC AND NEW SPECIAL PURPOSE ENTITY, LLC	))))))	**Formal Case No. ____**

JOINT APPLICATION OF EXELON CORPORATION, PEPCO HOLDINGS, INC., POTOMAC ELECTRIC POWER COMPANY, EXELON ENERGY DELIVERY COMPANY, LLC AND NEW SPECIAL PURPOSE ENTITY, LLC

Exelon Corporation ("Exelon"), Pepco Holdings, Inc. ("PHI"), Potomac Electric Power Company ("Pepco"), Exelon Energy Delivery Company, LLC ("EEDC"), and New Special Purpose Entity, LLC ("SPE") (collectively, the "Joint Applicants") are filing this Joint Application to obtain the approval of the Public Service Commission of the District of Columbia (the "Commission") pursuant to Sections 34-504 and 34-1001 of the District of Columbia Official Code for a change of control of Pepco to be effected by the merger of PHI with Purple Acquisition Corp. ("Merger Sub"), a wholly-owned subsidiary of Exelon (the "Merger"). In support of the Joint Application, the Joint Applicants state as follows:

I. INTRODUCTION

1. The Merger will combine Exelon's and PHI's electric and gas utilities, which share a focus on safety, operational excellence, environmental stewardship, customer service, employee diversity and a commitment to local communities. Specifically, Pepco and PHI's other utilities will join an organization that includes three outstanding utilities – Baltimore Gas and Electric Company ("BGE"), Commonwealth Edison Company ("ComEd") and PECO Energy Company ("PECO") – with a proven track record of furnishing safe, reliable and efficient energy

delivery services. The Merger will allow Pepco to build upon the expertise of the Exelon utilities in maintaining and enhancing reliability and will offer Pepco additional resources to improve safety and reliability, invest in infrastructure and operational improvements, and deploy innovative technology to help customers reduce their energy use and carbon footprint.

2. Customers in Pepco's service territory will realize direct and traceable financial benefits from an Exelon-funded Customer Investment Fund in the amount of $43 million – equivalent to a value of more than $50 per Pepco electric distribution customer. Of that amount, $14 million would be available for the Customer Investment Fund in the District of Columbia based on the number of customers in the District, with the remainder in the Customer Investment Fund in Maryland. Specifically, at the Commission's discretion and contingent upon the consummation of the Merger, the Customer Investment Fund in the District of Columbia can be used for rate credits, or directed toward assistance for low income customers, energy efficiency initiatives, and/or other programs designed to benefit Pepco's District of Columbia customers in a manner determined by the Commission. As part of the Merger, in the District of Columbia, Exelon also commits that it and its subsidiaries shall, during the ten-year period following the Merger, provide at least an annual average of charitable contributions and traditional local community support that exceeds the 2013 level of $1.6 million. In addition to committing to implement Pepco's current plan to improve system reliability, including its project undertaken in concert with the District to underground certain distribution lines, Exelon is offering a package of firm reliability performance guarantees for Pepco's District of Columbia customers.

3. As discussed in detail in Section VI, *infra*, and in the testimony being submitted herewith, the Customer Investment Fund, enhanced reliability over current levels and other commitments proposed by the Joint Applicants are expected to generate between 907 and 1,281

new jobs in the District of Columbia and have a total economic value to the District of not less than a range of $95.4 million – $133.6 million.

II. DESCRIPTION OF THE JOINT APPLICANTS AND THE OTHER COMPANIES INVOLVED IN THE PROPOSED TRANSACTION

A. Exelon

4. Exelon is a utility services holding company that is incorporated in Pennsylvania, maintains its corporate headquarters at Chase Tower, 10 South Dearborn, 54th Floor, Chicago, Illinois, 60603, and operates through its principal subsidiaries, Exelon Generation Company, LLC ("Exelon Generation"), BGE, ComEd, and PECO. Exelon was formed in 2000 by the merger of PECO and Unicom Corporation, the parent of ComEd. In 2012, Exelon merged with Constellation Energy Group, Inc. ("Constellation"), which added BGE to Exelon's family of energy distribution utilities. Exelon, through its subsidiaries, both generates electricity and delivers electricity and natural gas to customers. Its energy delivery companies serve approximately 7.8 million customers in central Maryland, northern Illinois and southeastern Pennsylvania, as described below. A copy of Exelon's most recent U.S. Securities and Exchange Commission ("SEC") Form 10-K is attached as Exhibit No. 1.

5. EEDC's business address is Chase Tower, 10 South Dearborn, 49th Floor, Chicago, Illinois, 60603. EEDC is the Exelon subsidiary that directly owns 100 percent of the common stock of ComEd and PECO. EEDC also indirectly owns 100 percent of the common stock of BGE through EEDC's subsidiary RF Holdco LLC. RF Holdco LLC is a bankruptcy-remote special purpose entity created specifically to "ring-fence" BGE.

6. SPE is a bankruptcy-remote special purpose entity being created to ring-fence PHI and PHI's energy distribution utilities, including Pepco, as discussed in Section V, *infra.*

7. Exelon's energy delivery business is conducted through PECO, ComEd and BGE. PECO distributes electricity and natural gas within its authorized service territory in southeastern Pennsylvania. PECO is the largest utility in Pennsylvania, providing electric delivery service to approximately 1.6 million customers throughout an area of approximately 2,100 square miles in and around the City of Philadelphia and includes a total population served of approximately 2.4 million people. It supplies natural gas service to more than 500,000 customers outside the city of Philadelphia. ComEd provides electric distribution service to more than 3.8 million customers in northern Illinois and has a service area of approximately 11,400 square miles that includes the City of Chicago. BGE is the largest utility in Maryland, providing electric delivery service to over 1.2 million customers and gas service to over 655,000 customers in a 2,300-square mile territory that encompasses Baltimore City and all or part of ten central Maryland counties. Upon consummation of the merger, another approximately 2 million customers will be added to Exelon's energy delivery business.

8. Exelon's generation business includes its generation fleet, wholesale energy marketing operations and a competitive retail sales business. Exelon's generation business is conducted by Exelon Generation, a wholly-owned subsidiary of Exelon Ventures Company, LLC.[1] Through various subsidiaries, Exelon Generation is also a retail competitive energy provider. Exelon Nuclear, a division of Exelon Generation, operates the largest fleet of nuclear plants in the nation. The fleet consists of 23 reactors at 14 locations in Illinois, Maryland, Nebraska, New Jersey, New York, and Pennsylvania.

[1] Exelon Ventures Company, LLC is scheduled to be dissolved later this year, at which point, Exelon Generation will become a direct subsidiary of Exelon.

B. PHI

9. PHI is a public utility holding company incorporated in Delaware and headquartered at 701 Ninth Street, NW, Washington, D.C., 20068. PHI was created in 2002 as a new holding company to effect the merger of Pepco and the predecessor of the entity that is today Conectiv, LLC ("Conectiv"). As a result of that transaction, PHI owns directly or indirectly three public utility subsidiaries operating in the District of Columbia and three states: Pepco (the District of Columbia and Maryland); Delmarva Power & Light Company ("Delmarva Power") (Delaware and Maryland); and Atlantic City Electric Company ("ACE") (New Jersey) (collectively, the "PHI Utilities"). In addition, PHI, through Pepco Energy Services, Inc. and its subsidiaries (collectively, "PES"), provides energy efficiency and other energy-related services. A copy of PHI's most recent SEC Form 10-K is attached as Exhibit No. 2.

10. As noted above, PHI's energy delivery business is conducted through its three regulated utilities. Pepco, a District of Columbia and Virginia corporation with its headquarters in the District of Columbia, distributes electricity to approximately 264,000 customers in the District of Columbia and 537,000 customers in Montgomery and Prince George's Counties in Maryland. Pepco's service area covers approximately 640 square miles and, as of December 31, 2013, had a population of approximately 2.2 million. Delmarva Power provides electric utility service to approximately 506,000 electric customers in an area encompassing about 6,000 square miles in Delaware and the Eastern Shore of Maryland. Delmarva Power also provides natural gas service to approximately 126,000 customers in a 275 square-mile service area that encompasses a major portion of New Castle County, Delaware. ACE, a New Jersey corporation, serves approximately 545,000 electric customers in a 2,700 square-mile area of southern New Jersey.

11. PES is an energy services company with a focus on energy savings performance contracting, underground transmission and distribution services and integrated power and thermal projects. PES is a licensed retail electricity and natural gas supplier in the District of Columbia. In December 2009, PES notified the Commission that it was discontinuing all of its retail electric and gas marketing activities. PES completed its contractual obligations to its last retail electric customer in June 2013 and served its last retail natural gas customer in May 2014. On May 29, 2014, PES filed with the Commission a request to withdraw its retail electric and natural gas marketing licenses.

C. Merger Sub

12. Merger Sub is a Delaware corporation and a wholly owned subsidiary of Exelon that was formed for the sole purpose of effecting the Merger. Upon completion of the Merger, Merger Sub will be merged into PHI and cease to exist as a separate legal entity.

III. OVERVIEW OF THE PROPOSED TRANSACTION

13. Pursuant to the terms of an Agreement and Plan of Merger (the "Merger Agreement"), a copy of which is attached hereto as Exhibit No. 3, and subject to regulatory approvals and the satisfaction of certain obligations of the parties, PHI will merge with Merger Sub. As the surviving corporation, PHI will become an indirect, wholly-owned subsidiary of Exelon, and PHI's stock will no longer be publicly traded. Specifically, PHI will become the subsidiary of SPE. SPE will be a subsidiary of EEDC, which, as discussed above, owns Exelon's regulated public utility companies. Upon completion of the Merger, PHI's subsidiaries will operate as part of Exelon's holding company system. Charts illustrating the pre-Merger organizational structures of Exelon and PHI and the planned post-Merger corporate organization of the combined company are attached hereto as Exhibit No. 4.

14. Exelon will merge with PHI in an all-cash transaction for approximately $6.8 billion. Upon consummation of the Merger, each PHI shareholder will be entitled to receive $27.25 in cash for each outstanding share of PHI common stock not held by PHI, Exelon, Merger Sub, a PHI or Exelon affiliate, or a dissenting PHI stockholder properly asserting appraisal rights. The common stock of Exelon will be unaffected by the Merger, with each issued and outstanding share thereof remaining outstanding following the Merger. There will be no change in the outstanding debt of Pepco or PHI as a result of the Merger.

15. In connection with the Merger, the Joint Applicants are offering a suite of twelve principal commitments, which is set forth in Exhibit No. 5 hereto. As explained in Sections V and VI, *infra*, and the direct testimony accompanying this Joint Application (*see* Section IX, *infra*), those commitments include direct and traceable financial benefits to Pepco's customers and the District of Columbia.

16. On or about the effective date of the Merger, PHI will be converted from a corporation to a limited liability company or "LLC." Currently, Exelon anticipates that PHI will have a seven-member board of directors with three outside members from the Pepco, ACE, and Delmarva Power service areas and four members who will consist of some combination of officers or directors of Exelon and officers of one or more of Pepco, ACE, and Delmarva Power. The PHI board of directors will select the board of directors of each of Pepco, ACE, and Delmarva Power, and the boards of each of those PHI utilities will choose that utility's officers. Meetings of Exelon's board of directors and other leadership committees will be periodically held in the District of Columbia.

17. Following the Merger, PHI will no longer be a publicly traded company and, as a consequence, a number of corporate functions associated with public status (*e.g.*, investor

relations) will no longer be performed at the PHI level. However, PHI will continue to play substantially the same role in the day-to-day operations of Pepco it does today. To that end, PHI and Pepco will continue to maintain headquarters in Washington, D.C. at Edison Place and the existing operational management structure of PHI will remain substantially the same. PHI's senior management will continue to establish priorities and respond to local conditions as it does today. Pepco's local management will continue to have the authority and responsibility to provide input into the development of Pepco's capital and operating and maintenance ("O&M") expense budgets and implement the approved budgets. While Pepco's budgets will be reviewed by Exelon's CEO and Executive Committee, they would have to be approved by the PHI board of directors.

18. Mr. Christopher M. Crane, the current Chief Executive Officer and President of Exelon, will serve as Chief Executive Officer and President of the combined company following the Merger. PHI's current Chief Executive Officer and President, Mr. Joseph M. Rigby, who previously announced his retirement in January 2014, will retire upon closing of the Merger.

19. Upon consummation of the Merger, Pepco will continue to operate within the District of Columbia as an electric public utility subject to the continuing jurisdiction of the Commission pursuant to the District of Columbia Public Utilities Act, as amended, D.C. Official Code §§ 34-101 *et seq.* and without any reduction in the Commission's existing oversight or authority over Pepco. There will be no loss of regulatory control by the Commission. Pepco will continue to have a board of directors consisting of seven directors following the consummation of the merger in accordance with D.C. Code § 34-404. In addition, the Joint Applicants are confirming their ongoing commitment to comply with all applicable District of Columbia and federal requirements related to affiliate transactions. Thus, the Merger will not adversely impact

any of the day-to-day operations of Pepco. Indeed, as set forth in more detail below, the Merger will enhance the capabilities of Pepco to fulfill its obligations to provide safe, adequate and reliable service to its retail customers in the District of Columbia.

IV. REQUESTED COMMISSION APPROVALS AND LEGAL STANDARDS

A. Change Of Control

20. The Commission should approve the proposed Merger because it is in the public interest in that, among other things, it will provide direct and traceable financial benefits to the public and Pepco's customers in the District of Columbia. Under D.C. Code § 34-504 (formerly § 43-704), "[n]o public utility shall ... purchase the property of any other public utility for the purpose of effecting a consolidation until the Commission shall have determined and set forth in writing that said consolidation will be in the public interest, nor until the Commission shall have approved in writing the terms upon which said consolidation shall be made."

21. In Formal Case No. 951, the Commission defined the standard as whether "a merger 'taken as a whole [is] consistent with the public interest.'"[2] The public interest test is satisfied upon a showing that the Merger will "benefit the public rather than merely leave it unharmed."[3] In balancing "the interests of a utility's shareholders and investors with the interests of ratepayers and the community," the Commission evaluates "the financial stability of the merging companies, and what effect approval or disapproval of this merger will have on future investment." In other words, will "[t]he companies' ability to continue to attract capital … have

[2] Formal Case No. 951, Order No. 11075 at 20, quoting FERC Docket No. RM96-6-000, Order No. 592 (Dec. 18, 1996), at 12-13.

[3] *Id.* at 17.

an impact on both the quality of future electric service in the District, as well as the rates District consumers will pay in the future."[4]

22. The expected benefits to the shareholders and investors must be shared with the public. The Commission explained that the "merger must produce a direct and traceable financial benefit to ratepayers."[5] As such, "any savings that result must be shared with the ratepayers, and be shared in such a proportion that ratepayers are compensated for the risks inherent in the companies' decision to merge."[6]

23. In Formal Case No. 951, the Commission analyzed the propriety of the merger with respect to: (1) the customers, shareholders and financial health of the utilities standing alone and as merged, and the local economy; (2) utility management and administrative operations; (3) the safety and reliability of services; (4) risks associated with nuclear operations; (5) the Commission's ability to regulate the new utility effectively; and (6) competition in the local utility market.[7]

24. In Formal Case No. 1002, the last electric utility merger proceeding considered by the Commission, the Commission identified 15 issues that it would consider to determine whether the merger was in the public interest, many of which issues address areas of interest identified by the Commission in Formal Case No. 951.[8] The Joint Applicants have submitted with the Application a draft issues list attached as Exhibit No. 6, which was derived using the issue list from Formal Case No. 1002. The Joint Applicants' proposed list includes 14 of the 15

[4] *Id.* at 17.

[5] *Id.* at 18.

[6] *Id.* at 18.

[7] *Id.* at 20.

[8] Formal Case No. 1002, Order No. 12189 at P.12 (2001).

designated issues from that case, plus two additional issues.[9] The first issue concerns the risks, costs, and benefits associated with Exelon's nuclear operations, which was an issue in Formal Case No. 951. The second additional issue relates to the impact, if any, of the Merger on plans to underground Pepco's distribution feeders in the District of Columbia.

25. As explained in Sections V and VI, *infra*, and in the direct testimony attached hereto, the proposed Merger is in the public interest in that it properly balances the interests of Pepco's shareholders and investors with the interests of customers and the community, promotes Pepco's ability to continue to attract capital, and allows the merged entities to provide safe, adequate and reliable service to the District of Columbia. The Merger produces direct and traceable benefits for Pepco's District of Columbia customers.

B. 15 D.M.C.R. § 104.1(g) Statement

26. Rule 104.1(g) of the Commission's Rules of Practice and Procedure, 15 D.C.M.R. § 104.1(g), requires the Joint Applicants to indicate whether the proceeding should be considered a "rate case" or "other investigation" for purposes of Section 34-912 of the District of Columbia Code.

27. Joint Applicants do not propose any change in Pepco's current base rates that recently were approved in Formal Case No. 1103 in Order No. 17424. Thus, this proceeding is not a general or special rate case. During the pendency of and as a result of this proceeding, Pepco's rates and services in the District of Columbia are expected to remain unchanged. District of Columbia customers will continue to receive cost effective, reliable service from Pepco. The

[9] The Joint Applicants propose eliminating Issue No. 14: "What authority will the Commission have over the issuance of securities by the parent companies?"

Joint Applicants therefore submit that the proceeding should be considered an "other investigation" for purposes of Section 34-912 of the District of Columbia Code.

28. It is well-settled law that a "rate case" is "a proceeding, including a formal hearing, that results in a Commission order fixing any of the rates of a utility."[10] In *Washington Gas Light*, the District of Columbia Court of Appeals decided that proceedings which "may have an incidental or indirect effect on rates" are not rate cases.[11] The DC Court of Appeals rejected the notion that a case that has some nexus to the setting of utility rates would require that the case be designated a rate case. While in future rate proceedings the impacts of the Merger on customer rates will appropriately be an issue, here the Joint Applicants are not requesting, nor is it appropriate, to adjust Pepco's rates. Where, as here, the reasonableness of the rates set by this Commission less than three months ago are not an issue and the Joint Applicants are not seeking approval to transfer the adopted rates to another company, it is contrary to established law to designate this proceeding as a rate case.

29. While in Formal Case No. 1002 the Commission determined that merger proceeding to be a rate case, the holding there is inconsistent with *Washington Gas Light*. In Formal Case No. 1002, the Commission never made a determination whether the proceeding was a general or special rate case, but rather found that "the merger's rate implications are sufficiently related to the Commission's rate making authority to the *Washington Gas Light* standards."[12] The Commission highlighted, among other things, that future rates as well as rate

[10] *Washington Gas Light Co. v. Public Serv. Comm'n,* 455 A.2d 384, 389 (D.C. 1982) ("*Washington Gas Light*").

[11] *Id. See also Office of People's Counsel v. Public Serv. Comm'n,* 572 A.2d 410, 413-14 (D.C. 1990); *Watergate East, Inc. v. Public Serv. Comm'n,* 662 A.2d 881, 890 n.9 (D.C. 1995).

[12] Formal Case No. 1002, Order No. 12189 at P.11.

increase requests will be lower than otherwise would be the case absent the merger.[13] The D.C. Court of Appeals held that "Congress did not intend that the definition of term 'rate case' be within the Public Service Commission's discretion" and determined that "a proper construction of [§ 34-912] within the context of the public utilities statute reveals that 'rate case' refers to general or special rate cases."[14]

C. Affiliated Interest Transactions

30. Both PHI and Exelon have service company subsidiaries that make available to their respective operating company affiliates a broad range of accounting, financial, legal and other services. At Exelon, employees that perform core utility functions are employed by the Exelon utilities, while employees that provide administrative and technical support services are employed by Exelon Business Services Company ("EBSC"). Given the operational structure of PHI and the PHI Utilities, the PHI Service Company employs personnel who provide services in areas that would be considered core utility functions for Exelon and its utilities. It is expected that EBSC will continue to provide administrative and technical support services for various Exelon companies and will also provide similar services to PHI and its subsidiaries. PHI Service Company will remain in place for an undetermined period of time during post-merger integration. As integration proceeds and systems and functions are combined in phases, Pepco may receive different services from EBSC and PHI Service Company until all shared corporate support functions are consolidated under EBSC.

31. As described in more detail in the direct testimony of Carim V. Khouzami, pursuant to the Commission's regulations, within thirty (30) days of the consummation of the

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[13] *Id.*

[14] *Washington Gas Light Co.*, 455 A.2d at 390.

Merger, the Joint Applicants will file with the Commission the cost allocation manual to be used for the assignment and/or allocation of costs arising from Pepco's participation in Exelon's existing General Services Agreement ("GSA").[15] A copy of the GSA is attached as Exhibit No. 7. The GSA provides that the services furnished by the EBSC to Pepco will be billed at the EBSC's cost, and direct charges of those costs will be made wherever possible. If a cost cannot be assigned directly to a utility, it is allocated on the basis of the allocation factors/methodologies identified in an attachment to the GSA. After the merger, the Commission will have the same access to EBSC's books and records and the same transparency into EBSC as it has with PHI Service Company.

32. Exelon Generation is currently an active participant in the Power Supply Procurement Process for Standard Offer Service ("SOS") and following the closing of the Merger intends to continue to participate in the process. Pepco will continue to provide SOS to its customers in the District consistent with the provisions of 15 D.C.M.R._§ 4100 *et seq.* Joint Applicants further acknowledge the District of Columbia's Affiliate Code of Conduct, 15 D.C.M.R. § 3900 *et seq.*, and the requirement that they have in place procedures to prevent preferences and the improper flow of information between Pepco and PHI (including PHI's unregulated affiliates). Exelon agrees that it and its subsidiaries and affiliates will be bound by those procedures to the extent applicable following the closing of the Merger.

V. IMPACT OF THE PROPOSED MERGER ON SERVICE, RATES, JOBS AND LOCAL COMMUNITIES

33. The Joint Applicants are committed to providing adequate, efficient, safe and reliable electric service, and the Merger will not diminish in any way Pepco's current plan to

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[15] 15 D.C.M.R. §3904.3.

improve system reliability, including the implementation of its undergrounding project as currently planned. In fact, the Merger will convene six distribution utilities under one structure and provide a clearinghouse of best practices which will lead to operational and infrastructure improvements, strengthen emergency response capabilities, and facilitate the use of innovative technology to improve service delivery and customer service. Accordingly, District of Columbia customers will be positioned to enjoy even a higher quality of service than Pepco has committed to maintain and enhance, all of which will lead to additional direct and traceable financial benefits to the District of Columbia and Pepco's customers.

34. In addition, and to express in concrete terms the Joint Applicants' commitment to improve the reliability of Pepco's electric transmission and distribution systems, the Joint Applicants are proposing several specific reliability guarantees for Pepco's District of Columbia customers, as explained by Mr. Mark F. Alden, subject to certain return on equity penalties for non-compliance that are described by Mr. Khouzami. These reliability guarantees show a continuing commitment to maintaining safe and reliable transmission and distribution service, consistent with the public interest standard set forth in Order No. 12395.

35. Pepco's proposed reliability guarantees applicable to electric utility service are summarized below. As explained in the direct testimony of Mr. Alden, compliance with each of these proposed guarantees will be determined on the basis of a three-year historical average (2018-2020) to account for any abnormal weather variability that may occur in a given year.

(a) <u>System Average Interruption Frequency Index ("SAIFI")</u>: By 2020, Exelon will guarantee that Pepco's SAIFI in its District of Columbia operational area does not exceed 0.54 interruptions. Compliance will be measured using the Commission's current methodology for calculating SAIFI and inclusion or exclusion of storm events.

(b) System Average Interruption Duration Index ("SAIDI"): By 2020, Exelon will guarantee that Pepco's SAIDI in its District of Columbia operational area does not exceed 107 minutes. Compliance will be measured using the Commission's current methodology for calculating SAIDI and inclusion or exclusion of storm events.

36. Pepco's rates, rules and regulations and the terms and conditions of service in effect prior to the Merger will not change as a result of the Merger. In fact, Pepco distribution customers will realize direct and traceable financial benefits because, as previously noted, Pepco will provide tangible customer benefits with an aggregate value of $14 million in the District of Columbia, or more than $50 per distribution customer. The disposition of the District of Columbia's share of the Customer Investment Fund is at the Commission's discretion, subject, of course, to the consummation of the Merger. For example, the Commission might determine to use the District of Columbia's share of the Customer Investment Fund to provide a bill credit to customers. Alternatively, the Commission might choose, in a separate proceeding, to utilize the Fund to assist low income customers, to strengthen energy efficiency measures or to support other programs designed to benefit Pepco's customers. As explained in the direct testimony of Mr. Khouzami, the Joint Applicants also expect that the Merger will enable them to achieve efficiencies and cost savings in the future, an allocable portion of which will accrue to Pepco. Those economies will help to offset the increase in the costs of providing regulated electric distribution and transmission service and, thus, are expected to give rise, over time, to lower rates than otherwise would be the case, providing direct and traceable financial benefits to District of Columbia customers.

37. The Merger also will not have any adverse impact on Pepco's rates for two primary reasons. First, as noted previously, there will be no change in the outstanding debt of PHI or Pepco as a result of the Merger. Pepco will not incur or assume any debt, including the

provision of guarantees or collateral support, directly related to the Merger. Second, Pepco will not seek rate recovery of any acquisition premium or "goodwill" associated with the Merger or of merger transaction costs incurred by the Joint Applicants or their subsidiaries.

38. Pepco is well-positioned to continue to provide safe, reliable and efficient service to its customers based on its existing capitalization and credit rating. Pepco's capital structure will not change as a result of the Merger. The Joint Applicants have also committed to implement robust ring-fencing measures for at least five years following completion of the Merger, which provide further assurances that Pepco will continue to have direct access to credit markets at reasonable rates. Those ring-fencing provisions include creating a bankruptcy-remote special purpose entity as a subsidiary of EEDC to hold the equity interests in PHI, as described in detail in the direct testimony of Mr. Khouzami.[16]

39. The Merger will result in some reductions in force. For example, certain positions in the managerial and administrative ranks will no longer be necessary as duplicative positions are consolidated. However, in the two years following consummation of the Merger, Exelon commits to ensure no net reduction in the employment levels at Pepco due to involuntary attrition resulting from the Merger integration process and to provide current and former Pepco employees with compensation and benefits at least as favorable in the aggregate as the compensation those employees received immediately before the date of the Merger Agreement. Moreover, Exelon commits to ensure that Pepco honors its existing collective bargaining agreements. Notably, District of Columbia Local 1900 of the International Brotherhood of

[16] The time period that the special purpose entity interposed between PHI and EEDC will remain in place is not limited.

Electrical Workers recently agreed to a three-year contract extension and agrees that the Merger is in the best interest of Pepco and its employees.

40. Pepco plays a vital role in the District of Columbia's local communities through the financial support of numerous civic and charitable organizations. Pepco's commitment to remain a good corporate citizen and an active member of the communities it serves will continue unabated after the Merger. To that end, during the ten-year period following consummation of the Merger, Exelon and its subsidiaries have committed to provide at least an annual average of charitable contributions and traditional local community support in the District of Columbia that exceeds the 2013 level of $1.6 million. Pepco has made contributions in the District of Columbia to support local organizations and initiatives, as well as groups that have a national focus, such as the Trust for the National Mall and the MLK Memorial, and this is not expected to change. Moreover, Pepco will maintain its low income customer assistance programs and supplier diversity programs pursuant to current requirements and commitments.

VI. BENEFITS OF THE MERGER

41. By combining six outstanding utilities in a single holding company structure, the Merger will create the Mid-Atlantic region's premier electric and natural gas distribution utility, serving approximately ten million utility customers. The Joint Applicants recognize that Pepco has a long history serving the District of Columbia starting with its formation in the late 19th century. There have been many changes during these past 118 years. Pepco has successfully responded to these changes, including more recently with the 2001 reorganization in which it became a subsidiary of PHI. With continuing changes in the industry, this Merger allows PHI and Pepco to become part of a combined entity that will possess the management, employee experience, technical expertise, retail customer base, and financial resources to grow and succeed

in an increasingly challenging environment for energy distribution companies. The combination will allow PHI and Pepco to maintain local control while at the same time provide resources allowing it to consistently deliver safe, adequate and reliable service at just and reasonable rates. The Merger also will allow PHI and Pepco to become part of a company with vast experience in, among other things, renewable energy, energy efficiency and demand response. The sharing of resources and best practices among the combined companies, as well as their comparable business models, will produce direct and traceable financial benefits to District of Columbia customers in several important ways.

a. Increased Scale and Scope; Diversification. There are many benefits that will be derived from the increased scale, scope and diversification of the combined company, including improved service, reliability, operational flexibility and financial stability for all Exelon and PHI public utility subsidiaries. As explained by both Mr. Crane and Mr. O'Brien in their direct testimonies, Exelon will provide additional resources and support to the PHI Utilities leading to an enhanced overall customer experience, while allowing each of the PHI Utilities, including Pepco, to maintain its local identity.

b. Maintain Local Control. The Merger will not result in multiple tiers of management that have to be penetrated to access decision-makers in the organization. PHI and Pepco will continue to maintain their headquarters in Washington, D.C. The Commission and stakeholders in the District of Columbia will enjoy the same access to Pepco and PHI personnel after the merger. In addition, Pepco's Regional President, who works closely with the operational side of the business, will continue to provide a strong local connection and maintain relationships within the District of Columbia.

c. **Enhanced Reliability.** Exelon and PHI share a strong commitment to enhancing reliability and recognize the importance of reliable service to the residents of the District of Columbia and the Commission. While maintaining its strong local control, the Merger will facilitate and build upon Exelon's expertise in transmission and distribution operations and allow Pepco to leverage best practices shared across the Exelon enterprise. The Merger also will allow Pepco to take advantage of the deployment of Exelon utility crews during major storm events. PECO and ComEd have consistently achieved outstanding performance in all major metrics for transmission and distribution reliability and, since joining the Exelon family, BGE's reliability performance has substantially improved, with 2013 being its best ever year. The combined companies will work to improve Pepco's current level of reliability, as evidenced by the reliability guarantees offered by the Joint Applicants and their commitment to implement Pepco's undergrounding project.

Previous Exelon mergers have built upon the resources of combining companies to strengthen operating utilities, leading to significant improvements in reliability metrics. Most recently, following the March 2012 merger with Constellation and its utility subsidiary, BGE, Exelon leveraged best practices and reprioritized planned capital projects in Maryland to improve reliability. As explained by Mr. Alden, these performance improvements included an almost 32% decline (from 2012 to 2013) in the average time to restore service to BGE customers who experienced a sustained interruption. Moreover, these improvements in performance were achieved without increasing either BGE's capital or operating expenditures. The Joint Applicants make the same commitment to improve reliability without an increase in Pepco's reliability-related capital and O&M budgets.

d. Enhanced Expertise in Renewable Energy, Energy Efficiency, and Demand Response. The combined company is expected to be able to draw upon the intellectual capital, technical expertise and experience of a deeper and more diverse workforce, with particular skills in renewable energy solutions and energy savings programs. Exelon is an industry leader in adopting renewable energy technology. For example, Exelon's generation companies own and operate nearly 1,300 megawatts ("MW") of wind generation and approximately 240 MW of utility-scale solar generation, while its retail companies have installed more than 173 MW in distributed generation for customers and supplied renewable electricity to more than 82,300 customers. Under Exelon's 2020 Plan, each Exelon utility has taken a variety of additional actions to reduce its own carbon footprint, such as reducing internal building electricity use through aggressive building modernization efforts, using clean technologies and alternative fuels in fleet vehicles and delivering customer energy efficiency savings through PECO's and ComEd's award winning "Smart Ideas" programs. Through these combined efforts, Exelon achieved and surpassed its ambitious Exelon 2020 goal of reducing its carbon footprint by 17.5 million metric tons of greenhouse gas emissions seven years early, in 2013.

Just as Pepco has done, each of the Exelon utilities is also installing smart meters for residential and commercial customers to provide customers increased information regarding their usage and to enable them to make smarter energy choices. Accordingly, as the distribution grid platform continues to evolve, the merged company should be better able to invest in and deploy new processes and technologies, including innovations that support the efforts of the District of Columbia's Sustainable Energy Utility and the Exelon utilities' successful energy efficiency and demand response programs.

e. Commitment to Employees. Exelon has committed that, upon approval of this Joint Application as described herein and for a period of two years after consummation of the Merger, there will be no net reductions due to involuntary attrition as a result of the Merger integration process in the employment levels of Pepco. Further, consistent with the terms of the Merger Agreement, Exelon has committed to honor all Pepco collective bargaining agreements, including all terms and conditions of those agreements. Also consistent with the Merger Agreement, Exelon has agreed that for at least two years after the closing, Exelon will provide current and former Pepco employees compensation and benefits that are at least as favorable in the aggregate as the compensation and benefits provided to those employees immediately before the Merger.

f. Synergies, Efficiencies and Cost Savings. The Merger will have no immediate effect on customer rates, rules, or terms of service. However, the Merger will confer immediate direct benefits of $14 million, or more than $50 for each Pepco distribution customer in the District of Columbia. The Joint Applicants are also confident that the Merger will generate synergies and result in overall aggregate cost saving opportunities for the combined company. The synergies that will accrue to Pepco over time should, at least in part, offset the increasing cost of providing regulated distribution and transmission utility service and, thereby, mitigate the need for or reduce the size of future rate increases that would have otherwise been requested absent the Merger.

On a broader scale, the Joint Applicants requested Susan F. Tierney, Ph.D. of the Analysis Group to evaluate the likely economic impact of the Merger on the jurisdictions served by the PHI utilities. Using widely-accepted analytic techniques, Dr. Tierney concluded that the total economic value to the District of Columbia of: (1) the Customer Investment Fund; and (2) the increase in reliability over current levels to which Exelon is committing approximates $95.4-133.6 million, on a net present value basis (2014), over the period 2015-2020, depending on how the Commission utilizes the Customer Investment Fund. In addition, Dr. Tierney found that the Merger could create up to 1,281 new jobs in the District of Columbia.

The realization of the benefits described above will have no adverse impact on the continued abilities of Pepco to provide safe and adequate utility service to its customers, nor will it in any way affect the Commission's jurisdiction over the adequacy and reliability of customer service provided by Pepco. To the contrary, the sharing of best practices will benefit utility operations and customer service at all levels. In addition, the rules, regulations, terms and conditions of service that are currently effective for retail customers in Pepco's service territories will not change as a result of Commission approval of this Joint Application and the completion of the Merger. Pepco will continue to be fully subject to, and accountable for, the safeguards and standards promulgated by the Commission to foster safe, adequate and reliable service.

g. **Strong Leadership In Local Communities.** The Joint Applicants have deep commitments to the communities they serve. As part of Exelon, Pepco will continue to play an important role in the economic growth of the District of Columbia and remain a significant employer and responsible corporate citizen. In his direct testimony, Calvin G. Butler, Jr. describes the types of community commitments made by the Exelon companies and their employees and the civic and charitable activities of BGE after its merger with Exelon. Exelon is committed to the District of Columbia.

As a further indication of its continuing commitment to the local communities served by Pepco, for the decade following consummation of the Merger, Exelon and its subsidiaries have agreed to provide at least an annual average of charitable contributions and traditional local community support in the District of Columbia that exceeds the 2013 level of $1.6 million. By working to provide increasingly reliable service, to attain operational excellence and to seek deployment of new technologies that benefit their customers, Pepco will continue to be a strong and productive leader in contributing to the District of Columbia's economic growth.

VII. IMPACT ON COMPETITION

42. The Merger will not have any adverse competitive effects on either the wholesale market or the District of Columbia's retail energy markets. Each of the PHI Utilities, including Pepco, has divested all of its generation facilities and purchases power only pursuant to requirements contracts to serve its default service load and must-take contracts with Qualifying Facilities entered into under the Public Utility Regulatory Policies Act of 1978 or pursuant to Commission-approved programs such as net energy metering in the District of Columbia. Additionally, all of the PHI Utilities' transmission assets are under the operational control of PJM Interconnection, L.L.C. ("PJM") under PJM's Open Access Transmission Tariff. For these reasons, the Merger will not have any impact on wholesale competition and does not raise any market power concerns.[17]

43. Exelon, under the name Constellation, provides competitive retail service in Washington, D.C. and it plans to continue to do so post-merger. In 2009, PES notified the Commission that it was discontinuing all of its retail electric and gas marketing activities and, effective June 2013 and May 2014, respectively, completed its contractual obligations to retail electric and natural gas customers in the District of Columbia. In addition, as noted in Section II above, PES, on May 29, 2014, filed a notice of discontinuance of its existing licenses to provide

[17] *See* Docket No. EC14-96-000, Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Sections 203(A)(1) and 203(A)(2) of the Federal Power Act, in which the Federal Energy Regulatory Commission is considering market power issues for this transaction related to ownership of generation and the impact on wholesale markets.

retail and natural gas service with the Commission. Moreover, as discussed in Section IV.C above, Exelon will be bound by District of Columbia's Affiliate Code of Conduct and will ensure that Pepco has in place standards and procedures to prevent preferences and the improper flow of information between Pepco and Exelon's subsidiaries. As a consequence, the Merger will not have any impact on retail competition.

VIII. IMPACT OF NUCLEAR OPERATIONS

44. The Commission in Formal Case No. 951 addressed the financial risks associated with nuclear operations. Mr. Crane explains that Exelon is a leader in nuclear safety and has been recognized for the world class performance of its nuclear generating facilities. In this proceeding, there is no risk to Pepco, its customers or the local community attributable to Exelon's ownership of nuclear generation because, as part of the transaction, a special purpose entity will be established that will ring-fence PHI and its subsidiary utilities from financial risks, including those associated with the costs of accidents, nuclear waste disposal or decommissioning.

IX. SUPPORTING TESTIMONY

45. With this Joint Application, the Joint Applicants are submitting the written testimony and supporting exhibits of eight witnesses, which, subject to possible supplementation in response to positions, inquiries and issues set forth in the filings by other parties or in interim orders of the Commission, will comprise the Joint Applicants' case-in-chief:

Christopher M. Crane is Exelon's President and Chief Executive Officer. Mr. Crane describes the proposed Merger and summarizes the substantial benefits that it will produce. He also explains the factors that make Exelon and PHI a good fit. (Joint Applicants (A))

Joseph M. Rigby is PHI's President and Chief Executive Officer. He describes the shared vision and values of PHI and Exelon and explains why the Merger is in the best interests of the PHI utilities, their customers and the communities they serve. (Joint Applicants (B))

Denis P. O'Brien is Senior Executive Vice President of Exelon and Chief Executive Officer of Exelon Utilities. Mr. O'Brien describes how the PHI utilities will be managed following the Merger, including how the operational structure, governance principles and delegation of authority will maintain substantial local control. Mr. O'Brien also discusses the experience of integrating utility operations following the merger of PECO and Unicom that formed Exelon and the merger of Exelon and Constellation that brought BGE into the Exelon family of utility companies. Finally, Mr. O'Brien describes Exelon's commitments regarding employment levels and employee compensation. (Joint Applicants (C))

Mark F. Alden is the Vice President of Utility Oversight and Integration for Exelon. Mr. Alden explains Exelon's commitment to enhancing reliability in the District of Columbia and discusses Exelon's track record of service excellence. (Joint Applicants (D))

William M. Gausman is Senior Vice President, Strategic Initiatives of PHI. Mr. Gausman describes the current reliability commitments of Pepco to its District of Columbia customers. (Joint Applicants (E))

Carim V. Khouzami is a Senior Vice President of BGE and Exelon's Chief Integration Officer. Until recently assuming the position of Chief Integration Officer, he served as BGE's Chief Financial Officer and Treasurer. Mr. Khouzami discusses the financial impacts of the Merger, the merger accounting principles that will apply, the measures

Exelon is committing to implement to ring-fence the PHI utilities and the financial penalty Exelon is proposing in the event Pepco fails to meet Exelon's reliability commitments. Additionally, Mr. Khouzami provides an overview of the planned integration of Exelon and PHI and describes the estimated merger savings and costs to achieve those savings. (Joint Applicants (F))

Susan F. Tierney, Ph.D. is a Senior Advisor with the Analysis Group. Dr. Tierney discusses the quantitative and qualitative economic benefits to Pepco customers and the District of Columbia from the Merger. (Joint Applicants (G))

Calvin G. Butler, Jr. is BGE's Chief Executive Officer. Mr. Butler discusses Exelon's approaches to electric system reliability, charitable giving, community involvement and supplier diversity and explains how BGE has been able to benefit from Exelon's programs in these areas since merging with Exelon in 2012. (Joint Applicants (H))

X. ADDITIONAL SUPPORTING DATA

46. The Commission's Rules of Practice and Procedure do not prescribe the information that is required to be set forth in an application seeking approval and authorization of a merger of this kind. This Joint Application is in full compliance with the Commission's general filing requirements. In the event, however, the Commission determines that this Joint Application has failed to conform in any respect to the requirements of its Rules, the Applicants hereby respectfully request a waiver of such filing requirements pursuant to Rule 146.1, 15 D.C.M.R. § 146.1 (1998).

47. The Joint Applicants are attaching as Exhibit No. 8 a proposed schedule and respectfully request that the Commission issue a decision on the merits by the end of April 2015.

XI. OTHER REQUIRED APPROVALS

48. In addition to approval by the Commission, several other regulatory approvals will be required before the Merger can be concluded. These include expiration of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as well as approvals from the Federal Energy Regulatory Commission ("FERC"), the Federal Communications Commission, the Delaware Public Service Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities and the Virginia State Corporation Commission.

49. The Merger also is subject to the affirmative majority vote of PHI's shareholders.

XII. SERVICE

50. Pursuant to Rule 110.4, 15 D.C.M.R. § 110.4, Exelon and PHI hereby designate the following individuals for the service list in this proceeding:

Paul R. Bonney
Senior Vice President & Deputy General Counsel
Exelon Corporation
100 Constellation Way
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paul.bonney@exeloncorp.com

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51. Parties are also requested to serve documents on the following attorneys as a courtesy:

Kevin C. Fitzgerald
Executive Vice President & General Counsel
Wendy E. Stark
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ntravers@loeb.com

XIII. CONCLUSION

52. For all of the reasons set forth in and supported by this Joint Application, the Merger will provide direct and traceable financial benefits for customers, the District of Columbia and the Mid-Atlantic region. Therefore, the Merger is in the public interest and satisfies the legal requirements for approval by this Commission.

WHEREFORE, the Joint Applicants respectfully request that the Commission grant approval of the proposed Merger and any other approvals as it may determine are necessary in order for the Merger to be lawfully consummated.

Respectfully submitted,

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Washington, D.C.
June 18, 2014

Counsel for the Joint Applicants

VERIFICATION

STATE OF ILLINOIS)
)
COUNTY OF COOK)

I, Darryl M. Bradford, am Senior Vice President and General Counsel of Exelon Corporation, parent of Exelon Energy Delivery Company, LLC (collectively, the Exelon Applicants); that I am authorized to make this Verification on behalf of the Exelon Applicants; that the foregoing filing was prepared under my direction and supervision; and that the contents with respect to the Exelon Applicants are true and correct to the best of my knowledge, information and belief

Darryl M. Bradford
Senior Vice President and General Counsel
Exelon Corporation, parent of Exelon Energy
Delivery Company, LLC

Sworn and subscribed before me this 17th day of June, 2014

Sharon Brookins
Notary Public

My Commission expires Nov. 8, 2014

OFFICIAL SEAL
SHARON BROOKINS
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:11/08/14

VERIFICATION

STATE OF DELAWARE)
)
COUNTY OF NEWCASTLE)

I, David M. Velazquez, am Executive Vice President of applicant Pepco Holdings, Inc., and President and Chief Executive Officer of applicant Potomac Electric Power Company (collectively, the PHI Applicants); that I am authorized to make this Verification on behalf of the PHI Applicants; that the foregoing filing was prepared under my direction and supervision; and that the contents with respect to the PHI Applicants are true and correct to the best of my knowledge, information and belief

David M. Velazquez
Executive Vice President
Pepco Holdings, Inc.

President and Chief Executive Officer
Potomac Electric Power Company

Sworn and subscribed before me this 12th day of June, 2014

Kathy Ann S. Martin
Notary Public

My Commission expires February 1, 2015

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Joint Application of Exelon Corporation, Pepco Holding, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC., has been served this 18th day of June, 2014, on:

Sandra Mattavous-Frye
People's Counsel
Office of the People's Counsel
1133 15th Street, N.W.
Suite 500
Washington, D.C. 20005

Richard M. Lorenzo

EXHIBIT 1

EXHIBIT 1

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2013

OR

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

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

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

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

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

COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

	Large Accelerated	Accelerated	Non-Accelerated	Small Reporting Company
Exelon Corporation	✓			
Exelon Generation Company, LLC			✓	
Commonwealth Edison Company			✓	
PECO Energy Company			✓	
Baltimore Gas and Electric Company			✓	

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

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2013 was as follows:

Exelon Corporation Common Stock, without par value	$ 26,430,683,706
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None

The number of shares outstanding of each registrant's common stock as of January 31, 2014 was as follows:

Exelon Corporation Common Stock, without par value	857,419,806
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,904
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2014 Annual Meeting of Shareholders and the Commonwealth Edison Company 2014 information statement are incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company and Baltimore Gas and Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations	
1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended

Other Terms and Abbreviations

Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste

Other Terms and Abbreviations

LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal

Other Terms and Abbreviations

Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, (c) ITEM 8. Financial Statements and Supplementary Data: Note 22 and (d) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO and BGE, in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Generation

Generation's integrated business consists of its owned and contracted electric generating facilities and investments in generation ventures that are marketed through its leading customer-facing activities. These customer-facing activities include, wholesale energy marketing operations and its competitive retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO. Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE's principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

Operating Segments

See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Merger with Constellation Energy Group, Inc.

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail customers. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable energy and other energy-related products and services, and engages in natural gas exploration and production activities.

Generation is a public utility under the Federal Power Act and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities (including Generation, which is a public utility as FERC defines that term) and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Significant Acquisitions

***Antelope Valley Solar Ranch One*.** On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation’s renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation’s owned capacity within the ERCOT power market by 720 MWs.

See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisitions.

Significant Dispositions

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger, for net proceeds of approximately $371 million, which resulted in a pre-tax loss of $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2013, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [(a)]	
Nuclear	17,263
Fossil	12,165
Renewable (including Hydroelectric) [(b)]	3,710
Owned generation assets	33,138
Long-term power purchase contracts [(c)]	9,426
Investment in CENG [(d)]	1,999
Total generating resources	44,563

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Includes equity method investment in certain generating facilities.
(c) Excludes contracts with CENG. See Long-Term Power Purchase Contracts table in this section for additional information.
(d) Generation owns a 50.01% interest in CENG, a joint venture with EDF. See ITEM 2. PROPERTIES—Generation and Note 25—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions, representing the different geographical areas in which Generation's customer-facing activities are conducted and where Generation's generating resources are located.

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 37% of capacity).
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 34% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 8% of capacity).
- New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 12% of capacity).
- Other Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,263 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership) and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon's financial statements relative to its proportionate ownership interest in each unit. Generation's nuclear generating stations are all operated by

Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2013 and 2012, electric supply (in GWh) generated from the nuclear generating facilities was 57% and 53%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Constellation Energy Nuclear Group, Inc.

Generation also owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns and operates a total of five nuclear generating facilities on three sites, Calvert Cliffs, Ginna and Nine Mile Point. CENG's ownership share in the total capacity of these units is 3,998 MW. See ITEM 2. PROPERTIES for additional information on these sites.

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The Nuclear Operating Services Agreement will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG and, in any event, payable upon settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if

Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation's obligations under this indemnity.

CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation currently has an agreement under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the nuclear plant output owned by CENG, and EDF will purchase on a unit contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon the completion of the Put Option Agreement transaction.

Currently, Exelon and Generation account for its investment in CENG under the equity method of accounting. The transfer of the operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize its equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation's balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon's and Generation's results of operations. See Note 5—Investment in CENG of the Combined Notes to Consolidated Financial Statements for additional information regarding CENG.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2013 and 2012, the nuclear generating facilities operated by Generation achieved capacity factors of 94.1% and 92.7%, respectively. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the rigorous maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2013, the NRC categorized Dresden units 2 and 3, LaSalle unit 2, and Clinton in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column as of December 31, 2013, which is the highest performance band. On January 1, 2014, Dresden units 2 and 3 returned to the Licensee Response Column. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Executive Overview.

Licenses. Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek and Three Mile Island Unit 1. Additionally, PSEG has 40-year operating licenses from the NRC and has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [(a)]	Current License Expiration
Braidwood [(b)]	1	1988	2026
	2	1988	2027
Byron [(b)]	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden [(c)]	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick [(d)]	1	1986	2024
	2	1990	2029
Oyster Creek [(c)(e)]	1	1969	2029
Peach Bottom [(c)]	2	1974	2033
	3	1974	2034
Quad Cities [(c)]	1	1973	2032
	2	1973	2032
Salem [(c)]	1	1977	2036
	2	1981	2040
Three Mile Island [(c)]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Braidwood Units 1 and 2 and Byron Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued a renewed operating licenses.
(d) In June 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation expects to apply for and obtain approval of license renewals for the remaining nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Nuclear Waste Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities in on-site storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2013, Generation had approximately 59,900 SNF assemblies (14,400 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island. Clinton and Three Mile Island will currently lose full core reserve, which is when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core, in 2015 and 2023, respectively. Dry cask storage will be in operation at Clinton and is expected to be in operation at Three Mile Island prior to the closing of their respective on-site storage pools. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 22 of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation is currently utilizing on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its Class A LLRW, which represent 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut. Generation has received NRC approval for its Peach Bottom and LaSalle stations that will allow storage at these sites of LLRW from its remaining stations with limited capacity. Generation now has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. During 2012, Generation entered into a six year contract to ship Class B and Class C LLRW to Texas. The terms of the agreement will provide for disposal of all current Class B and Class C LLRW stored at the stations, as well as the waste generated during the term of the agreement. Although Texas started accepting waste for disposal in 2012, the Texas site is curie limited (3.9 million curies for 15 years). With this limit, the annual facility volume will not match industry production of activated hardware, and on-site storage is expected to be required for the Generation boiling water reactors. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 22 of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES—Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Notes 3, 11 and 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation's estimated ARO liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2013 was $208 million and $114 million, respectively. As of December 31, 2013, NDT funds set aside to pay for these obligations were $436 million.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 15,875 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Keystone, Conemaugh, and Wyman; (2) ownership interests through equity method investments in Colver, Malacha, Safe Harbor, and Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on these wind project entities. Generation's fossil and renewable generating stations are all operated by Generation, with the exception of Colver, Conemaugh, Keystone, LaPorte, Malacha, Safe Harbor, Sunnyside and Wyman, which are operated by third parties. In 2013 and 2012, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 15% and 12%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Generation and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS —Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, respectively. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run's current license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. However, the stations will continue to operate under annual licenses until FERC takes action on the 46-year license applications. Refer to Note 3—Regulatory Matters for additional information.

Insurance. Generation maintains business interruption insurance for its renewable projects, and delay in start-up insurance for its renewable projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES—Generation.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2013:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic [(a)]	16	2016 - 2032	799
Midwest	7	2015 - 2022	1,734
New England	14	2014 - 2020	1,291
ERCOT	5	2014 - 2026	1,489
Other Regions	11	2014 - 2030	4,113
Total	53		9,426

	2014	2015	2016	2017	2018
Capacity Expiring (MW)	1,300	1,705	651	1,337	100

(a) Excludes contracts with CENG.

Fuel

The following table shows sources of electric supply in GWh for 2013 and 2012:

	Source of Electric Supply [a]	
	2013	2012
Nuclear	142,126	139,862
Purchases—non-trading portfolio [b]	69,791	91,994
Fossil	30,785	27,760
Renewable	6,420	4,079
Total supply	249,122	263,695

(a) Represents Generation's proportionate share of the output of its generating plants.
(b) Includes purchases pursuant to Generation's PPA with CENG. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

The fuel costs for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2016. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2020. All of Generation's enrichment requirements have been contracted through 2018. Contracts for fuel fabrication have been obtained through 2018. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation may buy power to meet the energy demand of its customers, including ComEd, PECO and BGE. Generation sells electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation’s customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation’s purchases may be for more than the energy demanded by Generation’s customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. Generation actively manages these physical and contractual assets in order to derive incremental value. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties.

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to relatively greater commodity price risk in 2014 and beyond for which a larger portion of its electricity portfolio may be unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity, including purchased power from CENG. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation’s hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation’s efforts. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. Additionally, the corporate risk management group and Exelon’s RMC monitor the financial risks of the wholesale and retail power marketing activities. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2013, Generation's short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases (a)	REC Purchases (b)	Transmission Rights Purchases (c)	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$1,378
2015	367	110	13	—	490
2016	284	76	2	—	362
2017	223	25	2	—	250
2018	112	3	2	—	117
Thereafter	414	3	32	—	449
Total	$ 1,812	$ 334	$ 76	$ 824	$3,046

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements Generation purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties. CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. This purchase agreement will continue to be effective under the Master Agreement discussed above, except that if the put option under the Master Agreement is exercised, then the EDF PPA will be transferred to Generation upon the completion of the Put Option Agreement transaction. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase from CENG at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 25 of the Combined Notes to Consolidated Financial Statements for more details on this arrangement.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation's estimated capital expenditures for 2014 are as follows:

(in millions)	
Nuclear fuel (a)	$ 900
Production plant	900
Renewable energy projects	300
Uprates	150
Maryland commitments	100
Other	50
Total	$2,400

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to a diverse base of residential, commercial and industrial customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities, and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd's retail service territory has an area of approximately 11,400 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 2.7 million. ComEd has approximately 3.8 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2014 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd's kWh deliveries and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. ComEd's highest peak load occurred on July 20, 2011, and was 23,753 MWs; its highest peak load during a winter season occurred on January 6, 2014, and was 16,514 MWs.

Retail Electric Services

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from a competitive electric generation supplier. The customers' choice activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense. ComEd's cost of electric supply is passed without markup directly through to those customers not served by a competitive electric generation supplier and those rates are subject to adjustment monthly to recover or refund the difference between ComEd's actual cost of electricity delivered and the amount included in rates. For those customers that choose a competitive electric generation supplier, ComEd acts as the billing agent but does not record revenues or expenses related to the electric supply. ComEd remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on customer switching to competitive electric generation suppliers, and Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process and for additional information.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd's obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kWs continues for all customers who do not choose a competitive electric generation supplier or who choose to return to ComEd after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kWs or greater, as this group of customers has previously been declared competitive. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

Energy Infrastructure Modernization Act (EIMA). Since 2011, ComEd's distribution rates are established through a performance-based rate formula pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Electric Distribution Rate Cases. The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). On September 27, 2013, the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

On May 24, 2011, the ICC issued an order in ComEd's 2010 electric distribution rate case (2010 Rate Case), which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery service revenue requirement and a 10.5% rate of return on common equity. The order has been appealed to the Court by several parties. On May 16, 2013, the Court dismissed as moot the appeals of the ICC's order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electric distribution rate cases.

Procurement-Related Proceedings. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As required by EIMA, in February 2012 the IPA completed procurement events for energy and REC requirements for the June 2013 through December 2017 period. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's procurement plans. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's energy commitments.

Continuous Power Interruption. The Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan with the ICC. On December 5, 2012, the ICC approved ComEd's revised AMI deployment plan. On June 5, 2013, the ICC issued an interim Order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

Energy Efficiency Programs. As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In December 2010, the ICC approved ComEd's second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013—May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, any additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal ("RFP") process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Construction Budget

ComEd's business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Based on PJM's RTEP, ComEd has various construction commitments, as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2014 is $1,775 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's operations. PECO is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 4.0 million. PECO provides electric distribution service in an area of approximately 1,900 square miles, with a population of approximately 3.9 million, including approximately 1.5 million in the City of Philadelphia. PECO provides natural gas distribution service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 501,000 customers.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution service in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," which are rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

PECO's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO's highest peak load occurred on July 22, 2011 and was 8,983 MW; its highest peak load during winter months occurred on January 7, 2014 and was 7,148 MW.

PECO's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. PECO's highest daily natural gas send out occurred on January 7, 2014 and was 760 mmcf.

Retail Electric Services

PECO's retail electric sales and distribution service revenues are derived pursuant to rates regulated by the PAPUC. Pennsylvania permits competition by competitive electric generation suppliers for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2013, there were 87 competitive electric generation suppliers serving PECO customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was 531,500 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 68% of PECO's retail kWh sales for the year ended December 31, 2013. Customers that choose a competitive electric generation supplier are not subject to rates for PECO's electric supply procurement costs and retail transmission service charges. PECO presents on customer bills its electric supply Price to Compare, which is updated quarterly, to assist customers with the evaluation of offers from competitive electric generation suppliers.

Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or PECO's financial position. PECO's cost of electric supply is passed directly through to default service customers without markup and those rates are subject to adjustment at least quarterly to recover or refund the difference between PECO's actual cost of electricity delivered and the amount included in rates through the GSA. For those customers that choose a competitive electric generation supplier, PECO acts as the billing agent but does not record revenues or purchase power expense related to this electric supply. PECO remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service.

Procurement Proceedings. PECO's electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs. PECO entered into contracts with PAPUC-approved bidders, including Generation, as part of its DSP I competitive procurements conducted since June 2009 for its default electric supply beginning January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. In September 2012, PECO completed its last competitive procurement for electric supply under its first DSP Program, which expired on May 31, 2013.

On October 12, 2012, the PAPUC approved PECO's second DSP Program, which was filed with the PAPUC in January 2012. The plan outlines how PECO is purchasing electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO is procuring electric supply through five competitive procurements for fixed price full requirements contracts of two years or less for the residential and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

The second DSP Program also includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from competitive electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission's decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC, which was approved without modification on August 15, 2013. In total, PECO currently expects to spend up to $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Programs. PECO's PAPUC-approved Phase I EE&C plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan sets forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report was filed with the PAPUC on November 15, 2013.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until late 2013. On February 28, 2013, the PAPUC approved PECO's three-year EE&C Phase II plan that was filed with the PAPUC on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO's natural gas sales and distribution service revenues are derived through natural gas deliveries at rates regulated by the PAPUC. PECO's purchased natural gas cost rates, which represent a significant portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates without markup through the PGC.

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. At December 31, 2013, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, representing approximately 13% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 19% of PECO's mmcf sales for the year ended December 31, 2013. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

Procurement Proceedings. PECO's natural gas supply is purchased from a number of suppliers primarily under long-term firm transportation contracts for terms of up to three years in accordance with its annual PAPUC PGC settlement. PECO's aggregate annual firm supply under these firm transportation contracts is 34 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO's 2013-2014 heating season planned supplies.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

PECO's business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. PECO, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2014 is $625 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project net of expected SGIG DOE reimbursements.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE's operations. BGE is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of BGE's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE serves an estimated population of 2.8 million in its 2,300 square mile combined electric and gas retail service territory. BGE provides electric distribution service in an area of approximately 2,300 square miles and gas distribution service in an area of approximately 800 square miles, both with a population of approximately 2.8 million, including approximately 621,000 in the City of Baltimore. BGE delivers electricity to approximately 1.2 million customers and natural gas to approximately 655,000 customers.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE's authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are not exclusive and are perpetual. With respect to natural gas distribution service, BGE's authorizations consist of charter rights, a perpetual state-wide franchise grant, and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

BGE's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. BGE's highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on January 7, 2014 and was 6,526 MW.

BGE's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. BGE's highest daily natural gas send out occurred on February 5, 2007 and was 840 mmcf.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE’s electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This adjustment allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period (referred to as “revenue decoupling”). Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits affected customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Retail Electric Services

BGE’s retail electric sales and distribution service revenues are derived from electricity deliveries at rates regulated by the MDPSC. As a result of the deregulation of electric generation in Maryland effective July 1, 2000, all customers can choose a competitive electric generation supplier. While BGE does not sell electric supply to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance services. Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has minimal impact on electric revenue net of purchased power expense or BGE’s financial position. At December 31, 2013, there were 73 competitive electric generation suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 399,000, representing 32% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 61% of BGE’s retail kWh sales for the year ended December 31, 2013.

BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE’s wholesale power supply costs and include an administrative fee. The administrative fee includes a commercial and industrial shareholder return component and an incremental cost component. Bidding to supply BGE’s market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years.

BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

Electric Distribution Rate Cases. In December 2010, the MDPSC issued an abbreviated electric rate order authorizing BGE to increase electric distribution rates for service rendered on or after December 4, 2010 by no more than $31 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period beginning in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns the authorized rate of return.

On July 27, 2012, BGE filed an application for an increase to its electric base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE’s 2012 electric rate case for increases in annual distribution service revenue of $81 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%.

On May 17, 2013, BGE filed an application for an increase to its electric base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE’s 2013 electric distribution rate case authorizing an increase in annual distribution service revenue of $34 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%. The approved electric distribution rate became effective for services rendered on or after December 13, 2013.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In August 2010, the MDPSC approved BGE's $480 million SGIP, which includes deployment of a two-way communications network, 2 million smart electric and gas meters and modules, new customer pricing programs, a new customer web portal and numerous enhancements to BGE operations. Also, in April 2010, BGE entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, BGE has been awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives. The SGIG funding is being used to reduce significantly the rate impact of those investments on BGE customers. As of December 31, 2013, BGE has billed the entire $200 million grant to the DOE.

Energy Efficiency Programs. BGE's energy efficiency programs include a CFL program, retrofit programs, an energy efficient appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs as well as a customer surcharge to recover the associated costs. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE's conservation programs for implementation in 2012 through 2014.

Natural Gas

BGE's natural gas sales are derived pursuant to a MBR mechanism that applies to customers who buy their gas from BGE. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimum impact on gas revenue net of purchased power expense or BGE's financial position. At December 31, 2013, there were 41 competitive natural gas suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing fuel from a competitive natural gas supplier was approximately 172,000 representing 26% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 54% of BGE's retail mmcf sales for the year ended December 31, 2013.

BGE must secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed price contracts are recovered under the MBR mechanism and are not subject to sharing. BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements. BGE's current pipeline firm transportation entitlements to serve its firm loads are 362 mmcf per day.

BGE's current maximum storage entitlements are 284 mmcf per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,055 mmcf and a daily capacity of 332 mmcf,
- a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 6 mmcf and a daily capacity of 6 mmcf, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 546 mmcf and a daily capacity of 85 mmcf.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods. BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

Natural Gas Distribution Rate Cases. In December 2010, the MDPSC issued a rate order authorizing BGE to increase the gas distribution base revenue requirement for service rendered on or after December 4, 2010 by no more than $9.8 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010.

On July 27, 2012, BGE filed an application for an increase to its gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE's 2012 gas rate case for increases in annual distribution service revenue of $32 million. The electric distribution rate increase was set using an allowed return on equity of 9.60%.

On May 17, 2013, BGE filed an application for an increase to its gas base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE's 2013 natural gas distribution rate case authorizing an increase in annual distribution service revenue of $12 million. The gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved natural gas distribution rate became effective for services rendered on or after December 13, 2013.

Construction Budget

BGE's business is capital intensive and requires significant investments primarily in electric and natural gas distribution and electric transmission facilities to ensure the adequate capacity, reliability and efficiency of its system. BGE, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. BGE's most recent estimate of capital expenditures for plant additions and improvements for 2014 is approximately $600 million, which includes capital expenditures related to the SGIP net of expected SGIG DOE reimbursements.

ComEd, PECO and BGE

Transmission Services

ComEd, PECO and BGE provide unbundled transmission service under rates approved by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC's open access transmission policy promulgated in Order No. 888, ComEd, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff), operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. ComEd, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO default service customers are charged for retail transmission services through a rider designed to recover PECO's PJM transmission network service charges and RTEP charges on a full and current basis in accordance with the 2010 electric distribution rate case settlement.

The transmission rate in the PJM Open Access Transmission Tariff under which PECO incurs costs to serve its default service customers and earns revenue as a transmission facility owner is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for wholesale transmission service.

BGE's transmission rates are established based on a formula that was approved by FERC in April 2006. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Employees

As of December 31, 2013, Exelon and its subsidiaries had 25,829 employees in the following companies, of which 8,602 or 33% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 (a)	IBEW Local 614 (b)	Other CBAs (c)	Total Employees Covered by CBAs	Total Employees
Generation	1,690	100	1,973	3,763	11,973
ComEd	3,487	—	—	3,487	5,895
PECO	—	1,254	—	1,254	2,418
BGE	—	—	—	—	3,303
Other (d)	71	—	27	98	2,240
Total	5,248	1,354	2,000	8,602	25,829

(a) A separate CBA between ComEd and IBEW Local 15, ratified on October 10, 2012, covers approximately 32 employees in ComEd's System Services Group. Generation's and ComEd's separate CBAs with IBEW Local 15 were extended through February 28, 2014.

(b) 1,254 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire on March 31, 2015. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires on November 3, 2016 and covers 107 employees.

(c) During 2013, Generation finalized a CBA with the Security Officer union at Oyster Creek, which will expire in 2016. Additionally, during 2013, three other 3-year agreements were negotiated: Power, IBEW Local 614, which will expire in 2016; New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016. During 2012, Generation finalized CBAs with the Security Officer unions at Byron, Clinton and TMI, which expire between 2015 and 2016. During 2011, Generation finalized CBAs with the Security Officer unions at Braidwood, Dresden, LaSalle and Quad Cities, which expire between 2014 and 2015. During 2010, Generation entered into a CBA with the Security Officer union at Limerick, which expires in 2014. Additionally, during 2009, a 5-year agreement was reached with Oyster Creek Nuclear Local 1289, which expires in 2015.

(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the U.S. EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon board of directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon board has delegated to its corporate governance committee authority to oversee Exelon's compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including, Exelon's climate change and sustainability policies and programs, and Exelon 2020, Exelon's comprehensive business and environmental plan, as discussed in further detail below. The Exelon board has also delegated to its generation oversight committee authority to oversee environmental, health and safety issues relating to Generation. The respective boards of ComEd, PECO and BGE, which each include directors who also serve on the Exelon board, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to reduce substantially air pollution from power plants. Advanced emission controls for SO_2 and NOx have been installed at all of Generation's co-owned bituminous coal-fired units.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR and CAIR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the U.S. EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation's power generation facilities discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the impact to Exelon of state permitting agencies' administration of the Phase II rule implementing Section 316(b) of the Clean Water Act.

Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Solid and Hazardous Waste

The CERCLA provides for immediate response and removal actions coordinated by the U.S. EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the U.S. EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with a U.S. EPA-directed cleanup, may voluntarily settle with the U.S. EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO and BGE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the U.S. EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's, PECO's and BGE's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2014 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $40 million, consisting of $33 million, $6 million and $1 million at ComEd, PECO and BGE, respectively.

Generation's environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2013, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

In addition, Generation, ComEd, PECO and BGE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial position.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, and as reported by the Intergovernmental Panel on Climate Change in their Fifth Assessment Report Summary for Policy Makers issues September 2013. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represent the majority of Exelon's direct GHG emissions in 2013, although only a small portion of Exelon's electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity at its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is, or may become, subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States has not yet ratified the United Nations Kyoto Protocol, which was extended at the 2012 meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18). The Kyoto Protocol now requires participating developed countries to cap GHG emissions at certain levels until 2020, when the new global agreement on emissions reduction is scheduled to become effective. This new global agreement for GHG emissions reductions was agreed to only in concept during the COP18, with a timeline for establishing the global targets by 2015. On November 22, 2013, at the 2013 COP 19 held in Warsaw, Poland, participating countries further agreed to provide their "intended nationally determined contributions" by the first quarter of 2015 in preparation for formally setting global target in 2015. The other major issues discussed at COP 19 were demands from developing countries for increased climate finance, and for a new mechanism to help especially vulnerable nations cope with unavoidable "loss and damage" resulting from climate change. Developed countries, which had previously promised to mobilize a total of $100 billion a year by 2020, refused to set a quantified interim goal for ramping up climate finance.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue, including the enactment of federal climate change legislation. It is highly uncertain whether Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. In June 2013, the White House released the President’s Climate Action Plan which consists of a wide variety of executive actions targeting GHG reductions, preparing for the impacts of climate change and showing leadership internationally; but the plan did not directly trigger any new requirements or legislative action.

The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama’s June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President’s memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program, which must be approved pursuant to the applicable legislative and/or regulatory process in each RGGI state, the regional RGGI CO2 budget would be reduced, starting in 2014, from its current 165 million ton level to 91 million tons, with a 2.5 percent reduction in the cap level each year between 2015-2020. Included in the new program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO2 allowances available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, rising 2.5 percent thereafter to account for inflation). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, the Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor’s GHG reduction goals. At this time, the only requirements imposed by the state of Illinois are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

On December 18, 2009, Pennsylvania issued the state’s final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change released its climate action plan on August 27, 2008, recommending that the state begin implementing 42 greenhouse gas reduction strategies. One of the Plan’s policy recommendations, to adopt science-based regulatory goals to reduce Maryland’s GHG emissions, was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA). The law requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It directed the MDE to work with other state agencies to prepare an implementation plan to meet this goal. The implementation plan was published in October of 2013. Maryland targeted electricity consumption reduction goals required under the “Empower Maryland” program, and mandatory State participation in the recently updated and enhanced RGGI Program are listed as that sector’s contribution in the plan. The plan also advocates raising the renewable portfolio standard requirement from 22% by 2022 to 25% by 2022.

Exelon's Voluntary Climate Change Efforts. In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon's low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

With the announcement in 2008 of Exelon 2020, Exelon set a voluntary goal to reduce, offset or displace more than 15.7 million metric tonnes of GHG emissions per year by 2020. Exelon updated that goal in 2012 following the Constellation merger to account for the integration of former Constellation GHG goals. The updated Exelon 2020 goal is to reduce, offset or displace more than 17.5 million metric tonnes of GHG emissions by 2020. The Exelon 2020 goal encompasses three broad areas of focus: reducing or offsetting Exelon's own carbon footprint (with the year the asset/operations were acquired by Exelon as the baseline), helping customers and communities reduce their GHG emissions, and offering more low-carbon electricity in the marketplace. Exelon has been maintaining strong performance towards achieving the goal and anticipates reaching the 17.5 million tons of annual abatement well before 2020.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. As previously described, Illinois, Pennsylvania and Maryland have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

The Illinois Settlement Legislation required that procurement plans implemented by electric utilities include cost-effective renewable energy resources or approved equivalents such as RECs in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers by June 1, 2008, increasing to 10% by June 1, 2015, with a goal of 25% by June 1, 2025. Utilities are allowed to pass-through any costs from the procurement of these renewable resources or approved equivalents subject to legislated rate impact criteria. As of December 31, 2013, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act became effective for PECO on January 1, 2011, following the expiration of PECO's transition period. During 2013, PECO was required to supply approximately 4.0% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) through May 31, 2013 and subsequently 4.5% beginning June 1, 2013 and continuing through May 31, 2014. PECO was also required to supply 6.2% of electric energy generated from Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, respectively, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2013, 8.2% was required from Tier 1 renewable sources, including at least 0.25% derived from solar energy, and 2.5% from Tier 2 renewable sources. The wholesale suppliers that supply power to the state's utilities through the SOS procurement auctions have the obligation, by contract with those utilities, to comply with and provide its proportional share of the RPS requirements.

Similar to ComEd, PECO and BGE, Generation's retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation's renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 13, 2014

Exelon

Name	Age	Position	Period
Crane, Christopher M.	55	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O'Brien, Denis P.	53	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Gillis, Ruth Ann M.	59	Executive Vice President, Exelon	2008 - Present
		Chief Administrative Officer, Exelon	2010 - Present
		President, Exelon Business Services Company	2005 - Present
		Chief Diversity Officer, Exelon	2009 - 2012
Von Hoene Jr., William A.	60	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
		Executive Vice President and General Counsel, Exelon	2008 - 2009
		Senior Vice President, Exelon Business Services Company	2004 - 2009
Thayer, Jonathan W.	42	Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	51	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
		Chief Executive Officer, Essent Trading International	2004 - 2009
DesParte, Duane M.	50	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012

Name	Age	Position	Period
Pacilio, Michael J.	53	President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - Present
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
Nigro, Joseph	49	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	51	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid-Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	47	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Aiken, Robert	47	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011
		Vice President of International Accounting, Constellation Energy Commodities Group	2007 - 2009

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Donnelly, Terence R.	53	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
		Senior Vice President, Transmission and Distribution, ComEd	2007 - 2009
Trpik Jr., Joseph R.	44	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
		Vice President & Assistant Corporate Controller, Exelon Business Services Company	2007 - 2009
		Vice President and Assistant Corporate Controller, Exelon	2004 - 2009

Name	Age	Position	Period
Jensen, Val	58	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O'Neill, Thomas S.	51	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
		Senior Vice President, New Business Development, Generation; Senior Vice President, New Business Development, Exelon	2009 - 2009
		Vice President, New Plant Development, Generation	2007 - 2009
Marquez Jr., Fidel	52	Senior Vice President, Governmental and External Affairs, Exelon	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
		Vice President of External Affairs and Large Customer Services, ComEd	2007 - 2009
Brookins, Kevin B.	52	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
Anthony, J. Tyler	49	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	41	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012
		Manager of Accounting, ComEd	2008 - 2009

PECO

Name	Age	Position	Period
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	50	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	48	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010

Name	Age	Position	Period
Webster Jr., Richard G.	52	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	54	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	53	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	67	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
		Associate General Counsel, Exelon	2008 - 2009
Bailey, Scott A.	37	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Woerner, Stephen J.	46	Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - Present
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
		Senior Vice President, Gas and Electric Operations and Planning, BGE	2007 - 2009
Khouzami, Carim V.	38	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2013 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2011 - 2013
		Executive Director, Investor Relations, Constellation Energy	2009 - 2011
		Director, Corporate Strategy and Development, Constellation Energy	2008 - 2009
Butler, Calvin	44	Senior Vice President, Regulatory and External Affairs, BGE	2013 - Present(a)
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010

Name	Age	Position	Period
Case, Mark D.	52	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Dodson, Carol A.	49	Vice President, Customer Operations, BGE	2013 - Present
		Chief Customer Officer, BGE	2013 - Present
		Vice President, Utility Oversight, BSC	2012 - 2013
		Vice President, Engineering and Project Management, BGE	2012 - 2012
		Senior Vice President, Asset Management Services, BGE	2009 - 2012
Gahagan, Daniel P.	60	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	41	Vice President and Controller, BGE	2012 - Present
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010

(a) On February 12, 2014, Kenneth W. DeFontes Jr., President and Chief Executive Officer at BGE announced his retirement from BGE on February 28, 2014. Effective March 1, 2014, Calvin G. Butler Jr. will become Chief Executive Officer of BGE and an executive officer of Exelon and Stephen J. Woerner will become President and continue as Chief Operating Officer of BGE.

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond the Registrant’s control. Management of each Registrant regularly meets with the Chief Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants’ businesses, and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the finance and risk committee and audit committees of the Exelon board of directors and the ComEd, PECO and BGE boards of directors. In addition, the generation oversight committee of the Exelon board of directors’ evaluates risks related to the generation business. The risk factors discussed below may adversely affect one or more of the Registrants’ results of operations and cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that may adversely affect its performance or financial condition in the future.

The Registrants’ most significant risks arise as a consequence of: (1) Generation’s position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. The Registrants’ major risks fall primarily under the following categories:

- ***Market and Financial Risks.*** Exelon’s and Generation’s market and financial risks include the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the prices of natural gas and coal, which drive the prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation’s output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

- ***Regulatory and Legislative Risks.*** The Registrants' regulatory and legislative risks include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon's and Generation's financial performance may be adversely affected by changes that could affect Generation's ability to sell power into the competitive wholesale power markets at market-based prices. In addition, potential regulation and legislation regarding climate change and renewable portfolio standards could increase the pace of development of wind energy facilities, which could put downward pressure in some markets on wholesale market prices for electricity from Generation's nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Also, regulatory actions in Illinois, Pennsylvania or Maryland could materially lower returns for ComEd, PECO and BGE, respectively.
- ***Operational Risks.*** The Registrants' operational risks include those risks inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon's ability to protect and grow shareholder value. Additionally, the operating costs of ComEd, PECO and BGE, and the opinions of customers and regulators of ComEd, PECO and BGE, are affected by those companies' ability to maintain the reliability and safety of their energy delivery systems.
- ***Risks Related to the Merger with Constellation and the Pending Master Agreement between Generation and CENG.*** As a result of the merger with Constellation that closed on March 12, 2012, Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals from the July 29, 2013 Master Agreement between Exelon, Generation and subsidiaries of Generation with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. Exelon and Generation are subject to the risks that integration of CENG's nuclear fleet may not achieve anticipated results, and that Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Risks

Generation is exposed to depressed prices in the wholesale and retail power markets, which may negatively affect its results of operations and cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. As such, Generation's earnings and cash flows are therefore subject to variability as spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels: The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, may displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The continued tepid economic environment and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation’s markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, may often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. The risk of increased supply in excess of demand is heightened by continued or increased RPS mandates or other subsidies, including ITCs and PTCs.

Retail Competition: Generation’s retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In an environment of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition can adversely affect overall gross margins and profitability in Generation’s retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon’s and Generation’s results of operations and cash flows, and such impacts could be emphasized given Generation’s concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon’s and Generation’s ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon’s and Generation’s results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs which may be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon’s and Generation’s results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and may negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation’s retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Unstable Markets. The wholesale spot markets remain evolving markets that vary from region to region and are still developing practices and procedures. Problems in or the failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially exposed to emerging technologies that may over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (Exelon, Generation, ComEd, PECO and BGE)

Some of these technologies include, but are not limited to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices. Such developments could lower the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors may decrease the value of NDT funds and employee benefit plan assets and increase the related employee benefit plan obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which may fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments may increase Generation's funding requirements to decommission its nuclear plants. A decline in the market value of the pension and other postretirement benefit plan assets will increase the funding requirements associated with Exelon's pension and other postretirement benefit plan obligations. Additionally, Exelon's pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements may also increase the costs and funding requirements of the obligations related to the pension and other postretirement benefit plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the investments with the NDT funds and benefit plan assets, and unable to manage the related benefit plan liabilities, their results of operations, cash flows and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect the Registrants' financial condition, results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad can adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2013, approximately 30%, or $2.5 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants' credit facilities as of December 31, 2013. See Note 13 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in competitive energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon's and Generation's results of operations and cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation's business is subject to credit quality standards that may require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

ComEd’s operating agreement with PJM contains collateral provisions that are affected by its credit rating and market prices. If certain wholesale market conditions exist and ComEd were to lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required under the PJM operating agreement to provide collateral in the forms of letters of credit or cash, which may have a material adverse effect upon its liquidity. Collateral posting will generally increase as market prices rise and decrease as market prices fall. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if ComEd were downgraded, it could experience higher borrowing costs as a result of the downgrade.

PECO’s and BGE’s operating agreements with PJM and their natural gas procurement contracts contain collateral provisions that are affected by their credit ratings. If certain wholesale market conditions exist and PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the form of letters of credit or cash, which may have material adverse effects upon their liquidity. PECO’s and BGE’s collateral requirements relating to their natural gas supply contracts are a function of market prices. Collateral posting requirements for PECO and BGE with respect to these contracts will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if PECO or BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or ComEd, PECO, or BGE in particular, has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as “ringfencing”) may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ringfencing measures, the credit ratings of ComEd, PECO or BGE could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

See Liquidity and Capital Resources—Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants' cash flows.

Generation's financial performance may be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. Coal, natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, coal, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that may negatively affect the results of operations for Generation.

Generation's risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation's asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions may have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products in the wholesale markets and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. The proportion of hedged positions in its power generation portfolio may cause volatility in Generation's future results of operations.

Financial performance and load requirements may be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's wholesale output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results may be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States that may significantly change the tax rules applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation would be on its results of operations and cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon's 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the like-kind exchange position. The litigation could take three to five years including appeals, if necessary.

As of December 31, 2013, if the IRS is successful in its challenge to the like-kind exchange position, Exelon's potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after-tax charge of $87 million to Exelon's and ComEd's results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1 and 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns may lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors may decrease Generation's, ComEd's, PECO's and BGE's results from operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

ComEd's, PECO's and BGE's current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's and PECO's costs of purchased power are charged to customers without a return or profit component. BGE's SOS rates charged to customers recover BGE's wholesale power supply costs and include an administrative fee which includes a shareholder return component and an incremental cost component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas can result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for ComEd, PECO and BGE. In addition, any challenges by the regulators or ComEd, PECO and BGE as to the recoverability of these costs could have a material effect on the Registrants' results of operations and cash flows. Also, ComEd's, PECO's and BGE's cash flows can be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd's, PECO's and BGE's results from operations and cash flows. Generation's customer supply activities face economic downturn risks similar to Exelon's utility businesses, such as lower volumes sold and increased expense for uncollectible customer balances. As Generation increases its customer supply footprint, economic downturn impacts could negatively affect Generation's results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The effects of weather may impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms may stress ComEd's, PECO's and BGE's transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions may have detrimental effects on ComEd's, PECO's and BGE's results of operations and cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage can impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position may become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants' statement of financial position. Specifically, long-lived assets account for 59%, 49%, 61%, 66% and 75% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2013. In addition, the Registrants have significant balances related to unamortized energy contracts. See Notes 4 and 10 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

Exelon and Generation have investments in certain generating plant projects, including the CENG nuclear joint venture with a carrying value of $1.9 billion as of December 31, 2013. These investments were acquired in the March 2012 Constellation transaction, and were recorded as equity method investments on the balance sheet at fair value on the merger date as part of purchase accounting. Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such issues indicate an other than temporary decline in value. Such impairment could have a material adverse impact on Exelon's and Generation's results of operations.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records a non-cash impairment charge to expense if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Such an impairment could have a material adverse impact on Exelon's results of operations.

Exelon and ComEd had approximately $2.6 billion of goodwill recorded at December 31, 2013 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off, reducing equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd's fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's and ComEd's results of operations.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS —Critical Accounting Policies and Estimates and Notes 7, 8 and 10 of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants' businesses are capital intensive, and their assets may require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants' businesses are capital intensive and require significant investments by Generation in energy generation and by ComEd, PECO and BGE in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and may require significant expenditures to operate efficiently. The Registrants' results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants may incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant's results of operations, cash flows and financial position. In connection with Exelon's 2001 corporate restructuring, Generation assumed certain of ComEd's and PECO's rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd's or PECO's results of operations, cash flows and financial position.

Generation's business may be negatively affected by competitive electric generation suppliers. (Exelon and Generation)

Because retail customers where Generation serves load can switch from their respective energy delivery company to a competitive electric generation supplier for their energy needs, planning to meet Generation's obligation to provide the supply needed to serve Generation's share of an electric distribution company's default service obligation is more difficult than planning for retail load before the advent of retail competition. Before retail competition, the primary variables affecting projections of load were weather and the economy. With retail competition, another major factor is retail customers switching to or from competitive electric generation suppliers. If fewer of such customers switch from its retail load serving counterparties than Generation anticipates, the load that Generation must serve will be greater than anticipated, which could, if market prices have increased, increase Generation's costs (due to its need to go to market to cover its incremental supply obligation) more than the increase in Generation's revenues. If more customers from its retail load serving counterparties switch than Generation anticipates, the load that Generation must serve will be lower than anticipated, which could, if market prices have decreased, cause Generation to lose opportunities in the market.

Regulatory and Legislative Risks

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations and financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's, ComEd's, PECO's and BGE's operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant of rules changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could adversely affect their results of operations, cash flows and financial position.

Regulatory and legislative developments related to climate change and RPS may also significantly affect Exelon's and Generation's results of operations, cash flows and financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

Generation may be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working, and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 60% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on 1) FERC's continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC's RFP for new gas-fired generation in Maryland. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority. On December 31, 2013, Generation submitted its triennial application seeking reauthorization to sell at market-based rates in the Northeast region (including PJM, ISO-NY and ISONE). Generation's previous submission seeking reauthorization to sell at market-based rates was accepted by FERC on June 22, 2011 for the PJM region.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis that unfolded during 2008. Dodd-Frank ushers in a brand new regulatory regime applicable to the over-the-counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Generation has determined that it will conduct its commercial hedging business as an end user in a manner that does not require registration as a swap dealer or major swap participant.

Notwithstanding the foregoing, Generation will still face additional regulatory obligations under Dodd-Frank, including some reporting requirements, clearing some additional transactions that it would otherwise enter into over-the-counter, and having to adhere to position limits. More fundamentally, however, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swaps market to decrease substantially. Dodd-Frank may require up to $1 billion of additional collateral requirements at Generation, to be met with cash rather than letters of credit in a price stressed environment. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

Generation's affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation's physical asset base within the ComEd, PECO and BGE service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd, PECO and BGE and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with ComEd, PECO and BGE and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs incurred by ComEd, PECO or BGE, including transactions between Generation, on the one hand, and ComEd, PECO or BGE, on the other hand, regardless of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements can subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant may otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee may be limited by the financial resources of the transferee. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd's, PECO's and BGE's respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which may introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd, PECO or BGE to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd's, PECO's and BGE's results of operations, cash flows and financial position. See Note 3 of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations and cash flows of Generation, ComEd, PECO and BGE. (Exelon, Generation, ComEd, PECO and BGE)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation, ComEd, PECO and BGE, especially if timely cost recovery is not allowed. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, ComEd, and PECO. For additional information, see ITEM 1. BUSINESS "Environmental Regulation-Renewable and Alternative Energy Portfolio Standards."

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd, PECO and BGE would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2013, the extraordinary gain (loss) could have been as much as $(2.4) billion, $730 million and $ 453 million (before taxes) as a result of the elimination of ComEd's, PECO's and BGE's regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.4 billion and $568 million for ComEd and BGE, respectively, related to Exelon's regulatory assets associated with its defined benefit postretirement plans. Exelon also has a regulatory liability of $45 million (before taxes) associated with PECO's defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an additional impairment of ComEd's goodwill, which could be significant and at least partially offset the extraordinary gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1, 3 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd's goodwill, respectively.

Exelon and Generation may incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO_2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. The nature and extent of environmental regulation may also impact the ability of Exelon and its subsidiaries to meet the GHG emission reduction targets of Exelon 2020. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS "Global Climate Change" and Note 22 of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of ComEd, PECO, and BGE to the results of PJM's RTEP and NERC compliance requirements. (Exelon, Generation, ComEd, PECO and BGE)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

ComEd, PECO and BGE as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments may require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM's RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. Following a remand from the U.S. Court of Appeals for the Seventh Circuit, FERC reaffirmed its decision related to allocation of new facilities 500 kV and above. That decision is being appealed to the U.S. Court of Appeals for the Seventh Circuit. This FERC order only applies to facilities included in the PJM RTEP prior to February 1, 2013. For facilities subsequently approved, the costs of new facilities that are double circuit 345 kV or greater than or equal to 500 kV will be allocated 50% across the entire PJM footprint and 50% allocated to identified beneficiaries. Costs for all other facilities will be allocated to all identified beneficiaries. This later decision is subject to rehearing by FERC and possible appeal.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could have a material adverse effect on their results of operations, financial positions and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 22 of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants' results of operations.

Generation may be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

***Regulatory risk*.** A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC's focus on seismic risk intensified. As part of the NRC Near-Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. Additionally, the Task Force provided recommendations for future regulatory action by the NRC to be taken in the near and longer term. In response, the NRC issued three immediately effective orders (Tier 1) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. The NRC is currently evaluating the remaining Task Force recommendations and has not taken action with respect to the Tier 2 and Tier 3 recommendations. Actions to comply with the Task Force recommendations will result in increased costs and could significantly impact Generation's results of operations or financial position. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for a more detailed discussion of the Task Force Recommendations.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. In September 2012, the NRC directed NRC Staff to complete a generic environmental impact statement and to revise the temporary storage rule which is now not expected until October 3, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation's ability to decommission fully its nuclear units. In accordance with the NWPA and Generation's contract with the DOE, Generation pays the DOE ongoing fees per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees. Furthermore, under its contract with the DOE, Generation would be required to pay the DOE a one-time SNF storage fee including interest of approximately $1 billion as of December 31, 2013, prior to the first delivery of SNF. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation's nuclear stations or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

As discussed above, in June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

Operational Risks

The Registrants' employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events may adversely affect Exelon's results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation's fleet of nuclear and fossil-fueled power plants and ComEd's, PECO's and BGE's distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Examples of such events include the June 2012 “Derecho” storm, which interrupted electric service delivery to customers in BGE’s service territory, and the October 2012 category 1 hurricane, Hurricane Sandy, which interrupted electric service delivery to customers in PECO’s and BGE’s service territories and resulted in significant costs to PECO and BGE for restoration efforts.

Other events include the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co., and the 5.8 magnitude earthquake and flooding associated with Hurricane Irene and Tropical Storm Lee that the Mid-Atlantic region of the United States experienced in 2011. These events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation’s continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants’ operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets of, or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon’s facilities, which could adversely affect Exelon’s ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may result in a decline in energy consumption, which may adversely affect the Registrants’ results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation’s financial performance may be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation’s results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation’s operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including ComEd, PECO and BGE. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, can have a significant impact on Generation's results of operations. When refueling outages at wholly and co-owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

***Nuclear fuel quality*.** The quality of nuclear fuel utilized by Generation can affect the efficiency and costs of Generation's operations. Certain of Generation's nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

***Operational risk*.** Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, may exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation's results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.6 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's two units that have been retired) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from ComEd customers or from the previous owners of Clinton, TMI Unit No. 1 and Oyster Creek generating stations, if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units may be negatively affected and Exelon's and Generation's results of operations and financial position could be significantly affected. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear plants, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's cash flows and financial position may be significantly adversely affected. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's financial performance may be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires August 31, 2014, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2014. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation's results of operations or financial position. Similar effects may result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

ComEd's, PECO's and BGE's operating costs, and customers' and regulators' opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

Failures of the equipment or facilities, including information systems, used in ComEd's, PECO's and BGE's delivery systems can interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd's, PECO's or BGE's service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd's, PECO's and BGE's financial condition, results of operations, and cash flows could be adversely affected. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, ComEd's, PECO's or BGE's financial results could be adversely affected. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, ComEd's, PECO's or BGE's financial results could also be adversely affected. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd's, PECO's and BGE's maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd's service territory.

ComEd's, PECO's and BGE's respective ability to deliver electricity, their operating costs and their capital expenditures may be negatively affected by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd's, PECO's and BGE's service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd's, PECO's and BGE's ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

Failure to attract and retain an appropriately qualified workforce may negatively impact the Registrants' results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

The Registrants are subject to physical and information security risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical and information security risks as the owner-operators of generation, transmission and distribution facilities. A security breach of the physical assets or information systems of the Registrants, their competitors, RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer data. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence in the Registrants or others in the industry may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. ComEd's, PECO's and BGE's deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. As a requirement of their SGIG grant, the DOE approved PECO's and BGE's cyber security plan related to its smart meter deployment and will review the plan annually through the expiration of the grant. As with most companies in today's environment, Exelon experiences attempts by hackers to infiltrate its corporate network. To date there have been no infiltrations that have resulted in loss of data or any significant effects on business operations. Exelon utilizes a dedicated team of cyber security professionals to ensure the protection of its information and ability to conduct business operations. Despite the measures taken by the Registrants to prevent a security breach, the Registrants cannot accurately assess the probability that a security breach may occur and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

The Registrants may make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions may not achieve the intended financial results. (Exelon, Generation, ComEd, PECO and BGE)

Generation continuously looks to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential power and gas sales, solar and wind generation, and managed load response. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others may impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment. ComEd, PECO and BGE face risks associated with the Smart Grid mandated regulatory initiative. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd's, PECO's or BGE's financial results.

Risks Related to the Merger

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

Risks Related to the Pending Master Agreement with CENG

The integration of CENG's nuclear fleet may not achieve its anticipated results, and Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG that will result in Generation operating the CENG nuclear generation fleet. The Master Agreement was entered into with the expectation that it will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the agreement is subject to a number of uncertainties, including whether CENG can be integrated into Generation in an efficient, effective and timely manner. Integration will take place, and additional agreements will be signed, upon receipt of regulatory approvals for the transfer of CENG's nuclear operating licences to Generation.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Generation's business, processes and systems or inconsistencies in standards, controls, procedures, practices, policies, valuation models, and compensation arrangements. In addition, Generation may have difficulty addressing possible differences in corporate cultures and management philosophies. Any of these circumstances could adversely affect Generation's ability to achieve the anticipated benefits of the agreement as and when expected. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Generation's future business, financial condition, operating results and prospects.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2013:

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,316
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,167[(f)]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,006[(f)]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[(f)(h)]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Keystone	Mid-Atlantic	Shelocta, PA	2	41.98	Coal	Base-load	714[(f)]
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[(e)]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Conemaugh	Mid-Atlantic	New Florence, PA	2	31.28	Coal	Base-load	532[(f)]
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Colver	Mid-Atlantic	Colver Twp., PA	1	25	Waste Coal	Base-load	26[(f)]
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various	2		Solar	Base-load	10
Solar New Jersey 1	Mid-Atlantic	Various	4		Solar	Base-load	10
Solar Maryland	Mid-Atlantic	Various	9		Solar	Base-load	9
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5
Solar Maryland 2	Mid-Atlantic	Pocomoke, MD	2		Solar	Base-load	4
Solar New York	Mid-Atlantic	Various	1		Solar	Base-load	3
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	2
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Safe Harbor	Mid-Atlantic	Conestoga, PA	12	66.7	Hydroelectric	Intermediate	278[(f)]
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Perryman	Mid-Atlantic	Belcamp, MD	5		Oil/Gas	Peaking	353
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Riverside	Mid-Atlantic	Baltimore, MD	4		Oil/Gas	Peaking	228
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	115
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	118
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[(f)]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Keystone	Mid-Atlantic	Shelocta, PA	4	41.98	Oil	Peaking	4[(f)]
Conemaugh	Mid-Atlantic	New Florence, PA	4	31.28	Oil	Peaking	3[(f)]
Total Mid-Atlantic							13,067
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,353
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,319
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,843
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[(f)]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,067
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	81
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	21[(f)]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[(f)]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	8
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[(f)]
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[(f)]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[(f)]
Brewster	Midwest	Jackson Co., MN	6	94-99	Wind	Base-load	6[(f)]
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6[(f)]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[(f)]
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	1
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,055
Whitetail	ERCOT	Laredo, TX	57		Wind	Base-load	91
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	704
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	1		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	1		Gas	Intermediate	488
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							4,003
Holyoke Solar	New England	Various	2		Solar	Base-load	5
Solar Massachusetts	New England	Various	5		Solar	Base-load	3
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	2		Gas	Intermediate	1,418
Fore River	New England	North Weymouth, MA	1		Gas	Intermediate	726
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36[(f)]
Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	117
Framingham	New England	Framingham, MA	3		Oil	Peaking	33
New Boston	New England	South Boston, MA	1		Oil	Peaking	16
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,941
Nine Mile Point	New York	Scriba, NY	2	50.01[(h)]	Uranium	Base-load	833[(f)(h)]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[(f)(h)]
Total New York							1,121
AVSR	Other	Lancaster, CA	1		Solar	Base-load	198[(g)]
Shooting Star	Other	Greensburg, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	35[(f)]
Sacramento PV Energy	Other	Sacremento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[(f)]
Echo 2	Other	Echo, OR	10		Wind	Base-load	20

Station (a)	Region	Location	No. of Units	Percent Owned (b)	Primary Fuel Type	Primary Dispatch Type (c)	Net Generation Capacity (MW) (d)
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10(f)
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10(f)
Threemile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar Arizona	Other	Various	20		Solar	Base-load	29
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
California PV Energy	Other	Ontario, CA	2		Solar	Base-load	3
Solar California	Other	Various	4		Solar	Base-load	2
Hillabee	Other	Alexander City, AL	1		Gas	Intermediate	670
Malacha	Other	Muck Valley, CA	1	50	Hydroelectric	Intermediate	15(f)(i)
West Valley	Other	Salt Lake City, UT	5		Gas	Peaking	185
Grand Prairie	Other	Alberta, Canada	1		Gas	Peaking	75
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	8(f)
Total Other							1,950
Total							35,137

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Expected capacity upon project completion is 230MW. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(h) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon's ownership is 50.01% of 82% of Nine Mile Point Unit 2. Generation also has a unit-contingent PPA with CENG under which it purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties under the pre-existing PPAs through 2014.
(i) In February 2014, Generation sold its remaining stake in Malacha.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. Business—Generation. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,642
138,000	2,292

ComEd's electric distribution system includes 35,491 circuit miles of overhead lines and 30,626 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188[a]
230,000	548
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 12,989 circuit miles of overhead lines and 8,915 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	31
Distribution	6,764
Service piping	6,068
Total	12,863

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	322
138,000	54
115,000	697

BGE's electric distribution system includes 9,391 circuit miles of overhead lines and 15,933 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	163
Distribution	7,054
Service piping	6,146
Total	13,363

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,055 mmcf and a send-out capacity of 332 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 6 mmcf and a send-out capacity of 6 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 546 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2014, there were 857,419,806 shares of common stock outstanding and approximately 129,928 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

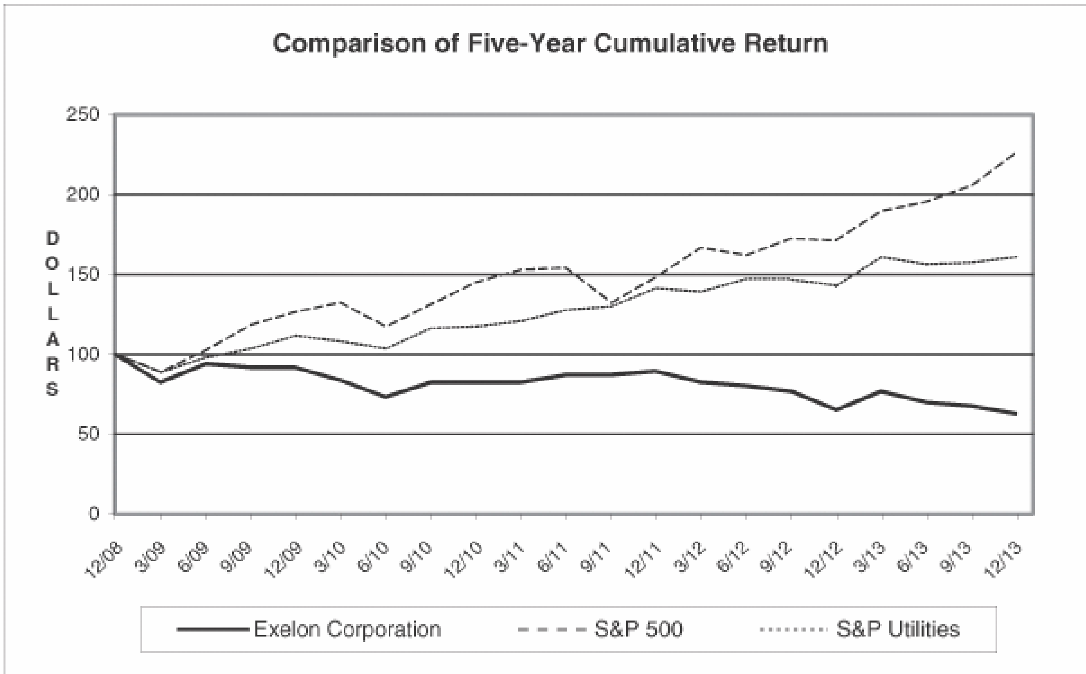
	2013				2012			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 30.59	$ 32.42	$ 37.80	$ 34.56	$ 37.50	$ 39.82	$ 39.37	$ 43.70
Low price	26.64	29.42	29.84	29.10	28.40	34.54	36.27	38.31
Close	27.39	29.64	30.88	34.48	29.74	35.58	37.62	39.21
Dividends	0.310	0.310	0.310	0.525	0.525	0.525	0.525	0.525

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2009 through 2013.

This performance chart assumes:

- $100 invested on December 31, 2008 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.



	Value of Investment at December 31,					
	2008	2009	2010	2011	2012	2013
Exelon Corporation	$100.00	$91.60	$82.04	$89.76	$65.21	$62.94
S&P 500	$100.00	$126.45	$145.49	$148.55	$172.31	$228.10
S&P Utilities	$100.00	$111.91	$118.02	$141.54	$143.37	$162.31

Generation

As of January 31, 2014, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2014, there were 127,016,904 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2014, in addition to Exelon, there were 294 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2014, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2014, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

Under applicable Federal law, Generation, ComEd, PECO and BGE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO or BGE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility “to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account.” What constitutes “funds properly included in capital account” is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon’s actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, “[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves,” or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE’s equity ratio would be below 48% as calculated pursuant to the MDPSC’s ratemaking precedents or (b) BGE’s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation's undistributed earnings of $3,613 million, ComEd's retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million, partially offset by $1,639 million of unappropriated retained deficits, PECO's retained earnings of $649 million, and BGE's retained earnings of $1,005 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2013 and 2012:

	2013				2012			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525

The following table sets forth Generation's quarterly distributions and ComEd's and PECO's quarterly common dividend payments:

	2013				2012			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 75	$ 76	$ 263	$ 211	$ 242	$ 493	$ 291	$ 600
ComEd	55	55	55	55	10	10	10	75
PECO	83	83	83	83	85	86	85	87

First Quarter 2014 Dividend. On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions, except per share data)	2013	2012 [(a)]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$24,888	$23,489	$19,063	$18,644	$17,318
Operating income	3,656	2,380	4,479	4,726	4,750
Income from continuing operations	1,729	1,171	2,499	2,563	2,706
Income from discontinued operations	—	—	—	—	1
Net income	1,729	1,171	2,499	2,563	2,707
Earnings per average common share (diluted):					
Income from continuing operations	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Net income	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Dividends per common share	$ 1.46	$ 2.10	$ 2.10	$ 2.10	$ 2.10
Average shares of common stock outstanding—diluted	860	819	665	663	662

(a) The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

(In millions)	December 31, 2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$ 10,137	$ 10,140	$ 5,713	$ 6,398	$ 5,441
Property, plant and equipment, net	47,330	45,186	32,570	29,941	27,341
Noncurrent regulatory assets	5,910	6,497	4,518	4,140	4,872
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	13,922	14,113	9,569	9,136	8,901
Total assets	$79,924	$78,561	$54,995	$52,240	$49,180
Current liabilities	$ 7,728	$ 7,791	$ 5,134	$ 4,240	$ 4,238
Long-term debt, including long-term debt to financing trusts	18,271	18,346	12,189	12,004	11,385
Noncurrent regulatory liabilities	4,388	3,981	3,627	3,555	3,492
Other deferred credits and other liabilities	26,597	26,626	19,570	18,791	17,338
Preferred securities of subsidiary	—	87	87	87	87
Non-controlling interest	15	106	3	3	—
BGE preference stock not subject to mandatory redemption	193	193	—	—	—
Shareholders’ equity	22,732	21,431	14,385	13,560	12,640
Total liabilities and shareholders’ equity	$79,924	$78,561	$54,995	$52,240	$49,180

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation’s Consolidated Financial Statements and ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	For the Years Ended December 31, 2013	2012 [(a)]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$15,630	$14,437	$10,447	$10,025	$9,703
Operating income	1,664	1,120	2,875	3,046	3,295
Net income	1,060	558	1,771	1,972	2,122

(a) The 2012 financial results only include the operations of Constellation from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

(In millions)	December 31, 2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$ 6,439	$ 6,211	$ 3,217	$ 3,087	$ 3,360
Property, plant and equipment, net	20,111	19,531	13,475	11,662	9,809
Other deferred debits and other assets	14,682	14,939	10,741	9,785	9,237
Total assets	$41,232	$40,681	$27,433	$24,534	$22,406
Current liabilities	$ 3,867	$ 4,097	$ 2,144	$ 1,843	$ 2,262
Long-term debt	7,168	7,455	3,674	3,676	2,967
Other deferred credits and other liabilities	17,455	16,464	12,907	11,838	10,385
Non-controlling interest	17	108	5	5	2
Member’s equity	12,725	12,557	8,703	7,172	6,790
Total liabilities and member’s equity	$41,232	$40,681	$27,433	$24,534	$22,406

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2013	2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$4,464	$5,443	$6,056	$6,204	$5,774
Operating income	954	886	982	1,056	843
Net income	249	379	416	337	374

	December 31,				
(In millions)	2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$ 1,540	$ 1,775	$ 2,188	$ 2,151	$ 1,579
Property, plant and equipment, net	14,666	13,826	13,121	12,578	12,125
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	933	666	699	947	1,096
Other deferred debits and other assets	4,354	4,013	4,005	3,351	3,272
Total assets	$ 24,118	$22,905	$22,638	$21,652	$20,697
Current liabilities	$ 2,048	$ 1,655	$ 2,071	$ 2,134	$ 1,597
Long-term debt, including long-term debt to financing trusts	5,264	5,521	5,421	4,860	4,704
Noncurrent regulatory liabilities	3,512	3,229	3,042	3,137	3,145
Other deferred credits and other liabilities	5,766	5,177	5,067	4,611	4,369
Shareholders' equity	7,528	7,323	7,037	6,910	6,882
Total liabilities and shareholders' equity	$ 24,118	$22,905	$22,638	$21,652	$20,697

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2013	2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$3,100	$3,186	$3,720	$5,519	$5,311
Operating income	666	623	655	661	697
Net income	395	381	389	324	353
Net income on common stock	388	377	385	320	349

(In millions)	2013	2012	December 31, 2011	2010	2009
Balance Sheet data:					
Current assets	$ 906	$ 1,094	$ 1,243	$ 1,670	$ 1,006
Property, plant and equipment, net	6,384	6,078	5,874	5,620	5,297
Noncurrent regulatory assets	1,448	1,378	1,216	968	1,834
Other deferred debits and other assets	879	803	823	727	882
Total assets	$9,617	$9,353	$9,156	$8,985	$9,019
Current liabilities	$ 891	$ 1,158	$ 1,145	$ 1,163	$ 939
Long-term debt, including long-term debt to financing trusts	2,131	1,831	1,781	2,156	2,405
Noncurrent regulatory liabilities	629	538	585	418	317
Other deferred credits and other liabilities	2,901	2,757	2,620	2,278	2,706
Preferred securities	—	87	87	87	87
Shareholders' equity	3,065	2,982	2,938	2,883	2,565
Total liabilities and shareholders' equity	$9,617	$9,353	$9,156	$8,985	$9,019

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	2013	2012	For the Years Ended December 31, 2011	2010	2009
Statement of Operations data:					
Operating revenues	$3,065	$2,735	$3,068	$3,541	$3,646
Operating income	449	132	314	350	268
Net income	210	4	136	147	91
Net income (loss) attributable to common shareholder	197	(9)	123	134	78

(In millions)	2013	2012 [(a)]	December 31, 2011 [(a)]	2010 [(a)]	2009 [(a)]
Balance Sheet data:					
Current assets	$ 1,011	$ 980	$ 969	$ 1,012	$ 1,205
Property, plant and equipment, net	5,864	5,498	5,132	4,754	4,470
Noncurrent regulatory assets	524	522	551	566	602
Other deferred debits and other assets	462	506	551	545	386
Total assets	$7,861	$7,506	$7,203	$6,877	$6,663
Current liabilities	$ 827	$ 980	$ 734	$ 728	$ 753
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,199	1,969	2,186	2,060	2,141
Noncurrent regulatory liabilities	204	214	201	192	188
Other deferred credits and other liabilities	2,076	1,985	1,781	1,634	1,434
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders' equity	2,365	2,168	2,111	2,073	1,939
Non-controlling interest	—	—	—	—	18
Total liabilities and shareholders' equity	$7,861	$7,506	$7,203	$6,877	$6,663

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions in Generation), ComEd, PECO and BGE. See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for year ended December 31, 2013 compared to the same period in 2012. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

Results in 2013 were unfavorably impacted at Generation by continuing declines in realized power and gas prices, in part driven by the abundance of natural gas supply, continued sluggish demand and subsidized renewable generation; only partially offset by improved returns at the utilities, and the realization of additional post-merger synergies and operational excellence across all businesses. Generation's financial results continue to be challenged by low natural gas prices, and by the impacts of excess generation from subsidized renewable energy, flat load growth and distorted market designs, especially in its Midwest markets.

	The Years Ended December 31,							Favorable (Unfavorable) Variance
	2013						2012	
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 15,630	$4,464	$3,100	$3,065	$(1,371)	$24,888	$23,489	$ 1,399
Purchased power and fuel	8,197	1,174	1,300	1,421	(1,368)	10,724	10,157	(567)
Revenue net of purchased power and fuel [(a)]	7,433	3,290	1,800	1,644	(3)	14,164	13,332	832
Other operating expenses								
Operating and maintenance	4,534	1,368	748	634	(14)	7,270	7,961	691
Depreciation and amortization	856	669	228	348	52	2,153	1,881	(272)
Taxes other than income	389	299	158	213	36	1,095	1,019	(76)
Total other operating expenses	5,779	2,336	1,134	1,195	74	10,518	10,861	343
Equity in earnings/(losses) of unconsolidated affiliates	10	—	—	—	—	10	(91)	101
Operating income	1,664	954	666	449	(77)	3,656	2,380	1,276
Other income and (deductions)								
Interest expense, net	(357)	(579)	(115)	(122)	(183)	(1,356)	(928)	(428)
Other, net	368	26	6	17	56	473	346	127
Total other income and (deductions)	11	(553)	(109)	(105)	(127)	(883)	(582)	(301)
Income (loss) before income taxes	1,675	401	557	344	(204)	2,773	1,798	975
Income taxes	615	152	162	134	(19)	1,044	627	(417)
Net income (loss)	1,060	249	395	210	(185)	1,729	1,171	558
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(10)	—	7	13	—	10	11	1
Net income (loss) on common stock	$ 1,070	$ 249	$ 388	$ 197	$ (185)	$ 1,719	$ 1,160	$ 559

(a) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon's net income on common stock was $1,719 million for the year ended December 31, 2013 as compared to $1,160 million for the year ended December 31, 2012, and diluted earnings per average common share were $ 2.00 for the year ended December 31, 2013 as compared to $1.42 for the year ended December 31, 2012.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $832 million as compared to 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense reflects the inclusion of Constellation and BGE's results for the full period in 2013 and was primarily due to the following favorable factors:

- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the merger date of $610 million;

- Increase in BGE's revenue net of purchased power and fuel expense of $278 million, primarily as a result of the inclusion of BGE's results for the full period in 2013, accrual of the residential customer rate credit that was a condition of the MDPSC's approval of Exelon's merger with Constellation in 2012, and the impact of the MDPSC approved electric and natural gas distribution rate increases that became effective February 23, 2013;
- Increase in Generation's revenue net of purchased power and fuel of $159 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation; and
- Increase in ComEd's revenue net of purchased power expense of $154 million primarily due to increased distribution revenue due to recovery of increased costs and capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease in Generation's electric revenue net of purchased power and fuel expense of $565 million primarily due to lower realized energy prices, lower load volume and increased nuclear fuel expense, partially offset by higher capacity revenue, increased nuclear volumes, and lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger;
- Reduced revenue net of purchased power and fuel at Generation of $136 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012; and
- Decrease in PECO's revenue net of purchased power and fuel expense of $11 million primarily due to the decrease in effective rates due to increased usage per customer across all customer classes, decreased cost recovery for energy efficiency and demand response programs, decreased gross receipts tax revenue, and the customer refund in 2013 of the tax cash benefit related to gas property distribution repairs.

Operating and maintenance expense decreased by $691 million as compared to 2012 primarily due to the following favorable factors:

- Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $442 million;
- Costs incurred in March 2012 of $216 million and $195 million as part of the Maryland order approving the merger and a settlement with the FERC, respectively;
- Decrease in Constellation merger and integration costs of $201 million in 2013; and
- Decrease in uncollectible accounts expense of $58 million at ComEd resulting from the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers.

The year-over-year decrease in operating and maintenance expense was partially offset by the following unfavorable factors:

- Increase in labor, other benefits, contracting and materials costs of $298 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and
- Long-lived asset impairments and related charges of $174 million in 2013, primarily related to Generation's cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

Depreciation and amortization expense increased by $272 million primarily due to the addition of BGE and Constellation for the full period in 2013, BGE's and Constellation's plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation, and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

The favorable increase in Equity in earnings/loss of unconsolidated affiliates of $101 million was primarily due to higher net income from Generation's equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $428 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in project financing at Generation in 2013.

Exelon's effective income tax rates for the years ended December 31, 2013 and 2012 were 37.6% and 34.9%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2013 and 2012, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2013 were $2,149 million, or $2.50 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,330 million, or $2.85 per diluted share, for the same period in 2012. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2013 as compared to 2012:

	December 31,			
	2013		2012	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$1,719	$ 2.00	$ 1,160	$ 1.42
Mark-to-Market Impact of Economic Hedging Activities (a)	(310)	(0.35)	(310)	(0.38)
Unrealized Net Gains Related to NDT Fund Investments (b)	(78)	(0.09)	(56)	(0.07)
Plant Retirements and Divestitures (c)	(13)	(0.02)	236	0.29
Asset Retirement Obligation (d)	7	0.01	1	—
Merger and Integration Costs (e)	87	0.08	257	0.31
Other Acquisition Costs (f)	—	—	3	—
Reassessment of State Deferred Income Taxes (g)	4	—	(117)	(0.14)
Amortization of Commodity Contract Intangibles (h)	347	0.41	758	0.93
Amortization of the Fair Value of Certain Debt (i)	(7)	(0.01)	(9)	(0.01)
Remeasurement of Like-Kind Exchange Tax Position (j)	267	0.31	—	—
Long-Lived Asset Impairment (k)	110	0.14	—	—
Maryland Commitments (l)	—	—	227	0.28
FERC Settlement (m)	—	—	172	0.21
Midwest Generation Bankruptcy Charges (n)	16	0.02	8	0.01
Adjusted (non-GAAP) Operating Earnings	$2,149	$ 2.50	$2,330	$ 2.85

(a) Reflects the impact of (gains) losses for the years ended December 31, 2013 and 2012, respectively, on Generation's economic hedging activities (net of taxes of $201 million and $200 million, respectively). In order to better align the impacts of economic hedging with the underlying business activity (e.g. the sale of power and/or the use of fuel), these unrealized (gains) losses are excluded from operating earnings until the transactions are realized. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized gains for the years ended December 31, 2013 and 2012, respectively, on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(144) million and $(132) million, respectively). See Note 15—Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations in the years ended December 31, 2013 and 2012 (net of taxes of $4 million and $106 million, respectively). See "Results of Operations—Generation" for additional detail related to the generating unit retirements.

(d) Primarily reflects the impact of an increase in Generation's asset retirement obligation for asbestos at retired fossil plants for the year ended December 31, 2013 (net of taxes of $(5) million). Primarily reflects the impact of an increase in Generation's decommissioning obligation for spent nuclear fuel at retired nuclear units for the year ended December 31, 2012 (net of taxes of $(1) million).

(e) Reflects certain costs incurred in the years ended December 31, 2013 and 2012 (net of taxes of $33 million and $161 million, respectively) associated with the merger, including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives, certain pre-acquisition contingencies, and CENG transaction costs, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4—Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the year ended 2012 associated with various acquisitions (net of taxes of $2 million).

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment in 2013 and as a result of the merger in 2012. See Note 14—Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects the non-cash impact for the years ended December 31, 2013 and 2012 (net of taxes of $219 million and $491 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4—Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects the non-cash amortization of certain debt for the years ended December 31, 2013 and 2012 (net of taxes of $5 million and $6 million, respectively) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.
(j) Reflects a non-cash charge to earnings for the year ended December 31, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 14 of the Combined Notes to the Consolidated Financial statements for additional information.
(k) Reflects 2013 impairment and related charges to earnings for the year ended December 31, 2013 (net of taxes of $69 million) primarily related to Generation's cancellation of nuclear uprate projects and the impairment of certain wind generating assets.
(l) Reflects costs incurred for the year ended December 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(m) Reflects costs incurred for the year ended December 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.
(n) Reflects costs incurred to establish estimated liabilities for the years ended December 31, 2013 and December 31, 2012 (net of taxes of $10 million and $5 million, respectively) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, including meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the year ended December 31, 2013, expense has been recognized for costs incurred to achieve the merger, prior to consideration of regulatory accounting treatment, as follows:

	Pre-tax Expense Twelve Months Ended December 31, 2013				
Merger and Integration Costs:	**Generation [a]**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Employee-Related [b]	48	4	3	1	58
Other [c]	58	12	6	5	84
Total	$ 106	$ 16	$ 9	$ 6	$ 142

	Pre-tax Expense Twelve Months Ended December 31, 2012				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Maryland Commitments	35	—	—	139	328
Employee-Related [b]	138	24	11	24	207
Other [c]	167	17	6	7	211
Transaction [d]	$ —	$ —	$—	$ —	$ 58
Total	$ 340	$ 41	$ 17	$ 170	$ 804

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger March 12, 2012 through the year ended December 31, 2013.
(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million and $21 million for the years ended December 31, 2013 and December 31, 2012, respectively. BGE established regulatory assets of $0 million and $22 million for the years ended December 31, 2013 and December 31, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $9 million and $15 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs. BGE established a regulatory asset of $12 million and $0 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs.
(d) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of December 31, 2013, Exelon expects to incur total additional Constellation merger-related expenses in 2014 and 2015 of approximately $34 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once required approvals are received and financing condition is satisfied, construction of the building will commence. The building is expected to be ready for occupancy in two years following commencement of construction. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon's Strategy and Outlook for 2014 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon's clean generation fleet with Constellation's leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation's competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help mitigate the current challenging conditions in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $15 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand due to factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these market pricing issues.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2014 and 2015 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low-carbon generation such as wind and solar energy in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development, which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term capacity Pilot Program (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between generators receive in the capacity market and the price guaranteed under the 15 year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently sought to extend that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court. On October 25, 2013, the U.S. District Court in New Jersey issued a judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey SOCA contract is unenforceable. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC's Order directing BGE and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements. In addition, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC's statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. The non-prevailing parties have sought appeals in federal appellate court in both the New Jersey and

Maryland federal litigation. Finally, on October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation.

As required under their contracts, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auctions held in May 2012 and 2013. In addition, CPV has announced its intention to move forward with construction of its New Jersey plant, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. While the U.S. District Court decisions in Maryland and New Jersey are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR), could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

PJM's capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM's rules related to the capacity auction. Accordingly, Exelon is working with other market stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sponsored subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Exelon remains active in advocating for competitive markets, opposing policies that ask either taxpayers or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across each of the Exelon utility companies. ComEd is projecting load volumes to decrease by 0.2% in 2014 compared to 2013, while PECO and BGE are projecting an increase of 0.3% and 0.6%, respectively, in 2014 compared to 2013.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon's previous dividend of $2.10 per share on an annualized basis. The second, third and fourth quarter dividends were based on Exelon's new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). All future quarterly dividends require approval by Exelon's board of directors.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon's and Generation's results of operations, financial position, and cash flows through among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2014 and 2015. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon's existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon's expertise in those areas.

Transmission Development Project. Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop an extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost and scope of the project are dependent on a number of factors, including RTO requirements, interregional transmission planning process requirements, state siting requirements, routing of the line, and equipment and commodity costs. Exelon and AEP are currently pursuing the project and other segments that are electrically equivalent in nature for inclusion in interregional planning process between PJM and MISO; if approved through that process, the project would then need to be approved through the respective planning processes of PJM and MISO.

On July 18, 2011, RITELine Illinois and RITELine Indiana filed at FERC for incentive rates and a formula rate for the RITE Line project. On October 14, 2011, FERC issued an order on the incentive and formula rate filing. The order grants a base rate of return on common equity of 9.9%, plus a 50 basis point adder for the project being in a RTO and a 100 basis point adder for the risks and challenges of the project, resulting in a total rate of return on common equity of 11.4%. The order grants a hypothetical capital structure of 45% debt and 55% equity until any part of the project enters commercial operations. The order also grants 100% recovery for construction work in progress, 100% recovery for abandonment, if the line is abandoned through no fault of the RITELine developers, and the ability to treat pre-construction costs as a regulatory asset. All incentives, including the abandonment incentive, are contingent on inclusion of the project in the PJM RTEP. The RITELine companies filed for rehearing on several rate of return on common equity issues and argued that the right to collect abandoned costs should not be subject to the project being included in the RTEP. The RITELine companies also made a compliance filing as called for in the October 14, 2011 Order. FERC accepted this filing on March 16, 2012.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million. In addition, Generation constructed and placed into service 400 MWs of additional wind generation in 2012 at a cost of $710 million and another 50 MW will be added to Generation's wind portfolio in 2014 with the expansion of its Beebe project in Michigan, the output of which will be fully contracted under a 20-year PPA.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2013, approximately 30%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants' credit facilities as of December 31, 2013. See Note 13—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

February 5, 2014 Winter Ice Storm. On February 5, 2014, a winter storm which brought a mix of snow, ice and freezing rain to the region interrupted electric service delivery to nearly 715,000 customers in PECO's service territory. Restoration efforts are continuing and will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will result in $60 million to $80 million of incremental operating and maintenance expense and $30 million to $40 million of incremental capital expenditures for the first quarter of 2014.

Tax Matters

See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in fall 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision. Oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court will not occur until 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President

Obama's June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President's memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources. Pursuant to the President's Climate Action Plan, the U.S. EPA re-proposed regulations for the GHG emissions from new fossil fueled power plants on September 20, 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results would benefit.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013; on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until November 20, 2013 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have stated that the deadline will be extended again for a brief period, but have not yet agreed on a date. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation's facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost-benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation's plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has entered into a Consent Decree which requires that a final rule be issued by December 19, 2014.

See Note 22 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The NRC staff and the Task Force concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools.

In 2012, the NRC authorized its staff to issue three immediately effective orders (Tier 1 orders) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In addition, in 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors (BWR) with Mark I and Mark II containment structures. In summary, through the initial and/or subsequent orders and the NRC approved implementation guidance, the Tier 1 orders currently: (1) require licensees to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the core and spent fuel pool and to maintain containment integrity until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) provide requirements for vents for BWR's with Mark I and Mark II containments to remain functional during severe accident conditions including the ability to vent the containment following core damage; and (3) require licensees to install instrumentation to provide a reliable indication of water level in the spent fuel pool. Finally, the NRC has directed the NRC staff to produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options for BWR's with Mark I and Mark II containments. The NRC staff must then develop a final rule by March 2017.

Additionally, in 2012, the NRC had issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. The nuclear industry proposed, and the NRC approved, an augmented approach to the seismic hazard analysis to accommodate industry wide availability of qualified technical resources needed to perform the required analysis. The NRC approved this augmented approach.

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2014 through 2018 is expected to be between approximately $350 million and $375 million of capital and $50 million of operating expense, as previously anticipated in Generation's planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon's previous expectations due to the following factors: (a) the majority of Generation's physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation's credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

Formula Rate Tariff

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd's pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd's weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor's veto of that Bill. On June 5, 2013, the ICC approved ComEd's updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd's 2014 revenue by approximately $8 million. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals. See 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Annual Reconciliation

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated on May 30, 2013 to reflect the impacts of Senate Bill 9. The ICC's final order, issued on December 19, 2013, increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals. ComEd cannot predict the results of any such appeals. See 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's " *Mobile-Sierra*" standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their Mobile-Sierra and related arguments. The compliance filing was made on July 22, 2013. On January 16, 2014, FERC issued an order stating that PJM's filing while subject to further orders, is effective as of January 1, 2014.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE's base return on equity to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE cannot predict the outcome of this proceeding or how much of the requested plan and related surcharge the MDPSC will approve. The MDPSC held evidentiary hearings on BGE’s proposed plan and surcharge on November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE’s plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers’ bills. The new surcharges are expected to take effect in the second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the accounting policies described below require significant judgment in their application, or estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation’s ARO associated with decommissioning its nuclear units was $4.9 billion at December 31, 2013. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios. The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation’s nuclear units at least every five years.

Cost Escalation Factors. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs.

Probabilistic Cash Flow Models. Generation’s probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are assigned to alternative decommissioning approaches which assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations) decommissioning. Probabilities assigned to the timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals. Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal, which Generation assumed would begin in 2025 in 2013 and 2012. The SNF acceptance date was based on management's estimates of the amount of time required for the DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 22 of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. The current NRC license for Oyster Creek expires in 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. As a result of this decision the expected economic life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. Generation has successfully secured 20-year operating license renewal extensions for ten of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation's applications for an operating license extension have been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining nine operating nuclear units. Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for ten units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $210 million per unit as of December 31, 2013. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $4.9 billion to approximately $5.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2013 at fair value of approximately $8.1 billion and have an estimated targeted annual pre-tax return of 5.9 % to 6.7 %.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had

Generation used the 2012 CARFRs rather than the 2013 CARFRs in performing its third quarter 2013 ARO update, Generation would have reduced the ARO by approximately $10 million as compared to the actual decrease to the ARO of $140 million; and ii) if the CARFR used in performing the third quarter 2013 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have decreased by $300 million and increased $40 million, respectively, as compared to the actual decrease of $140 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well. As an example, Exelon had a historical increase of approximately $670 million in the value of the ARO which was driven by Generation modifying the assumed timing of the DOE acceptance of SNF for disposal from 2020 to 2025. The modification of the assumed DOE acceptance date affected the calculation of the ARO in isolation as follows; i) the change in the timing of DOE acceptance of SNF increased the total number of years in which decommissioning activities are estimated to occur, by five years on average, thereby increasing the total expected nominal cash flows required to decommission the units; ii) the nominal cash flows were subjected to additional escalation as a result of the extension of the decommissioning period increasing the total estimated costs required to decommission the units; and iii) the escalated cash flows were discounted at the then current CARFRs which had dramatically decreased during that time period.

The following table illustrates the effects of changing certain ARO assumptions, discussed above, while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption		Increase (Decrease) to ARO at December 31, 2013
Cost escalation studies		
Uniform increase in escalation rates of 25 basis points	$	560
Probabilistic cash flow models		
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$	190
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	290
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$	430
Extend the estimated date for DOE acceptance of SNF to 2030	$	50
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$	(230)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$	600

For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 15 of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2013, Exelon’s and ComEd’s carrying amount of goodwill was approximately $2.6 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or operating component and is the level at which goodwill is tested for impairment. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd's earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business, and the fair value of debt, could potentially result in a future impairment of ComEd's goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test. See Note 1—Significant Accounting Policies, Note 10—Intangible Assets and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4—Mergers and Acquisitions and Note 10—Intangible Assets for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Conditions that could have an adverse impact on the cash flows and fair value of the long-lived assets are deteriorating business climate, including current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of other groups of assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units and associated intangible contract assets recorded on the balance sheet. The cash flows from the generation units are generally evaluated at a regional portfolio level with cash flows generated from Generation's customer supply and risk management activities, including cash flows from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. In certain cases generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables).

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances frequently do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires adjustment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce either the long-lived asset or asset group, including any intangible contract assets and liabilities, and current period earnings by the amount of the impairment.

Generation evaluates unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved gas property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience indicates a decline in carrying value below fair value.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments using a discounted cash flow analysis, which takes into consideration the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates.

Generation also evaluates its equity method investments to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature. Additionally, if one of Generation's equity method investments recognize an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates. Generation would also evaluate the investment for a decline in value at that time that is not temporary in nature.

See Note 8 of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a significant impact on the amount of depreciation expense recorded in the income statement. See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates annually the estimated service lives of its generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations. Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd completed a depreciation study in 2014 and filed the updated depreciation rates with both FERC and the ICC in January 2014. This is expected to result in the implementation of new depreciation rates effective first quarter 2014.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2010 for electric transmission assets and January 1, 2011 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE's depreciation studies. In December 2006, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized July 1, 2010.

Defined Benefit Pension and Other Postretirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term expected rate of return on plan assets assumption used in calculating pension costs was 7.50%, 7.50%, and 8.00% for 2013, 2012 and 2011, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 6.45%, 6.68%, and 7.08% in 2013, 2012 and 2011, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2013 were 6.73% and 11.41%, respectively, compared to an expected long-term return assumption of 7.50% and 6.45%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations were 4.80% and 4.90%, respectively, at December 31, 2013. The discount rates at December 31, 2013 represent weighted-average rates for both pension and other postretirement benefit plans. At December 31, 2013 and 2012, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 4.80% and 4.90% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers.

One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon changed the manner in which it will receive prescription drug subsidies beginning in 2013.

The Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Effective in 2002, Constellation amended its other postretirement benefit plans for all subsidiaries other than Nine Mile Point by capping retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 at 2002 levels. Therefore, the excise tax is not expected to have a material impact on the legacy Constellation other postretirement benefit plans. However, certain key assumptions are required to estimate the impact of the excise tax on the other postretirement obligation for legacy Exelon plans, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Health Care Cost Trend Rate. Assumed health care cost trend rates have a significant effect on the costs reported for Exelon's other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed an initial health care cost trend rate of 6.50% for 2013, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2013 cost:				
Discount rate [a]	0.5%	$ (63)	$ (34)	$ (97)
	(0.5%)	68	48	116
EROA	0.5%	(68)	(10)	(78)
	(0.5%)	68	10	78
Health care cost trend rate	1.00%	N/A	90	90
	(1.00%)	N/A	(62)	(62)
Change in benefit obligation at December 31, 2013:				
Discount rate [a]	0.5%	(904)	(297)	(1,201)
	(0.5%)	965	318	1,283
Health care cost trend rate	1.00%	N/A	858	858
	(1.00%)	N/A	(607)	(607)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.8 years, 11.9 years, and 12.1 years for the years ended December 31, 2013, 2012 and 2011, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.7 years, 8.9 years and 6.6 years for the years ended December 31, 2013, 2012 and 2011, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.8 years, 10.1 years and 8.7 years for the years ended December 31, 2013, 2012 and 2011, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in ComEd's, PECO's and BGE's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, to which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd's distribution formula rate tariff, pursuant to EIMA, and FERC-approved transmission formula rate tariffs for ComEd and BGE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd's, PECO's and BGE's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

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

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd had a financial swap contract with Generation that expired May 31, 2013 and currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for ComEd, PECO and BGE, changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements and all of BGE's full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Notes 11 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2013 and 2012 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants' results of operations, financial position and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Sources of Revenue and Selection of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail); the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting. Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas, and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting. The Registrants record revenues using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to risk management activities and economic hedges of other accrual activities. Mark-to-market revenues include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Use of Estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliations can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Unbilled Revenues. The determination of Generation's, ComEd's, PECO's and BGE's retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information.

***Regulated Transmission & Distribution Revenues*.** ComEd's EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd's and BGE's FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2013, 2012 and 2011 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2013	2012 (a)	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Exelon	$1,719	$1,160	$ 559	$2,495	$ (1,335)
Generation	1,070	562	508	1,771	(1,209)
ComEd	249	379	(130)	416	(37)
PECO	388	377	11	385	(8)
BGE	197	(9)	206	123	(132)

(a) For BGE, reflects BGE's operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

Results of Operations—Generation

	2013	2012 (b)	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$15,630	$14,437	$ 1,193	$10,447	$ 3,990
Purchased power and fuel expense	8,197	7,061	(1,136)	3,589	(3,472)
Revenue net of purchased power and fuel expense (a)	7,433	7,376	57	6,858	518
Other operating expenses					
Operating and maintenance	4,534	5,028	494	3,148	(1,880)
Depreciation and amortization	856	768	(88)	570	(198)
Taxes other than income	389	369	(20)	264	(105)
Total other operating expenses	5,779	6,165	386	3,982	(2,183)
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	101	(1)	(90)
Operating income	1,664	1,120	544	2,875	(1,755)
Other income and (deductions)					
Interest expense	(357)	(301)	(56)	(170)	(131)
Other, net	368	239	129	122	117
Total other income and (deductions)	11	(62)	73	(48)	(14)
Income before income taxes	1,675	1,058	617	2,827	(1,769)
Income taxes	615	500	(115)	1,056	556
Net income	1,060	558	502	1,771	(1,213)
Net loss attributable to non-controlling interest	(10)	(4)	(6)	—	4
Net income attributable to membership interest	$ 1,070	$ 562	$ 508	$ 1,771	$ (1,209)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) Includes the operations of Constellation from the date of the merger, March 12, 2012, through December 31, 2012.

Net Income Attributable to Membership Interest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation's net income attributable to membership interest increased compared to the same period in 2012 primarily due to higher revenues, net of purchased power and fuel expense, lower operating and maintenance expense and higher earnings from Generation's interest in CENG; partially offset by impairment of certain generating assets, higher depreciation expense, higher property taxes, and higher interest expense. The increase in revenues, net or purchased power and fuel expense was primarily due to increased capacity prices and higher nuclear volume partially offset by lower realized energy prices, higher nuclear fuel costs, and lower mark-to-market gains in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with FERC in 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation's net income attributable to membership interest decreased compared to the same period in 2012 primarily due to higher operating expenses, the loss on the sale of Brandon Shores, Wagner and C.P. Crane (collectively Maryland generating stations) and the amortization of acquired energy contracts recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. The increase in operating expenses was due to the addition of Constellation's financial results from March 12, 2012, costs related to a 2012 settlement with FERC and transaction and employee-related severance costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the merger. See Note 4 for additional information regarding the loss on the sale of three Maryland generating stations.

Revenue Net of Purchased Power and Fuel Expense

Generation's six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO/RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of

Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities and allocates resources using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the year ended December 31, 2013 compared to 2012 and 2012 compared to 2011, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2013 vs. 2012			2012 vs. 2011	
	2013	2012 [(a)]	Variance	% Change	2011	Variance	% Change
Mid-Atlantic [(b)(f)]	$3,270	$3,433	$ (163)	(4.7)%	$3,350	$ 83	2.5%
Midwest [(c)]	2,586	2,998	(412)	(13.7)%	3,547	(549)	(15.5)%
New England	185	196	(11)	(5.6)%	9	187	n.m.
New York [(f)]	(4)	76	(80)	(105.3)%	—	76	n.m.
ERCOT	436	405	31	7.7%	84	321	n.m.
Other Regions [(d)]	201	131	70	53.4%	(14)	145	n.m.
Total electric revenue net of purchased power and fuel expense	$6,674	$7,239	$ (565)	(7.8)%	$6,976	$ 263	3.8%
Proprietary Trading	(8)	(14)	6	42.9%	24	(38)	n.m.
Mark-to-market gains (losses)	504	515	(11)	(2.1)%	(288)	803	n.m.
Other [(e)]	263	(364)	627	n.m.	146	(510)	n.m.
Total revenue net of purchased power and fuel expense	$7,433	$7,376	$ 57	0.8%	$6,858	$ 518	7.6%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.

(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at merger date of $488 million and $1,098 million pre-tax for the twelve months ended December 31, 2013 and December 31, 2012, respectively.
(f) Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. Includes $487 million and $306 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2012. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

			2013 vs. 2012			2012 vs. 2011	
Supply source (GWh)	2013	2012 [a]	Variance	% Change	2011	Variance	% Change
Nuclear generation [b]							
Mid-Atlantic	48,881	47,337	1,544	3.3%	47,287	50	0.1%
Midwest	93,245	92,525	720	0.8%	92,010	515	0.6%
	142,126	139,862	2,264	1.6%	139,297	565	0.4%
Fossil and renewables [b]							
Mid-Atlantic [b][d]	11,714	8,808	2,906	33.0%	7,572	1,236	16.3%
Midwest	1,478	971	507	52.2%	596	375	62.9%
New England	10,896	9,965	931	9.3%	8	9,957	n.m.
ERCOT	6,453	6,182	271	4.4%	2,030	4,152	n.m.
Other Regions [e]	6,664	5,913	751	12.7%	1,432	4,481	n.m.
	37,205	31,839	5,366	16.9%	11,638	20,201	n.m.
Purchased power							
Mid-Atlantic [c]	14,092	20,830	(6,738)	(32.3)%	2,898	17,932	n.m.
Midwest	4,408	9,805	(5,397)	(55.0)%	5,970	3,835	64.2%
New England	7,655	9,273	(1,618)	(17.4)%	—	9,273	n.m.
New York [c]	13,642	11,457	2,185	19.1%	—	11,457	n.m.
ERCOT	15,063	23,302	(8,239)	(35.4)%	7,537	15,765	n.m.
Other Regions [e]	14,931	17,327	(2,396)	(13.8)%	2,503	14,824	n.m.
	69,791	91,994	(22,203)	(24.1)%	18,908	73,086	n.m.
Total supply by region [f]							
Mid-Atlantic [g]	74,687	76,975	(2,288)	(3.0)%	57,757	19,218	33.3%
Midwest [h]	99,131	103,301	(4,170)	(4.0)%	98,576	4,725	4.8%
New England	18,551	19,238	(687)	(3.6)%	8	19,230	n.m.
New York	13,642	11,457	2,185	19.1%	—	11,457	n.m.
ERCOT	21,516	29,484	(7,968)	(27.0)%	9,567	19,917	n.m.
Other Regions [e]	21,595	23,240	(1,645)	(7.1)%	3,935	19,305	n.m.
Total supply	249,122	263,695	(14,573)	(5.5)%	169,843	93,852	55.3%

(a) Includes results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power includes physical volumes of 12,067 GWh and 9,925 GWh in the Mid-Atlantic and 12,165 GWh and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2013 and 2012 respectively.
(d) Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Excludes physical proprietary trading volumes of 8,762 GWh, 12,958 GWh and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

(g) Includes sales to PECO through the competitive procurement process of 5,070 GWh, 7,762 GWh, and 7,041 GWh for the years ended December 31, 2013, 2012 and 2011 respectively. Sales to BGE of 5,595 GWh and 3,766 GWh were included for the years ended December 31, 2013 and 2012 respectively.
(h) Includes sales to ComEd under the RFP procurement of 7,491 GWh, 4,152 GWh and 4,731 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2013 as compared to the same period in 2012 and 2012 as compared to the same period in 2011.

$/MWh	2013	2012 (a)	2013 vs. 2012 % Change	2011	2012 vs. 2011 % Change
Mid-Atlantic (b)	$43.78	$44.60	(1.8)%	$ 58.00	(23.1)%
Midwest (c)	26.09	29.02	(10.1)%	35.99	(19.4)%
New England	9.97	10.19	(2.1)%	n.m.	n.m.
New York	(0.29)	6.63	(104.4)%	n.m.	n.m.
ERCOT	20.26	13.74	47.5%	8.78	56.5%
Other Regions (d)	9.31	5.64	65.0%	(3.56)	n.m.
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	$26.79	$27.45	(2.4)%	$41.07	(33.2)%

(a) Includes financial results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $405 million (5,070 GWh), $536 million (7,762 GWh) and $508 million (7,041 GWh) for the years ended December 31, 2013, 2012 and 2011, respectively. Sales to BGE of $455 million (5,595 GWh) and $322 million (3,766 GWh) were included for the years ended December 31, 2013 and 2012 respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.
(c) Includes sales to ComEd of $283 million (7,491 GWh), $162 million (4,152 GWh) and $179 million (4,731 GWhs) and settlements of the ComEd swap of $230 million, $627 million and $474 million for years ended December 31, 2013, 2012 and 2011, respectively.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the years ended December 31, 2013, 2012 and 2011, respectively, and excludes the mark-to-market impact of Generation's economic hedging activities.
(f) Excludes Generation's other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation's compensation under the reliability-must-run rate schedule, the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $488 million and $1,098 million, respectively.

Mid-Atlantic

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $163 million was primarily due to lower realized power prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $83 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices and increased nuclear fuel costs.

Midwest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The decrease in revenue net of purchased power and fuel expense in the Midwest of $412 million was primarily due to lower realized power prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $549 million was primarily due to lower capacity revenues, increased nuclear fuel costs, and lower realized power prices, partially offset by decreased congestion costs.

New England

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The $11 million decrease in revenue net of purchased power and fuel expense in New England is primarily due to lower realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $187 million increase in revenue net of purchased power and fuel expense in New England was the result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $80 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, partially offset by the addition of Constellation. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $76 million increase in revenue net of purchased power and fuel expense in New York was the result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased realized energy prices and the addition of Constellation in 2012, partially offset by a decrease due to the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $321 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio driven by the performance of Generation’s generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $70 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation in 2012, in addition to increased renewable generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $145 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Mark-to-market

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $504 million in 2013 compared to gains of $515 million in 2012. See Notes 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Note 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $627 million increase in other revenue net of purchased power and fuel was primarily due to reduced amortization expense of the acquired energy contracts recorded at fair value at the merger date. In addition, the increase is also attributable to results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas, and the design and construction of renewable energy facilities. These increases were partially offset by the reduction in revenues net of purchased power and fuel expense from the sale of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to increased amortization expense of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2013, as compared to 2012 and 2011, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2013	2012	2011
Nuclear fleet capacity factor [(a)]	94.1%	92.7%	93.3%
Nuclear fleet production cost per MWh [(a)]	$19.83	$19.50	$18.86

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG's nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of planned refueling outage days in 2013, partially offset by a higher number of non-refueling outage days. For 2013 and 2012, planned refueling outage days totaled 233 and 274, respectively, and non-refueling outage days totaled 75 and 73, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, partially offset by higher number of net MWhs generated resulted in a higher production cost per MWh during 2013 as compared to 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of non-refueling outage days, partially offset by a lower number of planned refueling outage days in 2012. For 2012 and 2011, planned refueling outage days totaled 274 and 283, respectively, and non-refueling outage days totaled 73 and 52, respectively. Higher nuclear fuel costs resulted in a higher production cost per MWh during 2012 as compared to 2011.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012, consisted of the following:

	Increase (Decrease)
Plant retirements and divestitures [(a)]	$ (440)
FERC settlement [(b)]	(195)
Constellation merger and integration costs	(107)
Maryland commitments	(35)
Bodily injury costs [(c)]	(16)
Nuclear refueling outage costs, including the co-owned Salem plant [(d)]	(14)
Corporate allocations [(e)]	(5)
Labor, other benefits, contracting and materials [(f)]	160
Impairment and related charges of certain generating assets	160
Midwest generation bankruptcy charges	11
Pension and non-pension postretirement benefits expense	5
Other	(18)
Decrease in operating and maintenance expense	$ (494)

(a) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(c) Reflects decreased asbestos-related bodily injury expense for 2013 compared to 2012.
(d) Reflects the impact of decreased planned refueling outage days during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger synergy savings for Exelon's corporate operations and shared service entities, partially offset by the impact of an increased share of corporate allocated costs due to the merger.
(f) Includes cost of sales of our other business activities that are not allocated to a region.

The changes in operating and maintenance expense for 2012 compared to 2011, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials (a)	$ 845
Loss on the sale of Maryland Clean Coal assets (b)	278
FERC settlement (c)	195
Constellation merger and integration costs	182
Corporate allocations (d)	175
Pension and non-pension postretirement benefits expense	76
Maryland commitments (e)	35
Nuclear refueling outage costs, including the co-owned Salem plant (f)	(52)
Other	146
Increase in operating and maintenance expense	$ 1,880

(a) Includes cost of sales of our other business activities that are not allocated to a region.
(b) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(d) Reflects an increased share of corporate allocated costs due to the merger.
(e) Reflects costs incurred as part of the Maryland order approving the merger.
(f) Reflects the impact of decreased planned refueling outages during 2012.

Depreciation and Amortization

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities and ongoing capital additions.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities; and capital additions and other upgrades to legacy plants.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase was primarily due to the addition of Constellation's financial results in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase was primarily due to the addition of Constellation's financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . Equity in earnings (losses) of unconsolidated affiliates increased primarily due to $50 million favorable net income generated from Exelon's equity investment in CENG and a reduction of $58 million of amortization of the basis difference in CENG recorded at fair value at the merger date.

Interest Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger and increased project financing.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase of $129 million in other, net primarily reflects $85 million of credit facility termination fees recorded in 2012 and increased net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2012, as described in the table below. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase of $117 million in other, net primarily reflects a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow, $32 million of interest income from a one-time NDT fund special transfer tax deduction in 2011, net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below, offset by $85 million of credit facility termination fees recorded in 2012. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2013, 2012 and 2011:

	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds	$146	$105	$ (4)
Net realized gains (losses) on sale of decommissioning trust funds	$ 24	$ 51	$(10)

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 36.7%, 47.3% and 37.4%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2013	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance	2011	Favorable (Unfavorable) 2012 vs. 2011 Variance
Operating revenues	$4,464	$5,443	$ (979)	$6,056	$ (613)
Purchased power expense	1,174	2,307	1,133	3,035	728
Revenues net of purchased power expense (a)	3,290	3,136	154	3,021	115
Other operating expenses					
Operating and maintenance	1,368	1,345	(23)	1,189	(156)
Depreciation and amortization	669	610	(59)	554	(56)
Taxes other than income	299	295	(4)	296	1
Total other operating expenses	2,336	2,250	(86)	2,039	(211)
Operating income	954	886	68	982	(96)
Other income and (deductions)					
Interest expense, net	(579)	(307)	(272)	(345)	38
Other, net	26	39	(13)	29	10
Total other income and (deductions)	(553)	(268)	(285)	(316)	48
Income before income taxes	401	618	(217)	666	(48)
Income taxes	152	239	87	250	11
Net income	$ 249	$ 379	$ (130)	$ 416	$ (37)

(a) ComEd evaluates its operating performance using the measure of revenues net of purchased power expense. ComEd believes that revenues net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenues net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012. ComEd's net income for the year ended December 31, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon's like-kind exchange tax position, partially offset by increased electric distribution revenues, including the impacts of Senate Bill 9, and increased transmission revenues. See Note 3—Regulatory Matters and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd's net income for the year ended December 31, 2012, was lower than the same period in 2011, primarily due to increased operating and maintenance expenses, partially offset by increased electric distribution revenues and increased transmission revenues.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of operating revenues that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenues net of purchased power expense. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's operating revenues related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenues net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,630,185, 1,627,150 and 380,262 at December 31, 2013, 2012 and 2011, respectively, representing 68%, 43% and 10% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81%, 65% and 56% of ComEd's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities, including governmental entities such as townships and counties, approved referenda regarding electric supply aggregation. The referenda allowed governmental officials to identify and sign contracts with competitive electric generation suppliers on behalf of the eligible retail customers in the community, while also allowing customers to opt-out of the municipal aggregation program. As of December 31, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately 69% of residential usage as of December 31, 2013 is being supplied by competitive electric generation suppliers, and ComEd estimates that over 80% of that usage resulted from municipal aggregation activities.

The changes in ComEd's revenues net of purchased power expense for the year ended 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)
Weather	$ (17)
Volume	(2)
Electric distribution revenues, including impacts of Senate Bill 9	168
Discrete impacts of the 2012 Distribution Rate Case Order	13
Transmission revenues	14
Regulatory required programs	20
Uncollectible accounts recovery, net	(58)
Other	16
Total increase	$ 154

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2013, the increase in revenues net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in 2013, compared to the same period in 2012.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2013 and 2012 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Twelve Months Ended December 31,	2013	2012	Normal	From 2012	From Normal
Heating Degree-Days	6,603	5,065	6,341	30.4%	4.1%
Cooling Degree-Days	933	1,324	842	(29.5)%	10.8%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Distribution revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the year ended December 31, 2013, ComEd recorded increased revenues of $168 million, primarily due to increased capital investments, increased operating expenses, and higher allowed return on common equity, including the impacts of Senate Bill 9. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders, discussed separately below. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. On October 3, 2012, the ICC issued its final order related to ComEd's 2011 formula rate proceeding under EIMA (Rehearing Order), which reestablished ComEd's position on the return on its pension asset, resulting in an increase to revenues in 2013. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. During the year ended December 31, 2013, ComEd recorded increased revenues of $14 million primarily due to increased capital investments and higher operating expenses. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. See the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites. Other revenues were higher during the year ended December 31, 2013, compared to the same period in 2012, primarily due to recoveries of increased environmental costs associated with MGP sites, for which an equal and offsetting amount expense is reflected in depreciation and amortization expense during the periods presented.

The changes in ComEd's revenues net of purchased power expense for 2012 compared to 2011 consisted of the following:

	Increase (Decrease)
Weather	$ 2
Volume	(4)
Electric distribution revenues	53
Discrete impacts of the 2012 Distribution Rate Case Order	(13)
Transmission revenues	40
Regulatory required programs	32
Uncollectible accounts recovery, net	(28)
Other	33
Total increase	$ 115

Weather. For the year ended December 31, 2012, revenues net of purchased power expense increased due to favorable weather conditions in 2012 compared to the same period in 2011.

The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2012 and 2011 consisted of the following:

				% Change	
Heating and Cooling Degree-Days Twelve Months Ended December 31,	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Heating Degree-Days	5,065	6,134	6,341	(17.4)%	(20.1)%
Cooling Degree-Days	1,324	1,036	842	27.8%	57.2%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2012, reflecting decreased average usage per residential customer as compared to the same period in 2011.

Electric Distribution Revenues. Under EIMA, ComEd recorded increased revenues during the year ended December 31, 2012 of $53 million, primarily due to increased capital investments and increased operating expenses, partially offset by lower allowed return on common equity. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders discussed separately below. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. The May and October 2012 ICC Distribution Rate Case Orders resulted in a reduction to revenues of $13 million in 2012 compared to the same period in 2011. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. Based on the FERC-approved formula, ComEd recorded increased revenues during the year ended December 31, 2012 of $40 million, primarily due to increased operating expenses. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Operating and Maintenance Expense

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase 2013 vs. 2012	Year Ended December 31, 2012	Year Ended December 31, 2011	Increase 2012 vs. 2011
Operating and maintenance expense—baseline	$1,202	$1,199	$ 3	$1,199	$1,075	$ 124
Operating and maintenance expense—regulatory required programs (a)	166	146	20	146	114	32
Total operating and maintenance expense	$1,368	$1,345	$ 23	$1,345	$1,189	$ 156

(a) Operating and maintenance expense for regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for year ended December 31, 2013, compared to the same period in 2012 and changes for the year ended December 31, 2012, compared to the same period in 2011, consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials (a)	$ 48	$ 95
Pension and non-pension postretirement benefits expense	3	46
Discrete impacts from 2010 Rate Case order (b)	—	32
Storm-related costs	(10)	(1)
Science and Technology Innovation Trust (c)	—	(11)
Uncollectible accounts expense—provision (d)	(10)	(14)
Uncollectible accounts expense—recovery, net (d)	(48)	(14)
Other	20	(9)
	3	124
Regulatory required programs		
Energy efficiency and demand response programs	20	33
Purchased power administrative costs	—	(1)
	20	32
Increase in operating and maintenance expense	$ 23	$ 156

(a) The increase includes contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2013 and 2012. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.
(b) ComEd recorded one-time net benefits in May 2012 as a result of the 2010 Rate Case order to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.
(c) Under EIMA, ComEd makes recurring payments for contribution to a Science and Technology Innovation Trust fund that will be used to fund energy innovation.
(d) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. In 2013, ComEd recorded a net reduction in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting reduction has been recognized in operating revenues for the periods presented.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011, consisted of the following:

	Increase 2013 vs. 2012	Increase 2012 vs. 2011
Depreciation associated with higher plant balances	$ 22	$ 22
Amortization of storm-related regulatory assets [(a)]	4	4
Amortization of MGP regulatory assets [(b)]	27	8
Amortization of other regulatory assets	6	6
Other	—	16
Increase in depreciation and amortization expense	$ 59	$ 56

(a) Under EIMA, ComEd is required to recover costs associated with significant storms over a five-year period through the amortization of a regulatory asset.
(b) An equal and offsetting amount for the amortization expense related to MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income increased primarily due to increased Illinois electricity distribution taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Taxes other than income taxes decreased primarily due to decreased Illinois electricity distribution taxes.

Interest Expense, Net

The changes in interest expense, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest expense related to uncertain tax positions [(a)]	$ 281	$ —
Interest expense on debt (including financing trusts)	2	(26)
Other	(11)	(12)
Increase (decrease) in interest expense, net	$ 272	$ (38)

(a) Primarily reflects the remeasurement of Exelon’s like-kind exchange tax position in the first quarter of 2013. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net

The changes in other, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest income related to uncertain tax positions [(a)]	$ (20)	$ 16
Gain on asset disposal	5	—
Other	2	(6)
Increase in Other, net	$ (13)	$ 10

(a) Primarily reflects a receivable recorded in the fourth quarter of 2012 related to the final 1999-2001 IRS settlement.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2013, 2012 and 2011, were 37.9%, 38.7% and 37.5%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs 2012	Weather-Normal % Change	2011	% Change 2012 vs 2011	Weather-Normal % Change
Retail Deliveries (a)							
Residential	27,800	28,528	(2.6)%	(0.6)%	28,273	0.9%	(0.6)%
Small commercial & industrial	32,305	32,534	(0.7)%	0.2%	32,281	0.8%	0.2%
Large commercial & industrial	27,684	27,643	0.1%	(0.3)%	27,732	(0.3)%	(0.3)%
Public authorities & electric railroads	1,355	1,272	6.5%	4.2%	1,235	3.0%	4.2%
Total Retail Deliveries	89,144	89,977	(0.9)%	(0.1)%	89,521	0.5%	(0.1)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	3,480,398	3,455,546	3,448,481
Small commercial & industrial	367,569	365,357	365,824
Large commercial & industrial	1,984	1,980	2,032
Public authorities & electric railroads	4,853	4,812	4,797
Total	3,854,804	3,827,695	3,821,134

Electric Revenue	2013	2012	% Change 2013 vs 2012	2011	% Change 2012 vs 2011
Retail Sales (a)					
Residential	$2,073	$3,037	(31.7)%	$3,510	(13.5)%
Small commercial & industrial	1,250	1,339	(6.6)%	1,517	(11.7)%
Large commercial & industrial	427	395	8.1%	383	3.1%
Public authorities & electric railroads	48	44	9.1%	50	(12.0)%
Total Retail Sales	3,798	4,815	(21.1)%	5,460	(11.8)%
Other Revenue (b)	666	628	6.1%	596	5.4%
Total Electric Revenues	$4,464	$5,443	(18.0)%	$6,056	(10.1)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include wholesale revenue, rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental remediation costs associated with MGP sites, and intercompany revenues.

Results of Operations—PECO

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$3,100	$3,186	$ (86)	$3,720	$ (534)
Purchased power and fuel	1,300	1,375	75	1,864	489
Revenues net of purchased power and fuel expense (a)	1,800	1,811	(11)	1,856	(45)
Other operating expenses					
Operating and maintenance	748	809	61	794	(15)
Depreciation and amortization	228	217	(11)	202	(15)
Taxes other than income	158	162	4	205	43
Total other operating expenses	1,134	1,188	54	1,201	13
Operating income	666	623	43	655	(32)
Other income and (deductions)					
Interest expense, net	(115)	(123)	8	(134)	11
Other, net	6	8	(2)	14	(6)
Total other income and (deductions)	(109)	(115)	6	(120)	5
Income before income taxes	557	508	49	535	(27)
Income taxes	162	127	(35)	146	19
Net income	395	381	14	389	(8)
Preferred security dividends	7	4	3	4	—
Net income on common stock	$ 388	$ 377	$ 11	$ 385	$ (8)

(a) PECO evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenues net of purchased power expense and revenues net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenues from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by lower operating and maintenance expense partially offset by an increase in income taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by lower operating revenues net of purchased power and fuel expense and increased storm costs. The decrease in revenues net of purchased power and fuel expense was primarily related to unfavorable weather and a decline in electric load. The decrease to net income was partially offset by lower taxes other than income, interest expense and income taxes.

Operating Revenues Net of Purchased Power and Fuel Expense

Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenues net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenues collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenues net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 531,500, 496,500, and 387,600 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 68%, 66%, and 57% of PECO's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, 53,600, and 24,800 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 19%, 16%, and 11% of PECO's mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 6	$ 31	$ 37
Volume	(3)	(3)	(6)
Pricing	(14)	2	(12)
Regulatory required programs	(6)	—	(6)
Gross receipts tax	(8)	—	(8)
Gas distribution tax repair	—	(8)	(8)
Other	(7)	(1)	(8)
Total decrease	$ (32)	$ 21	$ (11)

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

Heating and Cooling Degree-Days	2013	2012	Normal	% Change From 2012	% Change From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	4,474	3,747	4,603	19.4%	(2.8)%
Cooling Degree-Days	1,411	1,603	1,301	(12.0)%	8.5%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflects the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from higher priced classes to lower priced classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects a decline in Residential use per customer.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Gross Receipts Tax

GRT is an excise tax on total electric revenues. As a result of decreases in operating revenues compared to 2012, GRT decreased. Equal and offsetting decreases in GRT have been reflected in taxes other than income.

Gas Distribution Tax Repair

The decrease in gas distribution tax repair reflects the 2012 tax benefit received from prior period gas distribution repairs for the 2011 tax year. There is an equal and offsetting tax benefit in operating revenues, see NOTE 3—Regulatory Matters for further explanation.

Other

The decrease in other electric revenues net of purchased power expense compared to the year ended December 31, 2012 reflects a decrease in wholesale transmission revenues earned by PECO due to higher peak loads in the previous years.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (17)	$ (15)	$ (32)
Volume	(22)	—	(22)
Pricing	(4)	3	(1)
Regulatory required programs	29	—	29
Gross receipts tax	(27)	—	(27)
Other	8	—	8
Total increase (decrease)	$ (33)	$ (12)	$ (45)

Weather

Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable winter weather conditions during 2012 in PECO's service territory.

The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days [(a)]	2012	2011	Normal	% Change From 2011	% Change From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	3,747	4,157	4,603	(9.9)%	(18.6)%
Cooling Degree-Days	1,603	1,617	1,301	(0.9)%	23.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the reduced oil refinery load in PECO's service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected a decrease in GRT revenues as a result of lower supplied energy service and a reduction in the GRT rate. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Twelve Months Ended December 31, 2013	Twelve Months Ended December 31, 2012	Increase (Decrease) 2013 vs. 2012	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011	Increase (Decrease) 2012 vs. 2011
Operating and Maintenance Expense —Baseline	$ 668	$ 723	$ (55)	$ 723	$ 725	$ (2)
Operating and Maintenance Expense —Regulatory Required Programs [(a)]	80	86	(6)	86	69	17
Total Operating and Maintenance Expense	$ 748	$ 809	$ (61)	$ 809	$ 794	$ 15

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials	$ 10	$ (29)
Storm-related costs	(49)	9 [(a)]
Pension and non-pension postretirement benefits expense	(12)	—
Constellation merger and integration costs	(8)	15
Other	4	3
	(55)	(2)
Regulatory Required Programs		
Smart Meter	4	12
Energy Efficiency	(9)	8
GSA	—	(1)
Consumer education program	(1)	(1)
AEPS	—	(1)
	(6)	17
Increase (decrease) in operating and maintenance expense	$ (61)	$ 15

(a) Storm-related costs include $46 million of incremental storm costs incurred in the fourth quarter of 2012 as a result of Hurricane Sandy. This expense was significantly offset by the costs incurred related to Hurricane Irene and other storms throughout 2011.

Depreciation and Amortization Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense, net for 2013, compared to 2012 was primarily due to ongoing capital expenditures.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense, net for 2012 compared to 2011 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
GRT expense	$ (12)	$ (33)
Sales and use tax	8	(12)[(a)]
Other	—	2
Decrease in taxes other than income	$ (4)	$ (43)

(a) The decrease reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to refinancing debt at lower interest rates during the second half of 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in interest expense, net for 2012 compared to 2011 was primarily due to the debt retirement in November 2011.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Other, net remained relatively level between periods.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in Other, net for 2012 compared to 2011 was due to decreased AFUDC—Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements in the 2012 10-K for additional details of the components of Other, net.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 29.1%, 25.0% and 27.3%, respectively. The increase in effective income tax rate in 2013 compared 2012 reflects the 2012 impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,341	13,233	0.8%	(0.0)%	13,687	(3.3)%	(1.7)%
Small commercial & industrial	8,101	8,063	0.5%	(1.1)%	8,321	(3.1)%	(2.3)%
Large commercial & industrial	15,379	15,253	0.8%	1.5%	15,677	(2.7)%	(2.7)%
Public authorities & electric railroads	930	943	(1.4)%	(1.4)%	945	(0.2)%	(0.2)%
Total Electric Retail Deliveries	37,751	37,492	0.7%	0.3%	38,630	(2.9)%	(2.2)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	1,423,068	1,417,773	1,415,681
Small commercial & industrial	149,117	148,803	148,570
Large commercial & industrial	3,105	3,111	3,110
Public authorities & electric railroads	9,668	9,660	9,689
Total	1,584,958	1,579,347	1,577,050

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales (a)					
Residential	$ 1,592	$1,689	(5.7)%	$1,934	(12.7)%
Small commercial & industrial	433	462	(6.3)%	585	(21.0)%
Large commercial & industrial	224	232	(3.4)%	308	(24.7)%
Public authorities & electric railroads	30	31	(3.2)%	38	(18.4)%
Total Retail	2,279	2,414	(5.6)%	2,865	(15.7)%
Other Revenue (b)	221	226	(2.2)%	244	(7.4)%
Total Electric Revenues	$ 2,500	$2,640	(5.3)%	$3,109	(15.1)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries (b)							
Retail sales	57,613	49,767	15.8%	(0.1)%	54,239	(8.2)%	(0.1)%
Transportation and other	28,089	26,687	5.3%	0.5%	28,204	(5.4)%	(4.8)%
Total Gas Deliveries	85,702	76,454	12.1%	0.1%	82,443	(7.3)%	(1.6)%

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	458,356	454,502	451,382
Commercial & industrial	42,174	41,836	41,373
Total Retail	500,530	496,338	492,755
Transportation	909	903	879
Total	501,439	497,241	493,634

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales (a)					
Retail sales	$562	$509	10.4%	$576	(11.6)%
Transportation and other	38	37	2.7%	35	5.7%
Total Gas Revenues	$600	$546	9.9%	$611	(10.6)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations—BGE

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$3,065	$2,735	$ 330	$3,068	$ (333)
Purchased power and fuel expense	1,421	1,369	(52)	1,593	224
Revenue net of purchased power and fuel expense (a)	1,644	1,366	278	1,475	(109)
Other operating expenses					
Operating and maintenance	634	728	94	680	(48)
Depreciation and amortization	348	298	(50)	274	(24)
Taxes other than income	213	208	(5)	207	(1)
Total other operating expenses	1,195	1,234	39	1,161	(73)
Operating income	449	132	317	314	(182)
Other income and (deductions)					
Interest expense, net	(122)	(144)	22	(129)	(15)
Other, net	17	23	(6)	26	(3)
Total other income and (deductions)	(105)	(121)	16	(103)	(18)
Income before income taxes	344	11	333	211	(200)
Income taxes	134	7	(127)	75	68
Net income	210	4	206	136	(132)
Preference stock dividends	13	13	—	13	—
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 206	$ 123	$ (132)

(a) BGE evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenues net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenues from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by higher distribution rates as a result of the 2012 rate order issued by MDPSC and decreased operating revenues net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. Additionally, the increase in net income was also driven by higher operating and maintenance expenses in 2012, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger and lower storm restoration costs in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by decreased operating revenues net of purchased power and fuel expense related to the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger as well as merger transaction costs, and increased depreciation and amortization expense. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE's customers.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 399,000, 362,000 and 314,000 at December 31, 2013, 2012 and 2011, respectively, representing 32%, 29% and 25% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 61%, 60% and 58% of BGE's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 172,000, 143,000 and 118,000 at December 31, 2013, 2012 and 2011, respectively, representing 26%, 22% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 54%, 56% and 52% of BGE's retail mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
2012 Residential customer rate credit [(a)]	$ 82	$31	$ 113
Pricing	69	24	93
Regulatory program cost recovery	36	6	42
Other	26	4	30
Total increase	$ 213	$65	$278

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2013	2012	Normal	% Change From 2012	% Change From Normal
Heating Degree-Days	4,744	3,960	4,661	19.8%	1.8%
Cooling Degree-Days	869	1,022	864	(15.0)%	0.6%

2012 Residential Customer Rate Credit.

The increase in operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 was due to the residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation.

Pricing.

The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 and December 13, 2013 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs.

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency program costs.

Other.

Other revenues increased during the year ended December 31, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
2012 Residential customer rate credit	$ (82)	$ (31)	$ (113)
Commodity margin	(1)	(5)	(6)
Regulatory program cost recovery	15	4	19
Transmission	11	—	11
Other	(13)	(7)	(20)
Total decrease	$ (70)	$ (39)	$ (109)

The changes in heating and cooling degree days for the twelve months ended 2012 and 2011, consisted of the following:

Heating and Cooling Degree-Days [(a)]				% Change	
Twelve Months Ended December 31,	2012	2011	Normal	From 2011	From Normal
Heating Degree-Days	3,960	4,326	4,711	(8.5)%	(15.9)%
Cooling Degree-Days	1,022	1,035	858	(1.3)%	19.1%

2012 Residential Customer Rate Credit

The residential customer rate credit provided as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel expense for the year ended December 31, 2012.

Commodity Margin

The commodity margin for both electric and gas revenues decreased during the year ended December 31, 2012 compared to the same period in 2011 due to an increase in the number of customers using competitive suppliers in 2012.

Regulatory Required Programs

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency programs costs.

Transmission

Transmission revenues increased during the year ended December 31, 2012 compared to the same period in 2011 due to higher revenue requirements. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Charitable contributions [a]	$ (28)	$ 28
Storm costs deferral [b]	—	16
Storm-related costs [c]	(62)	7
Pension and non-pension postretirement benefits expense	—	6
Labor, other benefits, contracting and materials	20	(10)
Merger transaction costs [a]	(21)	(9)
Other	(3)	10
(Decrease) Increase in operating and maintenance expense	$ (94)	$ 48

(a) During the first quarter of 2012, BGE accrued $28 million in charitable contributions as a result of BGE's merger-related commitments. The charitable contribution accrual and merger costs are not recoverable from BGE's customers.
(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.
(c) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million are capital costs. These amounts compare to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene, of which $25 million are capital costs, and $14 million of incremental expenses, of which $3 are capital costs, incurred during the first quarter of 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Depreciation expense [a]	$18	$ 20
Regulatory asset amortization [b]	31	6
Other	1	(2)
Increase in depreciation and amortization expense	$50	$ 24

(a) Deprecation and amortization expense increased due to higher plant balances year over year.
(b) Regulatory asset amortization increased due to higher energy efficiency and demand response programs expenditures year over year

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Property tax	$ (2)	$ 4
Franchise tax	7	(1)
Other	—	(2)
Increase in taxes other than income	$ 5	$ 1

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to the interest recorded in 2012 on prior year tax liabilities and lower effective interest rates as a result of the refinancing of debt at a lower interest rate in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense, net in 2012 compared to 2011 was primarily due to higher outstanding debt balances and interest recorded in 2012 on prior year tax liabilities.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 39.0%, 63.6% and 35.5%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,077	12,719	2.8%	n.m.	12,652	0.5%	n.m.
Small commercial & industrial [(c)]	3,035	2,990	1.5%	n.m.	3,023	(1.1)%	n.m.
Large commercial & industrial [(c)]	14,339	14,956	(4.1)%	n.m.	15,729	(4.9)%	n.m.
Public authorities & electric railroads	317	329	(3.6)%	n.m.	405	(18.8)%	n.m.
Total Electric Retail Deliveries	30,768	30,994	(0.7)%	n.m.	31,809	(2.6)%	n.m.

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	1,120,431	1,116,233	1,116,401
Small commercial & industrial [(c)]	112,850	112,994	113,026
Large commercial & industrial [(c)]	11,652	11,580	11,365
Public authorities & electric railroads	292	319	326
Total	1,245,225	1,241,126	1,241,118

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [(a)]					
Residential	$1,404	$1,274	10.2%	$1,456	(12.5)%
Small commercial & industrial [(c)]	257	248	3.6%	268	(7.5)%
Large commercial & industrial [(c)]	439	393	11.7%	416	(5.5)%
Public authorities & electric railroads	31	30	3.3%	29	3.4%
Total Retail	2,131	1,945	9.6%	2,169	(10.3)%
Other Revenue [(b)]	274	238	15.1%	152	56.6%
Total Electric Revenues	$2,405	$2,183	10.2%	$2,321	(5.9)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes wholesale transmission revenue and late payment charges.
(c) Certain commercial and industrial (C&I) customers were reclassified from small C&I to large C&I in prior years to conform to the current year's classification of C&I customers.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [(d)]							
Retail sales	94,020	86,946	8.1%	n.m.	94,800	(8.3)%	n.m.
Transportation and other [(e)]	12,210	15,751	(22.5)%	n.m.	16,436	(4.2)%	n.m.
Total Gas Deliveries	106,230	102,697	3.4%	n.m.	111,236	(7.7)%	n.m.

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	611,532	610,827	608,943
Commercial & industrial	44,162	44,228	44,211
Total	655,694	655,055	653,154

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [(d)]					
Retail sales	$592	$494	19.8%	$ 580	(14.8)%
Transportation and other [(e)]	68	58	17.2%	92	(37.0)%
Total Gas Revenues	$660	$ 552	19.6%	$672	(17.9)%

(d) Reflects delivery revenues and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.
(e) Transportation and other gas revenue includes off-system revenue of 12,210 mmcfs ($55 million), 15,751 mmcfs ($51 million), and 16,436 mmcfs ($82 million) for the years ended 2013, 2012 and 2011, respectively.

Liquidity and Capital Resources

Exelon's and Generation's prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity presented below includes its activity for the 12 months ended December 31, 2012 and 2011.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities are in place until 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks which expire in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 13 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to contribute approximately $264 million to its pension plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $118 million, $119 million, $11 million and $0 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2013 and 2012 pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued recovery). Exelon expects to contribute approximately $430 million to the other postretirement benefit plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $168 million, $197 million, $19 million and $17 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2013 and 2012 other postretirement benefit contributions.

See the "Contractual Obligations" section below for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon, Generation, ComEd, PECO and BGE expect to receive tax refunds of approximately $380 million, $60 million, $320 million, $10 million and $20 million, respectively, between 2014 and 2015.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.
- In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit in 2012 of approximately $38 million and $41 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue industry guidance in the near future. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion regarding the regulatory treatment of PECO's tax benefits from the application of the method change.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2013 vs. 2012 Variance	2011	2012 vs. 2011 Variance
Net income	$1,729	$1,171	$ 558	$ 2,499	$ (1,328)
Add (subtract):					
Non-cash operating activities (a)	4,159	5,588	(1,429)	4,848	740
Pension and non-pension postretirement benefit contributions	(422)	(462)	40	(2,360)	1,898
Income taxes	883	544	339	492	52
Changes in working capital and other noncurrent assets and liabilities (b)	(185)	(731)	546	(279)	(452)
Option premiums paid, net	(36)	(114)	78	(3)	(111)
Counterparty collateral received (paid), net	215	135	80	(344)	479
Net cash flows provided by operations	$6,343	$6,131	$ 212	$ 4,853	$ 1,278

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon (a)	$6,343	$6,131	$4,853
Generation (a)	3,887	3,581	3,313
ComEd	1,218	1,334	836
PECO	747	878	818
BGE (a)	561	485	476

(a) Exelon's and Generation's prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for 2013, 2012 and 2011 were as follows:

Generation

- During 2013, 2012 and 2011, Generation had net (payments) receipts of counterparty collateral of $162 million, $95 million and $(410) million, respectively. Net payments during 2013 and 2012 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During 2013, 2012 and 2011, Generation's accounts receivable from ComEd increased (decreased) by $(16) million, $(15) million and $12 million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.

- During 2013, 2012 and 2011, Generation's accounts receivable from PECO increased (decreased) by $(17) million, $17 million and $(210) million, respectively.
- During 2013, 2012 and 2011, Generation's accounts receivable from BGE increased (decreased) by $(4) million, $23 million and $(13) million, respectively.
- During 2013, 2012 and 2011, Generation had net payments of approximately $36 million, $114 million and $3 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2013, 2012 and 2011, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements increased (decreased) by $(16) million, $(15) million and $12 million, respectively. During 2013, 2012 and 2011, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $35 million, $20 million and $(43) million, respectively.
- During 2013, 2012, and 2012, ComEd received $53 million, $37 million and $63 million, respectively, of incremental cash collateral from PJM due to variations in its energy transmission activity levels. As of December 31, 2013 and December 31, 2012, ComEd had cash collateral remaining at PJM of $0M and $53 million, respectively.

PECO

- During 2013, 2012 and 2011, PECO's payables to Generation for energy purchases increased (decreased) by $(17) million, $17 million and $(210) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $33 million, $(22) million and $97 million, respectively.

BGE

- During 2013, 2012 and 2011, BGE's payables to Generation for energy purchases increased (decreased) by $(4) million, $23 million and $(13) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $5 million, $40 million and $(60) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2013, 2012, and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon (a)(c)(f)	$(5,394)	$(4,576)	$(4,603)
Generation (a)(c)(f)	(2,916)	(2,629)	(3,077)
ComEd	(1,387)	(1,212)	(1,007)
PECO	(531)	(328)	(557)
BGE (f)	(571)	(573)	(592)

Capital expenditures by Registrant for 2013, 2012 and 2011 and projected amounts for 2014 are as follows:

	Projected 2014 [b]	2013	2012	2011 [a]
Exelon [f]	$5,475	$5,395	$5,789	$4,042
Generation [c][f]	2,400	2,752	3,554	2,491
ComEd [d]	1,775	1,433	1,246	1,028
PECO	625	537	422	481
BGE [f]	600	587	582	592
Other [e]	75	86	82	42

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Total projected capital expenditures do not include adjustments for non-cash activity.
(c) Includes nuclear fuel.
(d) Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. ComEd expects to file an updated investment plan with the ICC in April, 2014.
(e) Other primarily consists of corporate operations and BSC.
(f) Exelon's and Generation's prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 38% and 11% of the projected 2014 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2014 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. See "EXELON CORPORATION—Executive Overview," for more information on nuclear uprates.

On November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC, and received net proceeds of approximately $371. In addition, Generation will begin to make cash payments of approximately $31 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2014. In 2012, Generation incurred transaction costs of approximately $15 million through the date of closing of the transaction. The sale will generate approximately $195 million of cash tax benefits, of which $155 million will be realized in periods through 2014 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $495 million through 2014 and approximately $36 million in subsequent years.

ComEd, PECO and BGE

Approximately 91%, 72% and 89% of the projected 2014 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. ComEd's capital expenditures include smart grid/smart meter technology required under EIMA. PECO and BGE capital expenditures include investments related to their respective smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth. See Notes 3 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners, including ComEd, PECO, and BGE, that recommends the completion of performance assessments of their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will incur incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2014 capital expenditures above reflect capital spending for remediation to be completed in 2014.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$(826)	$(1,085)	$(846)
Generation	(384)	(777)	(196)
ComEd	61	(212)	355
PECO	(361)	(382)	(589)
BGE	(48)	128	115

Debt.Debt activity for 2013, 2012 and 2011 by Registrant was as follows:

Company	Issuances of long-term debt in 2013	Use of proceeds
Generation	$5 million of variable rate CEU Credit Agreement project financing, due July 22, 2016	Used to fund Upstream gas activities
Generation	$227 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$1 million of 2.93% Social Security Administration Project Financing, due February 18, 2015	Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	$9 million of 4.40% Energy Efficiency Financing, due August 31, 2014	Used for funding to install energy conservation measures in Beckley, West Virginia
Generation	$613 million of 6.00% Continental Wind Senior Secured Notes, due February 28, 2033	Used for general corporate purposes

Company	Issuances of long-term debt in 2013	Use of proceeds
ComEd	$350 million of First Mortgage 4.60% Bonds, Series 114, due August 15, 2043	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$300 million of First and Refunding Mortgage 1.20% Bonds due October 15, 2016	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	$250 million of First and Refunding Mortgage 4.80% Bonds due October 15, 2043	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	$300 million of fixed rate 3.35% Notes due July 1, 2023	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

Company	Issuances of long-term debt in 2012	Use of proceeds
Generation	$78 million of variable rate CEU Credit Agreement project financing, due July 16, 2016	Used to fund Upstream gas activities
Generation	$220 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$523 million of 4.25% Senior Notes due June 15, 2022	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$788 million of 5.60% Senior Notes due June 15, 2042	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$38 million of variable rate Clean Horizons project financing due June 7, 2030	Used for funding for Maryland solar development
ComEd	$350 million of First Mortgage 3.80% Bonds, Series 113, due October 1, 2042	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$350 million of First and Refunding Mortgage 2.38% Bonds due September 15, 2022	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	$250 million of fixed rate 2.80% Notes due August 15, 2022	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$600 million of First Mortgage 1.625% Bonds, Series 110, due January 15, 2014	Used as an interim source of liquidity for a January 2011 contribution to Exelon-sponsored pension plans
ComEd	$250 million of First Mortgage 1.95% Bonds, Series 111, due September 1, 2016	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$350 million of First Mortgage 3.40% Bonds, Series 112, due September 1, 2021	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes
BGE	$300 million of fixed rate 3.50% Notes, due November 15, 2021	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Retirement of long-term debt in 2013
Generation	$3 million scheduled payments of 7.83% Kennett Square capital lease until September 1, 2020
Generation	$113 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$2 million of 2.563% project financing Clean Horizons with a final maturity of September 7, 2030
Generation	$2 million of 2.68% Sacramento Energy Loan Agreement with a final maturity of December 31, 2030
Generation [(a)]	$450 million of 8.625% Series A Junior Subordinated Debentures with a final maturity of June 15, 2063
ComEd	$125 million of 7.625% First Mortgage Bonds, Series 92, due April 15, 2013
ComEd	$127 million of 7.500% First Mortgage Bonds, Series 94, due July 1, 2013
PECO	$300 million of 5.600% First and Refunding Mortgage Bonds, due October 15, 2013
BGE	$67 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2017
BGE	$400 million of 6.125% Senior Notes, due July 1, 2013

Company	Retirement of long-term debt in 2012
Exelon	$2 million of 7.30% fixed-rate Medium Term Notes with a maturity date of June 1, 2012
Exelon	$442 million of 7.60% fixed-rate Senior Notes with a maturity date of April 1, 2032
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$46 million of 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes at 5.00% with a final maturity of December 1, 2042
Generation	$89 million of variable rate project financing CEU Credit Agreement with a final maturity of July 16, 2016
Generation	$17 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$75 million of variable rate MEDCO tax-exempt bonds with a final maturity of April 1, 2024
Generation	$2 million of variable rate Sacramento Solar Promissory Note with a final maturity of March 12, 2012
ComEd	$450 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012

Company	Retirement of long-term debt in 2012
PECO	$225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012
PECO	$150 million of 4.00% First and Refunding Mortgage Bonds, due December 1, 2012
BGE	$8 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2016
BGE	$55 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
BGE	$110 million of variable rate Medium Term Notes, due June 15, 2012

Company	Retirement of long-term debt in 2011
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$2 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 1, 2021
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017
ComEd	$345 million of 5.40% First Mortgage Bonds, Series 105, due December 15, 2011
PECO	$250 million of 5.95% First and Refunding Mortgage Bonds, due November 1, 2011
BGE	$60 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation's Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon's Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends. Cash dividend payments and distributions during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$1,263	$1,733	$1,397
Generation	625	1,626	172
ComEd	220	105	300
PECO	333	347	352
BGE	13	13	98(a)

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

Revised Dividend Policy

On February 6, 2013, the Exelon board of directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon's common stock.

Third Quarter 2013 Dividend

On July 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on September 10, 2013 of $0.310 per share on Exelon's common stock.

Fourth Quarter 2013 Dividend

On October 22, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on December 10, 2013 of $0.310 per share on Exelon's common stock

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 13	$ (52)	$—
ComEd	184	—	—
BGE	135	—	—
Other (a)	—	(140)	161
Exelon	$332	$(192)	$161

(a) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2013, 2012 and 2011 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 26	$48	$ 30
ComEd (a)	176	11	11
PECO	27	9	18
BGE	—	66	—

(a) In 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction.

Other. Other significant financing activities for Exelon for 2013, 2012 and 2011 were as follows:

- Exelon received proceeds from employee stock plans of $47 million, $72 million and $38 million during 2013, 2012 and 2011, respectively.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013, and of which no financial institution has more than 8% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2013 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A Risk Factors for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2013, it would have been required to provide incremental collateral of $2.0 billion of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit ratings as of December 31, 2013, it would have been required to provide incremental collateral of $6 million, which is well within its current available credit facility capacity of $816 million, which takes into account commercial paper borrowings as of December 31, 2013. If PECO lost its investment grade credit rating as of December 31, 2013 it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of $42 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of December 31, 2013, it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $85 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $465 million.

Exelon Credit Facilities

See Note 13 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure. At December 31, 2013, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	44%	30%	42%	40%	42%
Long-term debt to affiliates (a)	2%	8%	2%	4%	5%
Common equity	53%	—	55%	56%	49%
Member's equity	—	62%	—	—	—
Preference Stock	—	—	—	—	4%
Commercial paper and notes payable	1%	—	1%	—	—

(a) Includes approximately $648 million, $206 million, $184 million and $258 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participants during the year ended December 31, 2013, in addition to the net contribution or borrowing as of December 31, 2013, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2013 Contributed (Borrowed)
Generation	$ 159	$ 435	$ 44
PECO	304	—	—
BSC	—	287	(223)
Exelon Corporate	237	—	179

Investments in Nuclear Decommissioning Trust Funds. Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. The Registrants maintain a combined shelf registration statement unlimited in amount, with the SEC. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. The issuance by ComEd, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC.

As of December 31, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $218 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2013, ComEd requested and received $1 billion in new money financing authority from the ICC. The authority is effective on January 1, 2014 and expires January 1, 2017. As of December 31, 2013, PECO had $1.4 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd's, PECO's and BGE's short-term financings and all of Generation's financings. As of December 31, 2013, ComEd, PECO had BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion and $700 million, respectively. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation's undistributed earnings of $3,613 million, ComEd's retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $649 million and BGE's retained earnings $1,005 million. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2013 under existing contractual obligations, including payments due by period. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt (a)	$19,367	$1,424	$ 2,953	$2,731	$ 12,259	$ —
Interest payments on long-term debt (b)	12,845	925	1,692	1,396	8,832	—
Liability and interest for uncertain tax positions (c)	1,255	—	—	—	—	1,255
Capital leases	41	4	8	10	19	—
Operating leases (d)	826	103	180	145	398	—
Purchase power obligations (e)	3,046	1,378	852	367	449	—
Fuel purchase agreements (f)	9,606	1,520	2,622	1,967	3,497	—
Electric supply procurement (f)	1,880	1,062	678	140	—	—
AEC purchase commitments (f)	6	1	2	2	1	—
Curtailment services commitments (f)	132	45	74	13	—	—
Long-term renewable energy and REC commitments (g)	1,589	72	150	160	1,207	—
PJM regional transmission expansion commitments (h)	1,019	208	597	214	—	—
Spent nuclear fuel obligation	1,021	—	—	—	1,021	—
Pension minimum funding requirement (i)	1,223	264	444	426	89	—
Total contractual obligations	$53,856	$7,006	$10,252	$7,571	$ 27,772	$1,255

(a) Includes $648 million due after 2016 to ComEd, PECO and BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.
(c) As of December 31, 2013, Exelon's liability for uncertain tax positions and related interest payable was $906 million and $349 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.
(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.
(e) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2013, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements.
(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.
(g) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the

ICC's December 19, 2012 order, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(i) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2019 are not included. See Note 16 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt	$ 7,519	$ 557	$ 628	$ 701	$ 5,633	$ —
Interest payments on long-term debt [(a)]	5,362	368	693	625	3,676	—
Liability and interest for uncertain tax benefits [(b)]	264	—	—	—	—	264
Capital leases	33	4	8	10	11	—
Operating leases [(c)]	571	49	98	88	336	—
Purchase power obligations [(d)]	3,046	1,378	852	367	449	—
Fuel purchase agreements [(e)]	8,490	1,212	2,296	1,807	3,175	—
Spent nuclear fuel obligation	1,021	—	—	—	1,021	—
Total contractual obligations	$26,306	$3,568	$ 4,575	$3,598	$ 14,301	$264

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013.

(b) As of December 31, 2013, Generation's liability for uncertain tax positions and related interest payable was $227 million and $37 million, respectively. Generation was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.

(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.

(d) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2013. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 22 of the Combined Notes to Consolidated Financial Statements.

(e) See Note 22 of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.

ComEd

	Total	Payment due within 2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt (a)	$ 5,892	$ 617	$ 925	$1,265	$ 3,085	$ —
Interest payments on long-term debt (b)	3,704	274	515	393	2,522	—
Liability and interest for uncertain tax positions (c)	498	—	—	—	—	498
Capital leases	8	—	—	—	8	—
Operating leases	47	13	22	9	3	—
Electric supply procurement	736	323	273	140	—	—
Long-term renewable energy and associated REC commitments (d)	1,589	72	150	160	1,207	—
PJM regional transmission expansion commitments (e)	486	134	350	2	—	—
Total contractual obligations	$12,960	$1,433	$2,235	$1,969	$ 6,825	$498

(a) Includes $206 million due after 2017 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013. Includes estimated interest payments due to the ComEd financing trust.
(c) As of December 31, 2013, ComEd's liability for uncertain tax positions and related interest payable was $324 million and $174 million, respectively. ComEd was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's December 19, 2012 order, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Total	Payment due within 2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt (a)	$2,384	$ 250	$ 300	$ 500	$ 1,334	$—
Interest payments on long-term debt (b)	1,505	104	189	160	1,052	—
Operating leases	25	13	6	6	—	—
Fuel purchase agreements (c)	507	179	210	52	66	—
Electric supply procurement (c)	681	590	91	—	—	—
AEC purchase commitments (c)	14	2	4	4	4	—
PJM regional transmission expansion commitments (d)	133	32	69	32	—	—
Total contractual obligations	$5,249	$1,170	$869	$754	$ 2,456	$—

(a) Includes $184 million due after 2017 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

(d) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt (a)	$2,273	$ —	$ 300	$265	$ 1,708	$—
Interest payments on long-term debt (b)	1,608	112	220	162	1,114	—
Operating leases	61	12	20	15	14	—
Fuel purchase agreements (c)	609	129	116	108	256	—
Electric supply procurement (c)	1,256	783	473	—	—	—
Curtailment services commitments (c)	132	45	74	13	—	—
PJM regional transmission expansion commitments (d)	400	42	178	180	—	—
Total contractual obligations	$6,339	$1,123	$1,381	$743	$ 3,092	$—

(a) Includes $258 million due after 2017 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

See Note 22 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 22 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 15 and 22 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 1 of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 22 of the Combined Notes to Consolidated Financial Statements.

• new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the risk oversight committee of the Exelon board of directors on the scope of the risk management activities.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2014 through 2016.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015 and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2013, market conditions and hedged position would be a decrease in pre-tax net income of approximately $30 million, $520 million and $820 million, respectively, for 2014, 2015 and 2016. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 8,762 GWh, 12,958 GWh, and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2013, resulted in pre-tax losses of $8 million due to net mark-to-market losses of $39 million and realized gains of $31 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $1.0 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2013 of $7,433 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 of the Combined Notes to the Consolidated Financial Statements. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's mark-to-market net asset or liability balance sheet position from January 1, 2012, to December 31, 2013. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 12 of the Combined Notes to the Consolidated Financial Statements for more information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2013, and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations [(b)]	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2012 [(a)]	$ 1,648	$ (800)	$ —	$ 848
Contracts acquired at merger date [(c)]	140	—	—	140
Total change in fair value during 2012 of contracts recorded in result of operations	(159)	—	7	(152)
Reclassification to realized at settlement of contracts recorded in results of operations	775	—	—	775
Ineffective portion recognized in income [(d)]	(5)	—	—	(5)
Reclassification to realized at settlement from accumulated OCI [(e)]	(1,368)	—	621	(747)
Effective portion of changes in fair value—recorded in OCI [(f)]	719	—	(146)	573
Changes in fair value—energy derivatives [(g)]	—	507	(482)	25
Changes in allocated collateral	(89)	—	—	(89)
Changes in net option premium paid/(received)	114	—	—	114
Option premium amortization [(h)]	(160)	—	—	(160)
Intercompany elimination of existing derivative contracts with Constellation	(103)	—	—	(103)
Other balance sheet reclassifications	(7)	—	—	(7)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012 [(a)]	$ 1,505	$(293)	$ —	$1,212
Total change in fair value during 2013 of contracts recorded in result of operations	444	—	(6)	438
Reclassification to realized at settlement of contracts recorded in results of operations	21	—	13	34
Reclassification to realized at settlement from accumulated OCI [(e)]	(683)	—	219	(464)
Changes in fair value—energy derivatives [(g)]	—	100	(226)	(126)
Changes in allocated collateral	(175)	—	—	(175)
Changes in net option premium paid/(received)	36	—	—	36
Option premium amortization [(h)]	(104)	—	—	(104)
Other balance sheet reclassifications	4	—	—	4
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 (a) [(i)]	$ 1,048	$ (193)	$ —	$ 855

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to the five-year financial swap between Generation and ComEd.
(c) For Generation, includes $660 million of collateral paid to counterparties, offset by $520 million of unrealized losses on commodity derivative positions.

(d) For Generation, reflects $5 million of changes in cash flow hedge ineffectiveness.
(e) For Generation, includes $219 million and $621 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2013 and 2012, respectively.
(f) For Generation, includes $146 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the year ended 2012. Effective prior to the merger with Constellation, the five-year financial swap between Generation and ComEd was de-designated as a cash flow hedge. As a result, all changes in fair value for the year ended December 31, 2013 were recorded to operating revenues and eliminated in consolidation.
(g) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2013 and 2012, ComEd recorded a regulatory liability of $193 million and $293 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2013 and 2012, this includes $11 million of decreases and $98 million of increases in fair value, respectively, and $215 million and $566 million, respectively, for reclassifications from regulatory assets to recognize cost in purchase power expense due to settlements of ComEd's five-year financial swap with Generation. As of December 31, 2013 and 2012 ComEd also recorded $126 million and $34 million, respectively, of increases in fair value, and $7 million and $5 million, respectively, of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(h) Includes $104 million and $160 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2013 and 2012, respectively.
(i) Includes the ending balance related to interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 11—Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts (a)(b):							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$ —	$ (45)
Prices provided by external sources (Level 2)	444	143	39	—	—	1	627
Prices based on model or other valuation methods (Level 3) (c)	155	151	71	25	(22)	(108)	272
Total	$569	$268	$127	$ 21	$(24)	$ (107)	$ 854

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $144 million at December 31, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$ —	$ (45)
Prices provided by external sources (Level 2)	444	143	39	—	—	1	627
Prices based on model or other valuation methods (Level 3)	172	170	89	43	(4)	(5)	465
Total	$586	$287	$145	$ 39	$ (6)	$ (4)	$ 1,047

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $144 million at December 31, 2013.

ComEd

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) [(a)]	$(17)	$(19)	$(18)	$(18)	$(18)	$ (103)	$(193)

(a) Represents ComEd’s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12 of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $38 million, $38 million and $27 million, respectively. See Note 25 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral (a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,621	$ 172	$ 1,449	1	$ 491
Non-investment grade	27	9	18	—	—
No external ratings					
Internally rated—investment grade	416	1	415	1	226
Internally rated—non-investment grade	30	2	28	—	—
Total	$ 2,094	$ 184	$ 1,910	2	$ 717

Rating as of December 31, 2013	Maturity of Credit Risk Exposure			
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,146	$ 340	$ 135	$ 1,621
Non-investment grade	23	4	—	27
No external ratings				
Internally rated—investment grade	272	138	6	416
Internally rated—non-investment grade	30	—	—	30
Total	$ 1,471	$ 482	$ 141	$ 2,094

Net Credit Exposure by Type of Counterparty	As of December 31, 2013
Financial Institutions	$ 256
Investor-owned utilities, marketers and power producers	684
Energy cooperatives and municipalities	907
Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2013, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2013.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2013, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Maryland Public Utilities Article and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2013.

BGE’s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier’s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier’s lowest credit rating from the major credit rating agencies and the supplier’s tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier’s unsecured credit limit. The seller’s credit exposure is calculated each business day. As of December 31, 2013, BGE had no net credit exposure with suppliers.

BGE’s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE’s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers’ demands, which are not covered by the gas cost adjustment clause. At December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation’s net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 12 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2013, Generation had cash collateral of $72 million posted and cash collateral held of $206 million for counterparties with derivative positions, of which $144 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2013, $10 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2012, Generation had cash collateral held of $499 million and cash collateral posted of $527 million for counterparties with derivative positions, of which $31 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2012, $3 million of cash collateral received was not offset against net mark-to-market assets and liabilities because it was not associated with energy-related derivatives. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2013, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash for both annual and long-term renewable energy contracts. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheet, as of December 31, 2013, included a $698 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $1,465 million, less unearned income of $767 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third-party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline resulting in a $14 million pre-tax impairment charge in the second quarter of 2013. See Note 8 of the Combined Notes to Consolidated Financial Statements for further information. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

Interest-Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the

Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2013.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2013, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $482 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Generation

General

Generation operates in six segments: Mid-Atlantic, Midwest, New England, New York, ERCOT, and Other Regions in Generation. The operation of all six segments consists of owned contracted and investments in electric generating facilities, and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and investments in natural gas exploration and production activities. These segments are discussed in further detail in "ITEM 1. BUSINESS —Generation" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared To Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of Generation's results of operations for 2013 compared to 2012 and 2012 compared to 2011 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of ComEd's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2013, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk— Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of PECO's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2013, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS—BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of BGE's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2013, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2013, Exelon's internal control over financial reporting was effective.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2013, Generation's internal control over financial reporting was effective.

The effectiveness of the Generation's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2013, ComEd's internal control over financial reporting was effective.

The effectiveness of the ComEd's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2013, PECO's internal control over financial reporting was effective.

The effectiveness of the PECO's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2013, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our audits (which was an integrated audit in 2012). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2013	2012	2011
Operating revenues	$24,888	$23,489	$19,063
Operating expenses			
Purchased power and fuel	9,468	9,121	7,130
Purchased power and fuel from affiliates	1,256	1,036	137
Operating and maintenance	7,270	7,961	5,184
Depreciation and amortization	2,153	1,881	1,347
Taxes other than income	1,095	1,019	785
Total operating expenses	21,242	21,018	14,583
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	3,656	2,380	4,479
Other income and (deductions)			
Interest expense, net	(1,315)	(891)	(701)
Interest expense to affiliates, net	(41)	(37)	(25)
Other, net	473	346	203
Total other income and (deductions)	(883)	(582)	(523)
Income before income taxes	2,773	1,798	3,956
Income taxes	1,044	627	1,457
Net income	1,729	1,171	2,499
Net income attributable to non-controlling interests, preferred security dividends and preference stock dividends	10	11	4
Net income attributable to common shareholders	1,719	1,160	2,495
Comprehensive income (loss), net of income taxes			
Net income	1,729	1,171	2,499
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs, net of taxes of $0, $1 and $(4), respectively	—	1	(5)
Actuarial loss reclassified to periodic cost, net of taxes of $133, $110 and $93, respectively	208	168	136
Transition obligation reclassified to periodic cost, net of taxes of $0, $2 and $2, respectively	—	2	4
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $430, $(237) and $(171), respectively	669	(371)	(250)
Unrealized gain (loss) on cash flow hedges, net of taxes of $(166), $(68) and $39, respectively	(248)	(120)	88
Unrealized gain (loss) on marketable securities, net of taxes of $0, $(1) and $0, respectively	2	2	—
Unrealized gain (loss) on equity investments, net of taxes of $71, $1 and $0, respectively	106	1	—
Unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	(10)	—	—
Other comprehensive income (loss)	727	(317)	(27)
Comprehensive income	$ 2,456	$ 854	$ 2,472
Average shares of common stock outstanding:			
Basic	856	816	663
Diluted	860	819	665
Earnings per average common share:			
Basic	$ 2.01	$ 1.42	$ 3.76
Diluted	$ 2.00	$ 1.42	$ 3.75
Dividends per common share	$ 1.46	$ 2.10	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 1,729	$ 1,171	$ 2,499
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	3,779	4,079	2,316
Loss on sale of three Maryland generating stations	—	272	—
Deferred income taxes and amortization of investment tax credits	119	615	1,457
Net fair value changes related to derivatives	(445)	(604)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	876	1,383	770
Changes in assets and liabilities:			
Accounts receivable	(97)	243	57
Inventories	(100)	26	(58)
Accounts payable, accrued expenses and other current liabilities	(90)	(632)	(254)
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral received (posted), net	215	135	(344)
Income taxes	883	544	492
Pension and non-pension postretirement benefit contributions	(422)	(462)	(2,360)
Other assets and liabilities	102	(368)	(24)
Net cash flows provided by operating activities	6,343	6,131	4,853
Cash flows from investing activities			
Capital expenditures	(5,395)	(5,789)	(4,042)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation	—	964	—
Acquisitions of long lived assets	—	(21)	(387)
Proceeds from sale of long-lived assets	32	371	—
Proceeds from sales of investments	22	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(43)	(34)	(3)
Distribution from CENG	115	—	—
Other investing activities	112	136	20
Net cash flows used in investing activities	(5,394)	(4,576)	(4,603)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	—
Changes in short-term debt	332	(197)	161
Issuance of long-term debt	2,055	2,027	1,199
Retirement of long-term debt	(1,589)	(1,145)	(789)
Redemption of preferred securities	(93)	—	—
Dividends paid on common stock	(1,249)	(1,716)	(1,393)
Proceeds from employee stock plans	47	72	38
Other financing activities	(119)	(111)	(62)
Net cash flows used in financing activities	(826)	(1,085)	(846)
Increase (decrease) in cash and cash equivalents	123	470	(596)
Cash and cash equivalents at beginning of period	1,486	1,016	1,612
Cash and cash equivalents at end of period	$ 1,609	$ 1,486	$ 1,016

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,547	$ 1,411
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and investments	87	86
Restricted cash and investments of variable interest entities	80	47
Accounts receivable, net		
Customer ($0 and $289 gross accounts receivables pledged as collateral as of December 31, 2013 and December 31, 2012, respectively)	2,721	2,795
Other	1,175	1,141
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	276	246
Materials and supplies	829	768
Deferred income taxes	573	131
Regulatory assets	760	764
Other	666	560
Total current assets	10,137	10,140
Property, plant and equipment, net	47,330	45,186
Deferred debits and other assets		
Regulatory assets	5,910	6,497
Nuclear decommissioning trust funds	8,071	7,248
Investments	1,165	1,184
Investments in affiliates	22	22
Investment in CENG	1,925	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	607	937
Unamortized energy contract assets	710	1,073
Pledged assets for Zion Station decommissioning	458	614
Deferred income taxes	—	58
Other	964	1,128
Total deferred debits and other assets	22,457	23,235
Total assets	$79,924	$78,561

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 341	$ —
Short-term notes payable—accounts receivable agreement	—	210
Long-term debt due within one year	1,424	975
Long-term debt due within one year of variable interest entities	85	72
Accounts payable	2,314	2,378
Accounts payable of variable interest entities	170	202
Payables to affiliates	116	112
Mark-to-market derivative liabilities	159	352
Unamortized energy contract liabilities	261	455
Accrued expenses	1,633	1,796
Deferred income taxes	40	58
Regulatory liabilities	327	368
Other	858	813
Total current liabilities	7,728	7,791
Long-term debt	17,325	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	298	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	12,905	11,551
Asset retirement obligations	5,194	5,074
Pension obligations	1,876	3,428
Non-pension postretirement benefit obligations	2,190	2,662
Spent nuclear fuel obligation	1,021	1,020
Regulatory liabilities	4,388	3,981
Mark-to-market derivative liabilities	300	281
Unamortized energy contract liabilities	266	528
Payable for Zion Station decommissioning	305	432
Other	2,540	1,650
Total deferred credits and other liabilities	30,985	30,607
Total liabilities	56,984	56,744
Commitments and contingencies		
Preferred securities of subsidiary	—	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 857 and 855 shares outstanding at December 31, 2013 and 2012, respectively)	16,741	16,632
Treasury stock, at cost (35 shares held at December 31, 2013 and 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,358	9,893
Accumulated other comprehensive loss, net	(2,040)	(2,767)
Total shareholders' equity	22,732	21,431
BGE preference stock not subject to mandatory redemption	193	193
Non-controlling interest	15	106
Total equity	22,940	21,730
Total liabilities and shareholders' equity	$79,924	$78,561

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2010	696,589	$ 9,006	$ (2,327)	$ 9,304	$ (2,423)	$ 3	$ —	$ 13,563
Net income	—	—	—	2,495	—	—	4	2,499
Long-term incentive plan activity	861	76	—	—	—	—	—	76
Employee stock purchase plan issuances	662	25	—	—	—	—	—	25
Common stock dividends	—	—	—	(1,744)	—	—	—	(1,744)
Preferred and preference stock dividends	—	—	—	—	—	—	(4)	(4)
Other comprehensive loss, net of income taxes of $(41)	—	—	—	—	(27)	—	—	(27)
Balance, December 31, 2011	698,112	$ 9,107	$ (2,327)	$ 10,055	$ (2,450)	$ 3	$ —	$ 14,388
Net income (loss)	—	—	—	1,160	—	(3)	14	1,171
Long-term incentive plan activity	2,432	126	—	—	—	—	—	126
Employee stock purchase plan issuances	857	26	—	—	—	—	—	26
Common stock dividends	—	—	—	(1,322)	—	—	—	(1,322)
Common stock issuance Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Non-controlling interest acquired	—	8	—	—	—	106	—	114
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive loss, net of income taxes of $(192)	—	—	—	—	(317)	—	—	(317)
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)	—	—	—	1,719	—	(10)	20	1,729
Long-term incentive plan activity	1,445	81	—	—	—	—	—	81
Employee stock purchase plan issuances	1,064	28	—	—	—	—	—	28
Common stock dividends	—	—	—	(1,254)	—	—	—	(1,254)
Consolidated VIE dividend to non-controlling interest	—	—	—	—	—	(63)	—	(63)
Deconsolidation of VIE	—	—	—	—	—	(18)	—	(18)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive income, net of income taxes of $(468)	—	—	—	—	727	—	—	727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$ 14,207	$ 12,735	$ 9,286
Operating revenues from affiliates	1,423	1,702	1,161
Total operating revenues	15,630	14,437	10,447
Operating expenses			
Purchased power and fuel	6,927	6,017	3,451
Purchased power and fuel from affiliates	1,270	1,044	138
Operating and maintenance	3,960	4,398	2,827
Operating and maintenance from affiliates	574	630	321
Depreciation and amortization	856	768	570
Taxes other than income	389	369	264
Total operating expenses	13,976	13,226	7,571
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	1,664	1,120	2,875
Other income and (deductions)			
Interest expense	(298)	(226)	(170)
Interest expense to affiliates, net	(59)	(75)	—
Other, net	368	239	122
Total other income and (deductions)	11	(62)	(48)
Income before income taxes	1,675	1,058	2,827
Income taxes	615	500	1,056
Net income	1,060	558	1,771
Net loss attributable to non-controlling interests	(10)	(4)	—
Net income attributable to membership interest	1,070	562	1,771
Comprehensive income (loss), net of income taxes			
Net income	1,060	558	1,771
Other comprehensive income (loss)			
Unrealized loss on cash flow hedges, net of income taxes of $(262), $(262) and $(64), respectively	(398)	(403)	(98)
Unrealized income on equity investments, net of income taxes of $72, $(1) and $0, respectively	107	1	—
Unrealized loss on foreign currency translation, net of income taxes of $0, $0 and $0, respectively	(10)	—	—
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	2	—	—
Other comprehensive loss	(299)	(402)	(98)
Comprehensive income	$ 761	$ 156	$ 1,673

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 1,060	$ 558	$ 1,771
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,559	2,966	1,539
Loss on sale of three Maryland generating stations	—	272	—
Deferred income taxes and amortization of investment tax credits	315	408	551
Net fair value changes related to derivatives	(448)	(611)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	414	537	421
Changes in assets and liabilities:			
Accounts receivable	109	248	(122)
Receivables from and payables to affiliates, net	2	39	208
Inventories	(88)	31	(47)
Accounts payable, accrued expenses and other current liabilities	(109)	(499)	34
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral (posted) received, net	162	95	(410)
Income taxes	402	114	193
Pension and non-pension postretirement benefit contributions	(149)	(178)	(1,070)
Other assets and liabilities	(136)	(128)	(57)
Net cash flows provided by operating activities	3,887	3,581	3,313
Cash flows from investing activities			
Capital expenditures	(2,752)	(3,554)	(2,491)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation	—	708	—
Proceeds from sale of long-lived assets	32	371	—
Acquisitions of long lived assets	—	(21)	(387)
Change in restricted cash	(64)	4	—
Changes in Exelon intercompany money pool	(44)	—	—
Distribution from CENG	115	—	—
Other investing activities	30	81	(6)
Net cash flows used in investing activities	(2,916)	(2,629)	(3,077)
Cash flows from financing activities			
Change in short-term debt	13	(52)	—
Issuance of long-term debt	854	1,076	—
Retirement of long-term debt	(570)	(145)	(2)
Distribution to member	(625)	(1,626)	(172)
Contribution from member	26	48	30
Other financing activities	(82)	(78)	(52)
Net cash flows used in financing activities	(384)	(777)	(196)
Increase in cash and cash equivalents	587	175	40
Cash and cash equivalents at beginning of period	671	496	456
Cash and cash equivalents at end of period	$ 1,258	$ 671	$ 496

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,196	$ 596
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and cash equivalents	19	—
Restricted cash and cash equivalents of variable interest entities	52	16
Accounts receivable, net		
Customer	1,429	1,482
Other	353	472
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Mark-to-market derivative assets with affiliate	—	226
Receivables from affiliates	108	141
Receivable from Exelon intercompany money pool	44	—
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	164	130
Materials and supplies	671	626
Deferred income taxes	475	—
Other	505	331
Total current assets	6,439	6,211
Property, plant and equipment, net	20,111	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	8,071	7,248
Investments	400	420
Investment in CENG	1,925	1,849
Mark-to-market derivative assets	600	924
Prepaid pension asset	1,873	1,975
Pledged assets for Zion Station decommissioning	458	614
Unamortized energy contract assets	710	1,073
Other	645	836
Total deferred debits and other assets	14,682	14,939
Total assets	$41,232	$40,681

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 22	$ —
Long-term debt due within one year	556	24
Long-term debt due within one year of variable interest entities	5	4
Accounts payable	1,152	1,326
Accounts payable of variable interest entities	170	202
Accrued expenses	976	1,116
Payables to affiliates	181	213
Deferred income taxes	25	128
Mark-to-market derivative liabilities	142	334
Unamortized energy contract liabilities	249	378
Other	389	372
Total current liabilities	3,867	4,097
Long-term debt	5,559	5,245
Long-term debt to affiliate	1,523	2,007
Long-term debt of variable interest entities	86	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,295	5,398
Asset retirement obligations	5,047	4,938
Non-pension postretirement benefit obligations	850	755
Spent nuclear fuel obligation	1,021	1,020
Payables to affiliates	2,740	2,397
Mark-to-market derivative liabilities	120	232
Unamortized energy contract liabilities	266	516
Payable for Zion Station decommissioning	305	432
Other	811	776
Total deferred credits and other liabilities	17,455	16,464
Total liabilities	28,490	28,016
Commitments and contingencies		
Equity		
Member’s equity		
Membership interest	8,898	8,876
Undistributed earnings	3,613	3,168
Accumulated other comprehensive income, net	214	513
Total member’s equity	12,725	12,557
Non-controlling interest	17	108
Total equity	12,742	12,665
Total liabilities and equity	$41,232	$40,681

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Member's Equity

(In millions)	Member's Equity: Membership Interest	Member's Equity: Undistributed Earnings	Member's Equity: Accumulated Other Comprehensive Income	Non-controlling Interest	Total Equity
Balance, December 31, 2010	$ 3,526	$ 2,633	$ 1,013	$ 5	$ 7,177
Net income	—	1,771	—	—	1,771
Distribution to member	—	(172)	—	—	(172)
Allocation of tax benefit from member	30	—	—	—	30
Other comprehensive loss, net of income taxes of $(64)	—	—	(98)	—	(98)
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income	—	562	—	(4)	558
Distribution to member	—	(1,626)	—	—	(1,626)
Allocation of tax benefit from member	48	—	—	—	48
Acquisition of Constellation	5,264	—	—	—	5,264
Non-controlling interest acquired	8	—	—	107	115
Other comprehensive loss, net of income taxes of $(261)	—	—	(402)	—	(402)
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$ 12,665
Net income	—	1,070	—	(10)	1,060
Distribution to member	—	(625)	—	—	(625)
Allocation of tax benefit from member	26	—	—	—	26
Consolidated VIE dividend to non-controlling interest	—	—		(63)	(63)
Deconsolidation of VIE	(1)	—	—	(18)	(19)
Non-controlling interest acquired	(3)	—	—	—	(3)
Other comprehensive loss, net of income taxes of $(190)	—	—	(299)	—	(299)
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$4,461	$5,441	$6,054
Operating revenues from affiliates	3	2	2
Total operating revenues	4,464	5,443	6,056
Operating expenses			
Purchased power	662	1,518	2,382
Purchased power from affiliate	512	789	653
Operating and maintenance	1,211	1,182	1,031
Operating and maintenance from affiliate	157	163	158
Depreciation and amortization	669	610	554
Taxes other than income	299	295	296
Total operating expenses	3,510	4,557	5,074
Operating income	954	886	982
Other income and (deductions)			
Interest expense	(566)	(294)	(330)
Interest expense to affiliates, net	(13)	(13)	(15)
Other, net	26	39	29
Total other income and (deductions)	(553)	(268)	(316)
Income before income taxes	401	618	666
Income taxes	152	239	250
Net income	249	379	416
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	—	1	—
Other comprehensive income	—	1	—
Comprehensive income	$ 249	$ 380	$ 416

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended 2013	2012	2011
Cash flows from operating activities			
Net income	$ 249	$ 379	$ 416
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	669	610	554
Deferred income taxes and amortization of investment tax credits	(57)	270	700
Other non-cash operating activities	28	252	184
Changes in assets and liabilities:			
Accounts receivable	(12)	24	5
Receivables from and payables to affiliates, net	(12)	(18)	(287)
Inventories	(18)	(11)	(9)
Accounts payable, accrued expenses and other current liabilities	74	59	(84)
Counterparty collateral received, net	53	40	66
Income taxes	178	9	223
Pension and non-pension postretirement benefit contributions	(122)	(138)	(977)
Other assets and liabilities	188	(142)	45
Net cash flows provided by operating activities	1,218	1,334	836
Cash flows from investing activities			
Capital expenditures	(1,433)	(1,246)	(1,028)
Proceeds from sales of investments	7	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(2)	—	—
Other investing activities	45	19	19
Net cash flows used in investing activities	(1,387)	(1,212)	(1,007)
Cash flows from financing activities			
Changes in short-term debt	184	—	—
Issuance of long-term debt	350	350	1,199
Retirement of long-term debt	(252)	(450)	(537)
Dividends paid on common stock	(220)	(105)	(300)
Other financing activities	(1)	(7)	(7)
Net cash flows provided by (used in) financing activities	61	(212)	355
Increase (decrease) in cash and cash equivalents	(108)	(90)	184
Cash and cash equivalents at beginning of period	144	234	50
Cash and cash equivalents at end of period	$ 36	$ 144	$ 234

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 36	$ 144
Restricted cash	2	—
Accounts receivable, net		
Customer	451	539
Other	584	452
Inventories, net	109	91
Deferred income taxes	—	83
Counterparty collateral deposited	—	53
Regulatory assets	329	388
Other	29	25
Total current assets	1,540	1,775
Property, plant and equipment, net	14,666	13,826
Deferred debits and other assets		
Regulatory assets	933	666
Investments	5	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,469	2,039
Prepaid pension asset	1,583	1,661
Other	291	299
Total deferred debits and other assets	7,912	7,304
Total assets	$ 24,118	$ 22,905

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 184	$ —
Long-term debt due within one year	617	252
Accounts payable	449	379
Accrued expenses	307	295
Payables to affiliates	83	97
Customer deposits	133	136
Regulatory liabilities	170	170
Mark-to-market derivative liability	17	18
Mark-to-market derivative liability with affiliate	—	226
Deferred income taxes	16	—
Other	72	82
Total current liabilities	2,048	1,655
Long-term debt	5,058	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,116	4,272
Asset retirement obligations	99	99
Non-pension postretirement benefits obligations	381	273
Regulatory liabilities	3,512	3,229
Mark-to-market derivative liability	176	49
Other	994	484
Total deferred credits and other liabilities	9,278	8,406
Total liabilities	16,590	15,582
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,190	5,014
Retained earnings	750	721
Total shareholders' equity	7,528	7,323
Total liabilities and shareholders' equity	$24,118	$22,905

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 2010	$ 1,588	$4,992	$ (1,639)	$ 1,970	$ (1)	$ 6,910
Net income	—	—	416	—	—	416
Common stock dividends	—	—	—	(300)	—	(300)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(416)	416	—	—
Balance, December 31, 2011	$ 1,588	$ 5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037
Net income	—	—	379	—	—	379
Common stock dividends	—	—	—	(105)	—	(105)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(379)	379	—	—
Other comprehensive income, net of income taxes of $0	—	—	—	—	1	1
Balance, December 31, 2012	$ 1,588	$ 5,014	$ (1,639)	$ 2,360	$ —	$ 7,323
Net income	—	—	249	—	—	249
Common stock dividends	—	—	—	(220)	—	(220)
Parent tax matter indemnification	—	176	—	—	—	176
Appropriation of retained earnings for future dividends	—	—	(249)	249	—	—
Balance, December 31, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$ —	$ 7,528

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$3,099	$3,183	$3,715
Operating revenues from affiliates	1	3	5
Total operating revenues	3,100	3,186	3,720
Operating expenses			
Purchased power and fuel	908	842	1,369
Purchased power from affiliate	392	533	495
Operating and maintenance	647	698	698
Operating and maintenance from affiliates	101	111	96
Depreciation and amortization	228	217	202
Taxes other than income	158	162	205
Total operating expenses	2,434	2,563	3,065
Operating income	666	623	655
Other income and (deductions)			
Interest expense	(103)	(111)	(122)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	6	8	14
Total other income and (deductions)	(109)	(115)	(120)
Income before income taxes	557	508	535
Income taxes	162	127	146
Net income	395	381	389
Preferred security dividends and redemption	7	4	4
Net income attributable to common shareholder	388	377	385
Comprehensive income, net of income taxes			
Net income	395	381	389
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	—	1	—
Other comprehensive income	—	1	—
Comprehensive income	$ 395	$ 382	$ 389

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 395	$ 381	$ 389
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	228	217	202
Deferred income taxes and amortization of investment tax credits	20	37	253
Other non-cash operating activities	108	125	100
Changes in assets and liabilities:			
Accounts receivable	(79)	(14)	225
Receivables from and payables to affiliates, net	(18)	13	(217)
Inventories	2	21	—
Accounts payable, accrued expenses and other current liabilities	41	(47)	34
Income taxes	87	174	(45)
Pension and non-pension postretirement benefit contributions	(31)	(45)	(137)
Other assets and liabilities	(6)	16	14
Net cash flows provided by operating activities	747	878	818
Cash flows from investing activities			
Capital expenditures	(537)	(422)	(481)
Changes in intercompany money pool	—	82	(82)
Change in restricted cash	(2)	2	(2)
Other investing activities	8	10	8
Net cash flows used in investing activities	(531)	(328)	(557)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	—
Issuance of long-term debt	550	350	—
Retirement of long-term debt	(300)	(375)	(250)
Contributions from parent	27	9	18
Dividends paid on common stock	(332)	(343)	(348)
Dividends paid on preferred securities	(1)	(4)	(4)
Redemption of preferred securities	(93)	—	—
Other financing activities	(2)	(4)	(5)
Net cash flows used in financing activities	(361)	(382)	(589)
Increase (decrease) in cash and cash equivalents	(145)	168	(328)
Cash and cash equivalents at beginning of period	362	194	522
Cash and cash equivalents at end of period	$ 217	$ 362	$ 194

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 217	$ 362
Restricted cash and cash equivalents	2	—
Accounts receivable, net ($0 and $289 gross accounts receivable pledged as collateral as of December 31, 2013 and 2012, respectively)		
Customer	360	364
Other	107	161
Inventories, net		
Fossil fuel	60	65
Materials and supplies	21	19
Deferred income taxes	83	40
Prepaid utility taxes	3	21
Regulatory assets	17	32
Other	36	30
Total current assets	906	1,094
Property, plant and equipment, net	6,384	6,078
Deferred debits and other assets		
Regulatory assets	1,448	1,378
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	447	360
Prepaid pension asset	363	373
Other	38	40
Total deferred debits and other assets	2,327	2,181
Total assets	$9,617	$9,353

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable—accounts receivable agreement	$ —	$ 210
Long-term debt due within one year	250	300
Accounts payable	285	244
Accrued expenses	106	82
Payables to affiliates	58	76
Customer deposits	49	51
Regulatory liabilities	106	169
Other	37	26
Total current liabilities	891	1,158
Long-term debt	1,947	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,487	2,331
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	286	284
Regulatory liabilities	629	538
Other	99	113
Total deferred credits and other liabilities	3,530	3,295
Total liabilities	6,552	6,284
Commitments and contingencies		
Preferred securities	—	87
Shareholders' equity		
Common stock	2,415	2,388
Retained earnings	649	593
Accumulated other comprehensive income, net	1	1
Total shareholders' equity	3,065	2,982
Total liabilities and shareholders' equity	$9,617	$9,353

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Stockholders' Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2010	$ 2,361	$ 522	$ —	$ 2,883
Net income	—	389	—	389
Common stock dividends	—	(348)	—	(348)
Preferred security dividends	—	(4)	—	(4)
Allocation of tax benefit from parent	18	—	—	18
Balance, December 31, 2011	$ 2,379	$ 559	$ —	$ 2,938
Net income	—	381	—	381
Common stock dividends	—	(343)	—	(343)
Preferred security dividends	—	(4)	—	(4)
Allocation of tax benefit from parent	9	—	—	9
Other comprehensive income, net of income taxes of $0	—	—	1	1
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income	—	395	—	395
Common stock dividends	—	(332)	—	(332)
Preferred security dividends	—	(1)	—	(1)
Redemption of preferred securities	—	(6)	—	(6)
Allocation of tax benefit from parent	27	—	—	27
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$3,052	$2,725	$3,060
Operating revenues from affiliates	13	10	8
Total operating revenues	3,065	2,735	3,068
Operating expenses			
Purchased power and fuel	969	973	1,245
Purchased power from affiliate	452	396	348
Operating and maintenance	551	622	530
Operating and maintenance from affiliates	83	106	150
Depreciation and amortization	348	298	274
Taxes other than income	213	208	207
Total operating expenses	2,616	2,603	2,754
Operating income	449	132	314
Other income and (deductions)			
Interest expense	(106)	(128)	(113)
Interest expense to affiliates, net	(16)	(16)	(16)
Other, net	17	23	26
Total other income and (deductions)	(105)	(121)	(103)
Income before income taxes	344	11	211
Income taxes	134	7	75
Net income	210	4	136
Preference stock dividends	13	13	13
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 123
Comprehensive income	$ 210	$ 4	$ 136

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 210	$ 4	$ 136
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	348	298	274
Deferred income taxes and amortization of investment tax credits	125	104	145
Other non-cash operating activities	153	193	129
Changes in assets and liabilities:			
Accounts receivable	(127)	(45)	60
Receivables from and payables to affiliates, net	(14)	26	(44)
Inventories	1	25	(10)
Accounts payable, accrued expenses and other current liabilities	(14)	(33)	(21)
Income taxes	(33)	14	35
Pension and non-pension postretirement benefit contributions	(24)	(16)	(67)
Other assets and liabilities	(64)	(85)	(161)
Net cash flows provided by operating activities	561	485	476
Cash flows from investing activities			
Capital expenditures	(587)	(582)	(592)
Change in restricted cash	2	—	—
Other investing activities	14	9	—
Net cash flows used in investing activities	(571)	(573)	(592)
Cash flows from financing activities			
Changes in short-term debt	135	—	—
Issuance of long-term debt	300	250	300
Retirement of long-term debt	(467)	(173)	(82)
Dividends paid on common stock	—	—	(85)
Dividends paid on preference stock	(13)	(13)	(13)
Contributions from parent	—	66	—
Other financing activities	(3)	(2)	(5)
Net cash flows (used in) provided by financing activities	(48)	128	115
Increase (decrease) in cash and cash equivalents	(58)	40	(1)
Cash and cash equivalents at beginning of period	89	49	50
Cash and cash equivalents at end of period	$ 31	$ 89	$ 49

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 31	$ 89
Restricted cash and cash equivalents of variable interest entity	28	30
Accounts receivable, net		
Customer	480	409
Other	114	111
Income taxes receivable	30	3
Inventories, net		
Gas held in storage	53	51
Materials and supplies	28	31
Deferred income taxes	2	1
Prepaid utility taxes	57	57
Regulatory assets	181	190
Other	7	8
Total current assets	1,011	980
Property, plant and equipment, net	5,864	5,498
Deferred debits and other assets		
Regulatory assets	524	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	423	467
Other	26	26
Total deferred debits and other assets	986	1,028
Total assets	$7,861	$7,506

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 135	$ —
Long-term debt due within one year	—	400
Long-term debt of variable interest entity due within one year	70	67
Accounts payable	270	235
Accrued expenses	111	102
Deferred income taxes	27	—
Payables to affiliates	55	69
Customer deposits	76	71
Regulatory liabilities	48	29
Other	35	7
Total current liabilities	827	980
Long-term debt	1,746	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	195	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,773	1,658
Asset retirement obligations	19	8
Non-pension postretirement benefits obligations	217	229
Regulatory liabilities	204	214
Other	67	90
Total deferred credits and other liabilities	2,280	2,199
Total liabilities	5,306	5,148
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	1,005	808
Total shareholders' equity	2,365	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,555	2,358
Total liabilities and shareholders' equity	$7,861	$7,506

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statement of Changes in Shareholders' Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2010	$ 1,294	$ 779	$ 2,073	$ 190	$2,263
Net income	—	136	136	—	136
Common stock dividends	—	(85)	(85)	—	(85)
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2011	$ 1,294	$ 817	$ 2,111	$ 190	$ 2,301
Net income	—	4	4	—	4
Preference stock dividends	—	(13)	(13)	—	(13)
Contribution from parent	66	—	66	—	66
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$2,358
Net income	—	210	210	—	210
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$ 2,555

See the Combined Notes to Consolidated Financial Statements

1. Significant Accounting Policies (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon's principal subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger ("Merger Agreement"). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4—Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation*: Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

- *ComEd*: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO*: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE*: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as indicated parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE and BGE continued to be subject to reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the twelve months ended December 31, 2013, 2012 and 2011 and the financial position as of December 31, 2013 and December 31, 2012. However, for Exelon's consolidated financial reporting, Exelon is reporting BGE activity from the acquisition date of March 12, 2012 through December 31, 2013.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preference stock. Exelon owned none of PECO's preferred securities, which PECO redeemed in 2013. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2013 and December 31, 2012, as equity, PECO's preferred securities as preferred securities of subsidiary through their redemption in 2013, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain Exelon Wind projects, of which Generation holds a majority interest ranging from 94% to 99% for certain periods of time, and the remaining interests are included in non-controlling interest on Exelon's and Generation's Consolidated Balance Sheets. See Note 2 for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the non-controlling members for certain of these projects.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC, of which ComEd owns 75% and an additional 12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2013 and December 31, 2012, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity, it applies proportional consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting to certain investments and joint ventures, including the 50.01% interest in CENG, and certain financing trusts of ComEd, PECO, and BGE. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon's percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

For the year ended December 31, 2013, BGE recorded a $2 million (pre-tax) correcting adjustment to decrease amortization expense related to regulatory assets that were originally recorded during 2012, an adjustment to decrease income tax expense by $4 million related to the recognition and measurement of regulatory assets that should have been recorded in periods prior to 2013, and a $4 million (pre-tax) correcting adjustment to decrease operating and maintenance expense for an overstatement of BGE's life insurance obligation related to post-employment benefits in prior years. For the year ended December 31, 2012, BGE recorded a $2 million (pre-tax) correcting adjustment to reduce electric distribution revenue related to decoupling of 2011 electric distribution revenue, a $3 million (pre-tax) correcting adjustment to increase electric operations and maintenance expense related to capitalization of electric transmission costs, and a $5 million (pre-tax) correcting adjustment to interest expense to reflect the impacts of amendments of tax positions previously taken on prior-year consolidated income tax returns. In addition, ComEd identified a disclosure adjustment within the renewable energy credits and alternative energy credits section of the 2012 Form 10-K Note 8—Intangible Assets which has been revised in Note 10 of this year's report. Exelon, ComEd and BGE have concluded these correcting adjustments are not material to its results of operations, cash flows, or financial positions for the years ended December 31, 2013, and December 31, 2012, or any prior period.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

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

Reclassifications (Exelon, ComEd, and BGE)

Certain prior year amounts in Exelon's and BGE's Consolidated Statements of Operations and Cash Flows, and Exelon's, ComEd's, and BGE's Consolidated Balance Sheets have been reclassified between line items for comparative purposes and correction of prior period classification errors identified in 2013. The reclassifications did not affect any of the Registrants' net income or cash flows from operating activities.

In 2013, Exelon and BGE corrected the presentation of interest expense related to BGE's financing trust of $12 million and $16 million, respectively, to be presented as Interest expense to affiliates, net on their Statements of Operations and Comprehensive Income for the year ended December 31, 2012. BGE also reclassified the related Accrued expenses of $4 million to Payables to affiliates on its December 31, 2012 Balance Sheet. Similar adjustments are also reflected in Note 22 – Related Party Transactions. Exelon and Generation also corrected amounts disclosed within Note 22 – Related Party Transactions to increase Purchased power and fuel from affiliates by $114 million and to increase Payables to affiliates by $20 million. In 2013, Generation corrected the presentation of interest expense related to certain debt of $75 million to be presented as Interest expense to affiliates, net on its Statement of Operations and Comprehensive Income for the year ended December 31, 2012 and within Note 22 – Related Party Transactions.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation, which requires ComEd, PECO and BGE to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Exelon, ComEd, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, respectively, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd, PECO and BGE continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's, PECO's or BGE's business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

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

Revenues (Exelon, Generation, ComEd, PECO and BGE)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Note 3—Regulatory Matters and Note 6—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As of the merger date, Exelon and Generation have currently elected to de-designate all of their commodity cash flow hedge positions. As ComEd receives full cost recovery for energy procurement and related costs from retail customers, ComEd records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 12—Derivative Financial Instruments for further information.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

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

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 14—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 23—Supplemental Financial Information for Generation's, ComEd's, PECO's and BGE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and investments represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2013 and 2012, Exelon Corporate's restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, Exelon Corporate has funds restricted for merger commitments. In addition, Exelon Corporate's investments include its direct financing lease investments. As of December 31, 2013, Generation's restricted cash and investments primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2012, Generation's restricted cash primarily included cash at Antelope Valley required for debt service and construction. As of December 31, 2013 and 2012, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's REC procurement contracts. As of December 31, 2013, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2013 and 2012, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2013 and 2012, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2013, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has presented separately on its Consolidated Balance Sheets, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon's consolidated VIEs for which creditors do not have recourse to Exelon's general credit.
- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity.

See Note 2—Variable Interest Entities for additional information.

Inventories (Exelon, Generation, ComEd, PECO and BGE)

Inventory is recorded at the lower of weighted average cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds, certain Generation Rabbi trust investments and BGE's Rabbi trust investments are classified as trading securities and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former ComEd and former PECO nuclear generating units (Regulatory Agreement Units) are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former AmerGen nuclear generating units, the Zion generating station and portions of the Peach Bottom nuclear generating units not subject to a regulatory agreement (Non-Regulatory Agreement Units) are included in earnings at Exelon and Generation. Realized and unrealized gains and losses, net of tax, on certain Generation Rabbi trust investments and BGE's Rabbi trust investments are included in earnings at Exelon, Generation and BGE. Unrealized gains and losses, net of tax, for Generation's, ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 15—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 23—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Property, plant and equipment is recorded at original cost. Original cost includes labor, materials and construction overhead. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred. For constructed assets, Exelon capitalizes construction-related direct labor and material costs. ComEd, PECO and BGE also capitalized indirect construction costs including labor and related costs of departments associated with supporting construction activities.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to operating and maintenance expense as incurred.

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's and BGE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. ComEd's and BGE's actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

Generation's oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

See Note 7—Property, Plant and Equipment, Note 9—Jointly Owned Electric Utility Plant and Note 23—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. The estimated disposal cost of SNF is established per the Standard Waste Contract with the DOE and is expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. On-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 22—Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. At December 31, 2013 and 2012, there were no material capitalized development costs for projects not yet under construction included in Property, plant and equipment, net on Exelon's and Generation's Consolidated Balance Sheets. Approximately $10 million, $4 million and $2 million of costs were expensed by Exelon and Generation for the years ended December 31, 2013, 2012, and 2011, respectively. These costs primarily related to the possible development of new renewable energy projects.

(Dollars in millions, except per share data unless otherwise noted)

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$ 479	$ 129	$ 101	$ 71	$ 155
December 31, 2012	499	143	105	63	157

Amortization of capitalized software costs	Exelon (a)	Generation (a)	ComEd	PECO	BGE (a)
2013	$ 198	$67	$52	$ 33	$36
2012	208	81	56	30	32
2011	122	41	50	25	25

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012 and 2011.

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd’s and BGE’s depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation’s operating nuclear generating stations except for Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations.

See Note 7—Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost would have originally been recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income. With exception of income tax-related regulatory assets, when the recovery period is more than one year, the amortization is recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income. For income tax related regulatory assets, amortization is generally recorded to Income tax expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3—Regulatory Matters and Note 23—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's, PECO's and BGE's regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations or, in the case of the majority of ComEd's, PECO's, and BGE's accretion, through an increase to regulatory assets. See Note 15—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

(Dollars in millions, except per share data unless otherwise noted)

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

		Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(a)]
2013	Total incurred interest [(b)]	$1,423	$ 411	$ 584	$ 117	$ 129
	Capitalized interest	54	54	—	—	—
	Credits to AFUDC debt and equity	35	—	16	6	13
2012	Total incurred interest [(b)]	$ 1,003	$ 368	$ 310	$ 125	$ 149
	Capitalized interest	67	67	—	—	—
	Credits to AFUDC debt and equity	25	—	9	6	15
2011	Total incurred interest [(b)]	$ 783	$ 219	$ 349	$138	$ 136
	Capitalized interest	49	49	—	—	—
	Credits to AFUDC debt and equity	25	—	12	13	22

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012, 2011 and 2010.
(b) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd, PECO and BGE)

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

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 22—Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. The Registrants determine if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Cash flows from Generation plant assets are generally evaluated at a regional portfolio level along with cash flows generated from Generation's supply and risk management activities, including cash flows from contracts that are recorded as intangible contract assets and liabilities on the balance sheet. In certain cases generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables).

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

Conditions that could have an adverse impact on the expected future cash flows and the fair value of the long-lived assets and asset groups include, among other factors, a deteriorating business climate, including energy prices and market conditions, revisions to regulatory laws, or plans to dispose of a long-lived asset significantly before the end of its useful life. See Note 8—Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10—Intangible Assets for additional information regarding Exelon’s and ComEd’s goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is not temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other than temporary decline in value.

Direct Financing Lease Investments. Direct financing lease investments represent the estimated residual values of leased coal-fired plants in Georgia and Texas. Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. See Note 8—Impairment of Long-Lived Assets for additional information.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon’s Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statement of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For commodity derivative contracts, effective with the date of the merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivatives executed to hedge economic risk for commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 12—Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective March 12, 2012, Exelon became the sponsor of all of Constellation's defined benefit pension and other postretirement benefit plans and defined contribution savings plans.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 16—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, including Generation's 50.01% interest in CENG, in equity in earnings (losses) of unconsolidated affiliates. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment. See Note 5—Investment in CENG and Note 25—Related Party Transactions for additional discussion of Exelon's and Generation's investment in CENG.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other than temporary decline in value.

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

Exelon has identified the following new accounting pronouncements that have been recently adopted or issued that may affect the Registrants.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance was effective for the Registrants for periods beginning after December 15, 2012 and was required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions. See Note 21—Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011 (and amended in January 2013), the FASB issued authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. The guidance was effective for the Registrants for periods beginning on or after January 1, 2013 and was required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions. See Note 12—Derivative Financial Instruments for the new disclosures.

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes

In July 2013, the FASB issued authoritative guidance permitting entities to designate the Fed Funds Effective Swap Rate as a U.S. benchmark interest rate for hedge accounting purposes. Prior to the issuance of this guidance, only interest rates on direct treasury obligations of the U.S. government and the LIBOR swap rate were considered benchmark interest rates in the U.S. This guidance was effective immediately and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. Currently, the Registrants do not use the Fed Funds Effective Swap Rate as a benchmark interest rate, but may in the future.

The following recently issued accounting standard is not yet required to be reflected in the combined financial statements of the Registrants.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. Currently, the Registrants present their unrecognized tax benefits as liabilities on a gross basis unless an unrecognized tax benefit is directly associated with a tax position taken in a tax year that results in the recognition of a net operating loss or other tax carryforward for that year. This guidance is effective for the Registrants for periods beginning after December 15, 2013 and is required to be applied prospectively, with retroactive application permitted. The Registrants will not retroactively adopt this guidance. This guidance is currently not expected to have an impact on the Registrants upon adoption with the exception of Exelon and Generation in which approximately $11 million of unrecognized tax benefits will be offset against current deferred income assets. The adoption of this standard will not impact the Registrants' results of operations.

2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity's economic performance.

At December 31, 2013 and 2012, the Exelon, Generation, and BGE consolidated four and five VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary. As of December 31, 2013, the Registrants had one VIE for which the Registrants were the primary beneficiary, however, the VIE is immaterial and was not included in the consolidated financial statements or in the consolidated VIE table below. As of December 31, 2013 and 2012, the Registrants had significant interests in eight and nine other VIEs for which the Registrants do not have the power to direct the entities' activities, respectively, and accordingly, were not the primary beneficiary.

(Dollars in millions, except per share data unless otherwise noted)

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2013 and 2012 are as follows:

	December 31, 2013			December 31, 2012		
	Exelon [(a)]	Generation	BGE	Exelon [(a)(b)]	Generation [(b)]	BGE
Current assets	$ 484	$ 446	$ 28	$ 550	$ 519	$ 30
Noncurrent assets	1,905	1,884	3	1,719	1,680	—
Total assets	$2,389	$ 2,330	$ 31	$ 2,269	$ 2,199	$ 30
Current liabilities	$ 566	$ 481	$ 74	$ 684	$ 612	$ 71
Noncurrent liabilities	774	562	195	775	470	265
Total liabilities	$ 1,340	$ 1,043	$269	$ 1,459	$ 1,082	$336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $146 million and total liabilities of $42 million as of December 31, 2012 related to a retail supply company that is not a consolidated VIE as of December 31, 2013. See additional information below.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the preceding table can only be settled using VIE resources.

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2013, 2012, and 2011, BGE remitted $83 million, $85 million, and $92 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2013. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- The third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2013 Exelon provided a $75 million parental guarantee to the third-party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon’s or Generation’s general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Constellation formed a group of solar project limited liability companies to build, own, and operate solar power facilities, which are now part of Generation. Additionally, on September 30, 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 230-MW solar PV project under construction in northern Los Angeles County, California. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides capital funding to these solar VIE entities for ongoing construction of the solar power facilities. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $536 million, as of December 31, 2013, for which the creditors have no recourse to Generation, however there is limited recourse to Generation with respect to remaining equity contributions necessary to complete the Antelope Valley project. For additional information on these project-specific financing arrangements refer to Note 13—Debt and Credit Agreements.

Retail Power Supply Entity. In August 2013, Generation executed an agreement to terminate its energy supply contract with a retail power supply company that was previously a consolidated VIE. Generation did not have an ownership interest in the entity, but was the primary beneficiary through the energy supply contract. As a result of the termination, Generation no longer has a variable interest in the retail power supply company and ceased consolidation of the entity during the third quarter of 2013. Upon deconsolidation, there was no gain or loss recognized. The assets, liabilities, and non-controlling interest were removed from Exelon’s and Generation’s balance sheet and the change in non-controlling interest is also reflected on the Statement of Changes in Shareholders’ Equity and the Statement of Changes in Member’s Equity for Exelon and Generation, respectively.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired on December 9, 2010 when Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have non-controlling interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind power facilities. While Generation owns 100% of the majority of the wind project entities, 10 of the projects have non-controlling equity interests held by third parties, that currently range between 1% and 6%. Of these 10 projects, Generation's current economic interests in nine of the projects are significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the non-controlling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the non-controlling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the non-controlling interests state that Generation is to provide financial support to the projects in proportion to its current economic interests in the projects that currently range between 94% and 99%. However, no additional support to these projects beyond what was contractually required has been provided during 2013. As of December 31, 2013, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2013 and 2012, ComEd and PECO did not have any consolidated VIEs.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include three transaction types: (1) equity investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in Investments in affiliates. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2013 and 2012, Exelon and Generation had significant unconsolidated variable interests in eight and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity investments and certain commercial agreements. The change in the number of unconsolidated variable interests is driven by the completion of certain obligations which cause the entities to no longer be unconsolidated variable interests offset by the addition of an equity investment in a residential solar provider. The following tables present summary information about the significant unconsolidated VIE entities:

December 31, 2013	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 128	$ 332	$460
Total liabilities [a]	17	123	140
Registrants' ownership interest [a]	—	86	86
Other ownership interests [a]	111	123	234
Registrants' maximum exposure to loss:			
Carrying amount of equity investments	7	67	74
Contract intangible asset	9	—	9
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [b]	44	—	44

(Dollars in millions, except per share data unless otherwise noted)

December 31, 2012	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [(a)]	$ 386	$ 354	$740
Total liabilities [(a)]	219	114	333
Registrants' ownership interest [(a)]	—	97	97
Other ownership interests [(a)]	167	143	310
Registrants' maximum exposure to loss:			
Letters of credit	5	—	5
Carrying amount of equity investments	—	77	77
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [(b)]	50	—	50

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.
(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $458 million and $614 million as of December 31, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $414 million and $564 million as of December 31, 2013 and December 31, 2012, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 15—Asset Retirement Obligations for further discussion.

For each unconsolidated VIE, Exelon and Generation assess the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. In March 2005, Constellation, to which Generation is now a successor, closed a transaction in which Generation assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, Generation sold power to the VIEs which, in turn, sold that power to an electric distribution utility through 2013. In connection with this transaction, a third-party acquired the equity of the VIEs and Generation loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to Generation in lieu of repaying the loan. In this event, Generation would have the right to seek recovery of its losses from the electric distribution utility. As a result, Generation has concluded that consolidation was not required. During 2013, the third-party repaid their obligations of the loan with Generation which caused the entities to no longer be unconsolidated VIEs.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 15—Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning is complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon or Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Fuel Purchase Commitments. Generation's customer supply operations include the physical delivery and marketing of power obtained through its generating capacity, and long-, intermediate- and short-term contracts. Generation also has contracts to purchase fuel supplies for nuclear and fossil generation. These contracts and Generation's membership in NEIL are discussed in further detail in Note 22—Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that it either has no variable interest in an entity or, where Generation does have a variable interest in an entity, the variable interest is not significant and it is not the primary beneficiary; therefore, consolidation is not required.

For contracts where Generation has a variable interest, the level of variability being absorbed through the contracts is not considered significant because of the small proportion of the entities' activities encompassed by the contracts with Generation. Further, Generation has considered which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE and thus is considered the primary beneficiary and is required to consolidate the entity. The primary beneficiary must also have exposure to significant losses or the right to receive significant benefits from the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of the facilities. Facilities represent power plants, sources of uranium and fossil fuels, or plants used in the uranium conversion, enrichment and fabrication process. Generation does not have control over the operation and maintenance of the facilities considered VIEs, and it does not bear operational risk of the facilities. Furthermore, Generation has no debt or equity investments in the entities and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to have significant variable interests in these entities or be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

Investment in Energy Development Projects. Generation has several equity investments in energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are VIEs because Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities of the VIEs that most significantly impact the VIEs economic performance.

Residential Solar Provider. Generation has an equity investment in a residential solar provider. Generation has evaluated the significant agreements, ownership structure and risks of the entity, and determined that the entity is a VIE because it does not have sufficient equity at risk to fund its operations. Generation has determined that its equity investment in the entity is a variable interest. However, Generation has concluded that we are not the primary beneficiary because Generation does not have the power to direct the activities of the VIE that most significantly impact the entity's economic performance. Exelon or Generation do not have any contractual or other obligations to provide additional financial support and the residential solar provider's creditors do not have any recourse to Exelon's or Generation's general credit.

ComEd, PECO and BGE

ComEd's, PECO's, and BGE's retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies for additional information on these contracts. ComEd, PECO and BGE have evaluated these types of contracts and have historically determined that either there is no significant variable interest in the entity, or where either ComEd, PECO or BGE does have a significant variable interest in a VIE, ComEd, PECO or BGE would not be the primary beneficiary and, therefore, consolidation would not be required.

For contracts where ComEd, PECO or BGE is considered to have a significant variable interest, consideration is given to which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of their production or procurement processes related to electricity, RECs, AECs or natural gas. ComEd, PECO and BGE do not have control over the operation and maintenance of the entities and they do not bear operational risk related to the associated activities. Generally, the carrying amounts of assets and liabilities in ComEd's, PECO's, and BGE's Consolidated Balance Sheets that relate to their involvement with VIEs as a result of commercial arrangements represent the amounts owed by the utilities for the purchases associated with the current billing cycles under the contracts. As of December 31, 2013, the total amount of accounts payable owed by the utilities under agreements with these VIEs was not material. In addition, variability from these contracts is mitigated by the fact that the utilities are able to recover costs incurred under purchase agreements through customer rates. Furthermore, ComEd, PECO and BGE do not have any debt or equity investments in these VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22—Commitments and Contingencies. Accordingly, none of ComEd, PECO or BGE considers itself to be the primary beneficiary of any VIEs as a result of commercial arrangements.

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II are not consolidated in Exelon's, ComEd's, PECO's or BGE's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 13—Debt and Credit Agreements for additional information.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

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

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of December 31, 2013, and December 31, 2012, ComEd had a net regulatory asset associated with the distribution formula rate of $463 million and $209 million, respectively.

Formula Rate Tariff

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June 2012. On May 29, 2012, the ICC issued an Order (May Order) in that proceeding. The May Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than the proposed reduction by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC's determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in a subsequent annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd's pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a decrease in revenue of approximately $100 million pre-tax to decrease the regulatory asset for 2011 and for the first three months of 2012 consistent with the terms of the May Order.

On June 22, 2012, the ICC granted an expedited rehearing on three of the issues decided in the May Order. On October 3, 2012, the ICC issued its final order (Rehearing Order) in that rehearing, adopting ComEd's position on the return on its pension asset, resulting in an increase in the annual revenue requirement. For the two other issues, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in the annual reconciliation and amending its prior order to provide a short-term debt rate to apply to the annual reconciliation. In the fourth quarter of 2012, ComEd recorded an increase in revenue of approximately $135 million pre-tax consistent with the terms of the Rehearing Order, of which $75 million pre-tax reflects the reinstatement of the return on pension asset for 2011 and $60 million pre-tax reflects the return on pension asset for 2012. New rates reflecting the impacts of the Rehearing Order went into effect in November 2012. ComEd has filed an appeal with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd's pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd's weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor's veto of that Bill. On June 5, 2013, the ICC approved ComEd's updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd's 2014 revenue by approximately $8 million. This change had no financial statement impact on ComEd in 2013. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

Annual Reconciliation

2012 Filing. On April 30, 2012, ComEd filed its annual distribution formula rate. On December 20, 2012, the ICC, issued its final order, which increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the May 2012 and Rehearing Orders. The $73 million reflected an increase of $80 million for the initial revenue requirement for 2012 and a decrease of $7 million for the annual reconciliation for 2011. The rate increase was set using an allowed return on capital of 7.54% (inclusive of an allowed return on common equity of 9.81%). The rates took effect in January 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated in August 2013, to request a total increase to the revenue requirement of $353 million of which approximately $42 million related to Senate Bill 9. On December 19, 2013, the ICC issued its final order which increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd also filed an appeal. ComEd cannot predict the results of any such appeals.

Expenditures and Capital Investment

As part of the enactment of EIMA legislation ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million, the first of which was made on December 31, 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which will not be recoverable through rates. These contributions began in 2012.

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period. ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011 when the rates set in the 2010 electric distribution rate case (2010 Rate Case) became effective. In subsequent ICC proceedings, the ICC issued an order requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

However, on September 27, 2013 the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

Advanced Metering Program Proceeding (Exelon and ComEd) ComEd's 2007 Rate Case filing included a system modernization rider, which permitted investments in AMI to study the costs and benefits and to develop the cost estimate of full system-wide implementation. In October 2009, the ICC approved a modified version of ComEd's system modernization rider proposed in the 2007 Rate Case, Rider AMP (Advanced Metering Program). ComEd collected approximately $24 million under Rider AMP through December 31, 2013. Several other parties, including the Illinois Attorney General, appealed the ICC's order on Rider AMP. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of other costs from recovery under Rider AMP to recovery through electric distribution rates. On March 19, 2012, the Court reversed the ICC's approval of Rider AMP, concluding that the ICC's October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012, which was denied in September 2012, and the matter was returned to the ICC to calculate a refund amount. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Appellate Court's order on March 19, 2012. As a result, ComEd recorded a regulatory liability of approximately $0.4 million at December 31, 2013, which represents the amounts collected from customers since March 19, 2012. ComEd cannot predict the ultimate outcome of the ICC proceeding and therefore, actual refunds may differ from the estimated accrual recorded at December 31, 2013.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). On May 24, 2011, the ICC issued an order in ComEd's 2010 Rate Case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. ComEd originally requested a $396 million increase, although it was subsequently reduced to $343 million to account for various adjustments. As expected, the ICC followed the Court's ruling on ComEd's 2007 Rate Case on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately

$40 million of previously expensed plant balances or new regulatory assets, which is reflected as a reduction in operating and maintenance expense and income tax expense in 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order was appealed to the Court by several parties on a number of issues. On May 16, 2013, the Court dismissed as moot the appeals of the ICC's order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff.

Utility Consolidated Billing and Purchase of Receivables (Exelon and ComEd). Since the first quarter of 2011, ComEd has been required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bill to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of December 31, 2013, the balance of purchased accounts receivable was $105 million. Under the applicable tariff, ComEd recovers from RES and customers the costs for implementing and operating the program. A number of municipalities, including the City of Chicago have switched to RES electric supply. As a result, ComEd experienced a significant increase in the amount of RES receivables it purchased in 2013.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, as a result of the Illinois Settlement Legislation, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. On December 21, 2011, the ICC approved the IPA's procurement plan covering the period June 2012 through May 2017.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of the electricity it purchases for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive generation suppliers, whether as a result of the customers' own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd's purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the state's RPS. Under the Illinois Settlement Legislation, all associated costs are recoverable from customers.

As a result of reduced ComEd load forecasts, purchases under the existing long-term contracts for energy and the associated RECs were reduced on a pro-rata basis under the terms of those contracts for the June 2013—May 2014 period to keep the purchases under the statutory rate impact cap. The curtailment's impact on ComEd's financial position and cash flows was immaterial.

On December 18, 2013, the ICC approved the IPA's 2014-2019 procurement plan. The plan provides for two separate energy procurements during 2014 to address potential fluctuations in energy demand due to customer switching between ComEd and competitive electric generation suppliers. The Commission also approved the IPA's expansion of energy efficiency programs for both ComEd and Ameren. The ICC did not require the acquisition of additional renewable resources in 2014-2015 due to insufficient available funds to procure those resources. Further, the ICC again approved a reduction of purchases under the existing long-term contracts for energy and the associated RECs on a pro-rata basis under the terms of those contracts for the June 2014—May 2015 period to keep the purchases under the statutory rate impact cap; however the amount of the reduction will not be finalized and approved by the ICC until March 2014. The curtailment's impact on ComEd's financial position and cash flows is expected to be immaterial. See Note 12—Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation, which expired in May 2013, and long-term renewable energy contracts.

During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that the Utilities will pay FutureGen's contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs the Utilities to recover (or pass along) these costs from the Utilities' distribution system customers, regardless of whether they purchase electricity from the utility or from competitive electric generation suppliers. In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers.

On August 22, 2013, the Utilities executed the sourcing agreement with FutureGen in accordance with the ICC order. However, in the event the order is reversed as a result of the appeal, ComEd's obligations under the sourcing agreement should be suspended. Depending on the ultimate outcome of the appeals, the eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

See Note 22—Commitments and Contingencies for additional information on ComEd's energy commitments.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In December 2010, the ICC approved ComEd's second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013—May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, and additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Since June 1, 2008, utilities have been required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2013, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 22—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively. The electric settlement provides for recovery of PJM transmission service costs on a full and current basis through a rider. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2013. PECO currently anticipates that the IRS will issue guidance in early 2014 providing a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution rate cases. See Note 14 for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's first PAPUC approved DSP Program, under which PECO was providing default electric service, had a 29-month term that ended May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the DSP Programs, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. In addition, PECO's second DSP Program provides for the recovery of AEPS compliance costs through the GSA rather than a separate AEPS rider.

In the second DSP Program, PECO is procuring electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium, and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission's decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO's universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO's SMPIP, under which PECO will deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately

$120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of December 31, 2013, PECO has spent $423 million and $116 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of December 31, 2013, PECO has received $190 million of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $3 million as of December 31, 2013, which has been recorded in Other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor's meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $17 million, net of approximately $16 million of reimbursements from the DOE and approximately $2 million of depreciation. PECO requested and received approval from the DOE that the original meters continue to be allowable costs and that any agreement with the vendor will not be considered project income. In addition, PECO remains eligible for the full $200 million in SGIG funds. On August 15, 2013, PECO entered into an agreement with the original vendor, which was part of the final agreement discussed below, under which PECO transferred the original uninstalled meters to the vendor and will receive $12 million in return, of which $7 million has been received as of December 31, 2013. On January 23, 2014, PECO entered a final agreement with the vendor pursuant to which PECO will be reimbursed for amounts incurred for the original meters and related installation and removal costs, via cash payments and rebates on future purchases of licenses, goods and services primarily through 2017. PECO previously had intended to seek regulatory rate recovery in a future filing with the PAPUC of amounts not recovered from the vendor. As PECO believed such costs were probable of rate recovery based on applicable case law and past precedent on reasonably and prudently incurred costs, a regulatory asset was established at the time of the removals. As of December 31, 2013 and 2012, $5 million and $17 million, respectively, was recorded on Exelon's and PECO's Consolidated Balance Sheets. Pursuant to the January 23, 2014, vendor agreement, PECO will reclassify the regulatory asset balance as a receivable, with no gain or loss impacts on future results of operations.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013.

The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report for all Phase I targets, was filed with the PAPUC on November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition sought approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO's Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013. The order tentatively established PECO's three-year cumulative consumption reduction target at 1,125,852 MWh, which was reaffirmed by the PAPUC on December 5, 2012.

Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO's public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

On March 15, 2013, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million costs of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO's amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO's Energy Efficiency Program Charge along with all other Phase II Plan costs.

On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. The comment process is scheduled to be completed in the first quarter of 2014. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of

PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO has entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually in accordance with a PAPUC approved plan. The plan allowed PECO to bank AECs procured prior to 2011 and use the banked AECs to meet its AEPS Act obligations over two compliance years ending May 2013. The PAPUC also approved the procurement of Tier II AECs and supplemental AECs as well as the sale of excess AECs through independent third-party auctions or brokers.

All AEPS administrative costs and costs of AECs incurred after December 31, 2010 are being recovered on a full and current basis from default service customers through a surcharge.

PECO's second DSP Program eliminated the AEPS surcharge. Beginning in June 2013, AEPS compliance costs are being recovered through the GSA.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO's second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year rates are in effect. On August 2, 2012, the PAPUC issued a final order establishing rules and procedures to implement the ratemaking provisions of Act 11. The implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the Commission prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO's LTIIP for its Gas Operations, which was filed on February 8, 2013.

Maryland Regulatory Matters

2011 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period that began in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns a regulated rate of return.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE's 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs incurred during the test year, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance merger integration costs, which includes $6 million of costs incurred during 2012. Current MDPSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE's application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan in response to a MDPSC order through a surcharge separate from base rates. On August 23, 2013, BGE filed an update to its rate request which altered the requested increase to electric base rates from $101 million to $83 million and the requested increase to gas base rates from $30 million to $24 million. On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after December 13, 2013. The MDPSC also conditionally approved five of the eight programs included in BGE's proposed short-term reliability improvement plan. Commencement of the program and recovery are dependent on final MDPSC approval with the surcharge starting no earlier than April 1, 2014.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of December 31, 2013 and December 31, 2012, BGE recorded a regulatory asset of $66 million and $31 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE's Smart Grid program. In March 2013, BGE filed a description of the overall additional costs associated with allowing customers to retain their current meter, and for radio frequency (RF)-Free and RF-Minimizing options related to the installation of their smart meters as well as a proposed cost recovery mechanism. The MDPSC held a hearing in August 2013 to consider the filings made by BGE and other Maryland electric utilities. The ultimate resolution related to this feature could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system. Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE's ratepayers. The project to install the smart meters began in late April 2012. As of December 31, 2013, BGE had received $200 million in reimbursements from the DOE.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC's Order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of December 31, 2013, there is no impact on Exelon's and BGE's results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. On October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC's Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution. On November 22, 2013, the MDPSC and CPV appealed the District Court's ruling to the United States Court of Appeals for the Fourth Circuit.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under

Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. On October 29, 2013, BGE and the two other Maryland utilities appealed the Circuit Court's ruling to the Maryland Court of Special Appeals.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE's results of operations, cash flows and financial positions.

Exelon believes that this and other states' projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon's market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The MDPSC held evidentiary hearings on BGE's proposed plan and surcharge from November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers' bills. The new surcharges are expected to take effect in second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula.

ComEd's most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased capital investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE's most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower allowed rate of return associated with a reduced equity ratio and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory liability associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% included in the prior year formula update. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE's debt outstanding. As part of the FERC-approved settlement in 2006 of BGE's 2005 transmission rate case, the base rate of return on common equity for BGE's electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE's base return on equity to 8.7% (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the estimated annual impact would be a reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing of its March 30, 2012 Order and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. ComEd, and BGE anticipate that all impacts of any rate design changes effective after December 31, 2006 and June 30, 2006, respectively, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on their respective results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent that any rate design changes are retroactive to periods prior to January 1, 2011, however, there may be an impact on PECO's results of operations.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order. The compliance filing was made on July 22, 2013.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with

(Dollars in millions, except per share data unless otherwise noted)

PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE's estimated commitments are as follows:

	Total	2014	2015	2016	2017	2018
ComEd	$486	$134	$173	$177	$ 2	$—
PECO	133	32	29	40	24	8
BGE	400	42	83	95	87	93

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to FERC's approval of the MOPR were extensive, and there have been numerous changes to the MOPR and litigation related to it since it was originally implemented. For example, in 2011 the parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving that MOPR have been appealed to the United States Court of Appeals for the Third Circuit. A resolution of that appeal is not expected until sometime in 2014.

In May 2012 (based on the MOPR provisions the FERC approved in 2011), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, these states could expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believed that further revisions to that MOPR were necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM. In early December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which those MOPR changes were developed and supported the changes. On May 3, 2013, the FERC issued its order. While the FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Several entities, including two capacity suppliers that Exelon has been working with sought rehearing of that order.

In May 2013 (based on the MOPR provisions the FERC approved earlier that month), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2017. Exelon is working with PJM stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE file market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy, capacity, and ancillary services under market-based rate tariffs. FERC accepted the 2008 filings on September 16, 2008, January 15, 2009 and September 2, 2009 and accepted the 2009 filings on July 28, 2009, October 26, 2009, February 23, 2010 and April 30, 2010, affirming Exelon's affiliates continued right to make sales at market-based rates. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. Generation, ComEd, PECO and BGE filed an updated analysis for the Northeast Region, which includes PJM, in late 2010, based on 2009 historic test period data. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, based on Generation's most recent updated analysis filed in 2010, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation programs. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updates analysis for the Northeast Region, based on 2012 historic test period data and FERC has not yet acted on the filing. Similarly, on June 29, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012, and on December 23, 2011, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on October 10, 2012. On December 21, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the SPP region, which the FERC accepted on October 8, 2013.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2017 occurred in May 2013.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule which is now not expected until October 3, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. The current operating licenses for Byron Units 1 and 2 expire in 2024 and 2026, respectively. The current operating licenses for Braidwood Units 1 and 2 expire in 2026 and 2027, respectively. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until 2015 at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively.

The FERC extended the deadline to January 31, 2014 to file a water quality certification application pursuant to Section 401 of the Clean Water Act (CWA) with the MDE for Conowingo. Generation is working with stakeholders to resolve licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. Resolution of these issues relating to Conowingo may have a material effect on Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On August 29, 2013, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with PA DEP for Muddy Run, addressing these and other issues that included certain commitments made by Generation. The financial impact associated with these commitments is estimated to be in the range of $20 million to $30 million, and will include both an increase in capital expenditures as well as an increase in operating expenses. Exelon anticipates that the PA DEP will issue the water quality certification pursuant to Section 401 of the CWA for Muddy Run in the first quarter of 2014.

Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run's current license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications. The stations are currently being depreciated over their useful lives, which includes the license renewal period. As of December 31, 2013, $33 million of direct costs associated with relicensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

(Dollars in millions, except per share data unless otherwise noted)

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2013 and 2012.

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 221	$ 2,794	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	10	1,459	2	65	—	1,317	8	77
AMI programs	5	159	5	35	—	58	—	66
AMI meter events	—	5	—	—	—	5	—	—
Under-recovered distribution service costs	178	285	178	285	—	—	—	—
Debt costs	12	56	9	53	3	3	1	8
Fair value of BGE long-term debt	—	219	—	—	—	—	—	—
Fair value of BGE supply contract	12	—	—	—	—	—	—	—
Severance	16	12	12	—	—	—	4	12
Asset retirement obligations	1	102	1	67	—	25	—	10
MGP remediation costs	40	212	33	178	6	33	1	1
RTO start-up costs	2	—	2	—	—	—	—	—
Under-recovered uncollectible accounts	—	48	—	48	—	—	—	—
Under-recovered electric universal Renewable energy	17	176	17	176	—	—	—	—
Energy and transmission programs	53	—	52	—	—	—	1	—
Deferred storm costs	3	3	—	—	—	—	3	3
Electric generation-related regulatory asset	13	30	—	—	—	—	13	30
Rate stabilization deferral	71	154	—	—	—	—	71	154
Energy efficiency and demand response programs	73	148	—	—	—	—	73	148
Merger integration costs	2	9			—	—	2	9
Other	31	39	18	26	8	7	4	6
Total regulatory assets	$ 760	$ 5,910	$ 329	$ 933	$ 17	$ 1,448	$ 181	$ 524

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 2	$ 43	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,740	—	2,293	—	447	—	—
Removal costs	99	1,423	78	1,219	—	—	21	204
Energy efficiency and demand response programs	53	—	45	—	8	—	—	—
DLC program costs	1	10	—	—	1	10	—	—
Energy efficiency phase II	—	21	—	—	—	21	—	—
Electric distribution tax repairs	20	114	—	—	20	114	—	—
Gas distribution tax repairs	8	37	—	—	8	37	—	—
Energy and transmission programs	78	—	9	—	58	—	11	—
Over-recovered gas and electric universal service fund costs	8	—	—	—	8	—	—	—
Revenue subject to refund	38	—	38	—	—	—	—	—
Over-recovered electric and gas revenue decoupling	16	—	—	—	—	—	16	—
Other	4	—	—	—	3	—	—	—
Total regulatory liabilities	$ 327	$ 4,388	$ 170	$ 3,512	$ 106	$ 629	$ 48	$ 204

(Dollars in millions, except per share data unless otherwise noted)

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 304	$ 3,673	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	14	1,382	5	62	—	1,255	9	65
AMI programs	3	70	3	10	—	29	—	31
AMI meter events	—	17	—	—	—	17	—	—
Under-recovered distribution service costs	18	191	18	191	—	—	—	—
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt	—	256	—	—	—	—	—	—
Fair value of BGE supply contracts	77	12	—	—	—	—	—	—
Severance	29	28	25	12	—	—	4	16
Asset retirement obligations	—	90	—	65	—	25	—	—
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2	—	—	—	—
Under-recovered electric universal service fund costs	11	—	—	—	11	—	—	—
Financial swap with Generation	—	—	226	—	—	—	—	—
Renewable energy	18	49	18	49	—	—	—	—
Energy and transmission programs	43	—	14	—	1	—	28	—
DSP Program costs	1	3	—	—	1	3	—	—
DSP II Program costs	1	2	—	—	1	2	—	—
Deferred storm costs	3	6	—	—	—	—	3	6
Electric generation-related regulatory asset	16	40	—	—	—	—	16	40
Rate stabilization deferral	67	225	—	—	—	—	67	225
Energy efficiency and demand response programs	56	126	—	—	—	—	56	126
Under-recovered electric revenue decoupling	5	—	—	—	—	—	5	—
Other	23	25	14	16	9	8	—	2
Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,397	$ —	$ 2,037	$ —	$ 360	$ —	$ —
Removal costs	97	1,406	75	1,192	—	—	22	214
Energy efficiency and demand response programs	131	—	43	—	88	—	—	—
Electric distribution tax repairs	20	132	—	—	20	132	—	—
Gas distribution tax repairs	8	46	—	—	8	46	—	—
Over-recovered uncollectible accounts	6	—	6	—	—	—	—	—
Energy and transmission programs	54	—	6	—	48	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	2	—	—	—	2	—	—	—
Revenue subject to refund	40	—	40	—	—	—	—	—
Over-recovered gas revenue decoupling	7	—	—	—	—	—	7	—
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

Pension and other postretirement benefits. As of December 31, 2013, Exelon had regulatory assets of $3,015 million and regulatory liabilities of $45 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger. See Note 16—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd and BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. ComEd was granted recovery of these additional income taxes on May 24, 2011 in the ICC's 2010 Rate Case order. The recovery period for these costs is through May 31, 2014. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. See Note 14—Income Taxes and Note 16—Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents operating and maintenance expenses and meter costs associated with ComEd's AMI pilot program approved in the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods for operating and maintenance expenses and meter costs are through May 31, 2014, and January 1, 2020, respectively. As of December 31, 2013, ComEd had regulatory assets of $35 million related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the meter costs. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC's March 2011 rate order, is earning BGE's most current authorized rate of return. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an authorized rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown. BGE's AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as the MDPSC has ordered that the cost recovery for non-AMI meters will be considered in a future depreciation proceeding.

AMI Meter Events. This amount represents the remaining cost value of the original smart meters, net of accumulated depreciation, DOE reimbursements and amounts recovered from the vendor, of smart meter deployment that will no longer be used, including installation and removal costs. PECO intended to seek through regulatory rate recovery in a future filing with the PAPUC, any amounts no recovered from the vendor. PECO believed the amounts incurred for the original meters and related installation and removal costs were probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As such, PECO has deferred these costs on Exelon's and PECO's Consolidated Balance Sheet. PECO will not earn a return on the recovery of these costs.

Under-recovered distribution services costs. Under EIMA, which became effective in the fourth quarter of 2011, ComEd is allowed recovery of distribution services costs through a formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The over recovery associated with the 2011 reconciliation was recovered through rates over a one-year period, that began in January 2013. The under recovery associated with the 2012 reconciliation will be recovered through rates over a one-year period beginning in January 2014. ComEd is earning a return on these costs. The regulatory asset also includes costs associated with certain one-time events, such as large storms, which will be recovered over a five-year period. As of December 31, 2013, the regulatory asset was comprised of $377 million for the annual reconciliation and $86 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2013 balance related to significant one-time events contains $28 million of merger and integration related costs, net of amortization, incurred as a result of the merger. As of December 31, 2012, the regulatory asset was comprised of $125 million for the annual reconciliation and $84 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2012 balance related to significant one-time events contains $26 million of merger and integration related costs, net of amortization, incurred as a result of the merger. See Note 4—Mergers and Acquisitions for additional information.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's and BGE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs, while PECO is earning a return on the premium of the cost of the reacquired debt through base rates.

Fair value of BGE long-term debt. These amounts represent the regulatory asset recorded at Exelon for the difference in the fair value of the long-term debt of BGE as of the merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt.

Fair value of BGE supply contract. These amounts represent the regulatory asset recorded at Exelon representing the fair value of BGE's supply contracts as of the close of the merger date based on the MDPSC practice to allow BGE to recover its supply contracts through rates. Exelon is amortizing the regulatory asset and the associated fair value over a period of approximately three years.

Severance. For ComEd, these costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006, ICC rehearing rate order and the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods are through June 30, 2014, and May 31, 2014, respectively. ComEd is not earning a return on these costs. For BGE, these costs represent deferred severance costs that BGE has previously been granted recovery of in rates. Costs include the portion of costs associated with a 2008 workforce reduction that relate to BGE's gas business which were deferred in 2009 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Also included are costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Finally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. See Note 15—Asset Retirement Obligations for additional information.

MGP remediation costs. Recovery of these items was granted to ComEd in the July 26, 2006, ICC rate order. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. These costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. BGE is earning a return on this regulatory asset. See Note 22—Commitments and Contingencies for additional information.

RTO start-up costs. Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

Under (Over)-recovered universal service fund costs. The universal service fund cost is a recovery mechanism that allows PECO to recover discounts issued to electric and gas customers enrolled in assistance programs. As of December 31, 2013, PECO was over-recovered for both its electric and gas programs. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Financial swap with Generation. To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap contract with Generation that expired on May 31, 2013. Since the swap contract was deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period were recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd did not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position was based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price. In Exelon's consolidated financial statements, the fair value of the intercompany swap recorded by Generation and ComEd was eliminated.

Renewable Energy. On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price.

Energy and transmission programs. Starting in 2007, ComEd's energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd earns interest on under-recovered costs and pays interest on over-recovered costs to customers. The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, beginning in 2013, the deferred DSP I and II Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2013, PECO had a regulatory liability that included the over-recovered electric transmission costs of $8 million, $34 million related to the DSP program and $16 million related to over-recovered natural gas supply costs under the PGC. As of December 31, 2012, PECO had a regulatory asset related to under-recovered transmission costs of $1 million and a regulatory liability that included $47 million related to over-recovered electric supply costs under the GSA and $1 million related to over-recovered natural gas supply costs under the PGC. The BGE energy costs represent the electric and gas supply related costs recoverable (refundable) from (to) customers under BGE's market-based SOS and MBR programs, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. As of December 31, 2013, BGE had a regulatory asset of $1 million related to under-recovered electric supply costs and a regulatory liability of $11 million related to over-recovered natural gas supply costs. As of December 31, 2012, BGE had a regulatory asset of $9 million related to under-recovered electric supply costs and a regulatory asset of $19 million related to under-recovered natural gas supply costs.

DSP Program costs. These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO's PAPUC-approved DSP Program for the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. The filing and implementation costs of this DSP Program are recoverable through the GSA over its 29-month term, that began January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period after the PAPUC approves the results of the procurements. Costs relating to information technology improvements are recoverable over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. Beginning in 2013, these costs are included within the energy and transmission programs line item.

DSP II Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's second PAPUC-approved DSP program for the procurement of electric supply. The filing and procurement of this DSP Program are recoverable through the GSA over its 24-month term, that began June 1, 2013. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Beginning in 2013, these costs are included within the energy and transmission programs line item.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010. BGE is earning a return on this regulatory asset.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return were $37 million as of December 31, 2013, and $47 million as of December 31, 2012. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006, to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007, to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2013 and 2012, BGE recovered $66 million and $67 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan, PECO's PAPUC-approved EE&C Plan, and the BGE Smart Energy Savers Program®. ComEd began recovering these costs or refunding over-collections of these costs on June 1, 2008 through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. For PECO, this amount represents an over-collection of program costs related to both Phase I and Phase II of its EE&C Plan. PECO does not earn (pay) interest on under (over) collections. PECO began recovering the costs of its Phase I and Phase II EE&C Plans through a surcharge in January 2010 and June 2013, respectively, based on projected spending under the programs. Phase I recovery continued over the life of the program, which expired on May 31, 2013 and excess funds collected began being refunded in June 2013. Phase II of the program began on June 1, 2013, and will continue over the life of the program, which will expire on May 31, 2016. Excess funds collected are required to be refunded beginning in June 2016. PECO earned a return on the capital investment incurred under Phase I of the program. BGE's Smart Energy Savers Program® includes both MDPSC approved demand response and energy efficiency programs. For the BGE Peak Rewards SM demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013. Actual costs incurred in the conservation program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

Merger integration costs. These amounts represent integration costs to achieve distribution synergies related to the merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

Under (Over)-recovered electric and gas revenue decoupling. These amounts represent the electric and gas distribution costs recoverable from or refundable to customers under BGE's decoupling mechanism, which does not earn a rate of return. As of December 31, 2013, BGE had a regulatory liability of $7 million related to over-recovered electric revenue decoupling and $9 million related to over-recovered natural gas revenue decoupling. As of December 31, 2012, BGE had a regulatory asset of $5 million related to under-recovered electric revenue decoupling and a regulatory liability of $7 million related to over-recovered natural gas revenue decoupling.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for former ComEd and PECO plants that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. See Note 15—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred.

DLC Program Costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. No interest will be paid to customers.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Under (Over)-recovered uncollectible accounts. As a result of the February 2010 ICC order approving recovery of ComEd's uncollectible accounts, ComEd has the ability to adjust its rates annually to reflect the increases and decreases in annual uncollectible accounts expense starting with year 2008. ComEd recorded a regulatory asset for the cumulative under-collections in 2008 and 2009. Recovery of the initial regulatory asset was completed over an approximate 14-month time frame which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to the years starting with January 1, 2010, will take place over a 12-month time frame beginning in June of the following year. ComEd is not earning a return or paying interest on these under (over)-recovered costs.

Under (Over)-recovered AEPS costs current asset (liability). The AEPS costs represent the administrative and AEC costs incurred to comply with the requirements of the AEPS Act, which are recoverable on a full and current basis. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. Beginning in 2013, these costs are included within the energy and transmission programs line item.

Revenue subject to refund. These amounts represent refunds of $37 million and associated interest of $1 million ComEd owes to customers primarily related to the treatment of post-test year accumulated depreciation issue in the 2007 Rate Case. See above discussion of the 2007 Rate Case for further information.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd purchases receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. BGE's tariff provides that receivables are to be purchased at a discount, primarily to recover uncollectible accounts expense from the suppliers. However, if the discount rate is negative, the tariff provides that the receivable is purchased at a zero discount rate. BGE is currently purchasing certain receivables at a zero discount rate. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2013 and 2012.

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables [(a)]	$263	$ 105	$ 72	$86
Allowance for uncollectible accounts [(b)]	(30)	(16)	(7)	(7)
Purchased receivables, net	$233	$ 89	$ 65	$79

As of December 31, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables [(a)]	$ 191	$ 55	$ 65	$71
Allowance for uncollectible accounts [(b)]	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$65

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.
(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

(Dollars in millions, except per share data unless otherwise noted)

Regulatory Matters

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012.

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer (a)	Q2 2012	$ 113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	—	(2)	Taxes Other Than Income
Total		$139	$ 35	$328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining all required approvals, permits and financing for the construction of the building. Once required approvals are received and financing conditions are met, construction will commence and the building is expected to be ready for occupancy in approximately 2 years after building construction commences.

The direct investment estimate also includes $600 million to $650 million for Exelon's and Generation's commitment to develop or assist in development of 285—300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of December 31, 2013, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain of these commitments and achievement of commercial operation is expected in 2015. In December 2013, Generation acquired the Fourmile Ridge Project in western Maryland and executed a wind turbine supply agreement for construction of a 32.5 MW project targeted for commercial operation in November 2014. This project will satisfy a portion of the 125 MW Tier I land-based renewables commitment. See Note 22—Commitments and Contingencies for additional information. As of December 31, 2013, amounts reflected in the Exelon and Generation consolidated financial statements include $24 million of capital expenditures and $6 million of development costs included within operating and maintenance expense associated with pursuit of these commitments for new generation in the State of Maryland.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. The sale agreement included a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in net proceeds from the sale of approximately $371 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below Generation's estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $272 million in 2012 to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

In connection with the sale of the Maryland generating stations, Exelon agreed to indemnify Raven Power for certain costs associated with the treatment of hazardous substances at off-site disposal facilities and any claims arising as a result of, or in connection with, any toxic tort, natural resource damages, loss of life or injury to persons due to releases of, or exposure to hazardous substances in connection with Raven Power's remediation of environmental contamination or Exelon's non-compliance with environmental laws or permits prior to the closing date of the sale.

Pursuant to the MDPSC merger approval conditions, BGE is restricted from paying any dividend on its common shares through the end of 2014, was required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process for two years following the closing of the merger. Additionally, BGE is subject to other merger approval conditions to enhance BGE's ring-fencing measures established by order of the MDPSC.

Subsequent to the merger, Generation discovered that, for the first two weeks following the merger, due to a software error, Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation's proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation has coordinated with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. In November 2012, Generation reached a settlement with the DOJ regarding this matter. The final resolution did not have a material impact on Exelon's or Generation's results of operations, cash flows or financial position.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Merger Transaction

The fair value of Constellation's non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1—Significant Accounting Policies for additional information on BGE's push-down accounting treatment. Also see Note 3—Regulatory Matters for additional information on BGE's regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

(Dollars in millions, except per share data unless otherwise noted)

The final purchase price allocation of the Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation was as follows:

Preliminary Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Non-controlling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and non-controlling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues.

Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Generation's amortization expense for the year ended December 31, 2013 amounted to $470 million. Generation's amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $1,101 million. In addition, Exelon Corporate has established a regulatory asset and an unamortized energy contract liability related to BGE's power supply and fuel contracts. The power supply and fuel contracts regulatory asset amortization was $77 million for the year ended December 31, 2013 and $116 million for the period March 12, 2012 to December 31, 2012. An equally offsetting amortization of the unamortized energy contract liability has been recorded at Exelon Corporate in the Consolidated Statement of Operations.

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. Exelon's and Generation's straight line amortization expense for the fair value of the Constellation trade name intangible asset for the year ended December 31, 2013 and for the period March 12, 2012 to December 31, 2012 amounted to $26 million and $20 million, respectively. The trade name intangible asset is included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

(Dollars in millions, except per share data unless otherwise noted)

The fair value of the retail relationships was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets. Exelon's and Generation's straight line amortization expense for year ended December 31, 2013 and for the period March 12, 2012 to December 31, 2012 amounted to $21 million and $15 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

Exelon's intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of December 31, 2013:

					Estimated amortization expense					
Description	Weighted Average Amortization (Years) (b)	Gross	Accumulated Amortization	Net	2014	2015	2016	2017	2018	2019 and Beyond
Unamortized energy contracts, net (a)	1.5	$1,499	$ (1,378)	$ 121	$ 75	$ 18	$(31)	$(21)	$ 11	$ 69
Trade name	10.0	243	(46)	197	24	24	24	24	24	77
Retail relationships	12.4	214	(36)	178	19	18	18	18	18	87
Total, net		$1,956	$ (1,460)	$496	$118	$60	$ 11	$ 21	$53	$ 233

(a) Includes the fair value of BGE's power and gas supply contracts of $12 million for which an offsetting Exelon Corporate regulatory asset was also recorded.
(b) Weighted average amortization period was calculated as of the date of acquisition.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the year ended December 31, 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation's operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $3,065 million and $2,091 million and net income (loss) of $210 million and $(31) million during the years ended December 31, 2013 and December 31, 2012, respectively.

During the year ended December 31, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $142 million, $106 million, $16 million, $9 million and $6 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $17 million, $11 million and $6 million, respectively, as a regulatory asset as of December 31, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of December 31, 2013 for previously incurred 2012 merger and integration-related costs.

(Dollars in millions, except per share data unless otherwise noted)

During the year ended December 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $804 million, $340 million, $41 million, $17 million and $182 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $58 million, $36 million and $22 million, respectively, as a regulatory asset as of December 31, 2012.

The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for years ended December 31, 2013 and 2012. See Note 22—Commitments and Contingencies for additional information.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon's and Generation's accounting policies and adjusting Constellation's results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Generation		Exelon	
	Year Ended December 31,		Year Ended December 31,	
(unaudited)	2012	2011 [(a)]	2012	2011 [(b)]
Total Revenues	$17,013	$ 19,494	$26,700	$ 30,712
Net income attributable to Exelon	1,205	324	2,092	974
Basic Earnings Per Share	n.a.	n.a.	$ 2.56	$ 1.15
Diluted Earnings Per Share	n.a.	n.a.	2.55	1.14

(a) The amounts above include non-recurring costs directly related to the merger of $203 million for the year ended December 31, 2011.
(b) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.

Acquisitions (Exelon and Generation)

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices. Additionally, market prices based on the Market Price Referent (MPR) established by the CPUC for renewable energy resources were used in determining the fair value of the Antelope Valley assets acquired and liabilities assumed. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. Generation did not record any goodwill related to any of the respective acquisitions.

(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for each of the companies acquired by Generation during the year ended December 31, 2011:

	Acquisitions 2011	
	Wolf Hollow	Antelope Valley
Fair value of consideration transferred		
Cash	$ 305	$ 75
Plus: Gain on PPA settlement	6	—
Total fair value of consideration transferred	$ 311	$ 75
Recognized amounts of identifiable assets acquired and liabilities assumed		
Property, plant and equipment	$ 347	$ 15
Inventory	5	—
Intangible assets [(a)]	—	190
Payable to First Solar, Inc. [(b)]	—	(135)
Working capital, net	(5)	—
Other Assets	—	5
Total net identifiable assets	$ 347	$ 75
Bargain purchase gain	$ 36	$ —

(a) See Note 10—Intangible Assets for additional information.
(b) Generation concluded that the remaining, yet-to-be paid $135 million in consideration was embedded in the amounts payable under the Engineering, Procurement, Construction (EPC) agreement for First Solar, Inc. to construct the solar facility. For accounting purposes, this aspect of the transaction is considered to be akin to a "seller financing" arrangement. As such, Generation recorded a liability of $135 million associated with the portion of the future payments to First Solar, Inc. under the EPC agreement to reflect Generation's implicit amounts due First Solar, Inc. for the remainder of the value of the net assets acquired. The $135 million payable to First Solar, Inc. will be relieved as Generation makes payments for costs incurred over the project construction period. At December 31, 2012, $87 million remained payable to First Solar, Inc. During 2013, a subsidiary of Generation paid off the remaining balance of the payable to First Solar, Inc.

Wolf Hollow, LLC. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 720 MWs. The acquisition supports the Exelon commitment to low-carbon generation as part of Exelon 2020.

Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). The gain was included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the year ended December 31, 2011.

Antelope Valley Solar Ranch One. On September 30, 2011, Generation announced the completion of its acquisition of all of the interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

(Dollars in millions, except per share data unless otherwise noted)

Exelon expects to invest up to $650 million in equity in the project through 2014. The DOE's Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the project. See Note 13—Debt and Credit Agreements for additional information on the DOE loan guarantee.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the year ended December 31, 2011.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation's total equity in earnings (losses) on the investment in CENG is as follows:

	Year Ended December 31, 2013	Period March 12, through December 31, 2012
Equity investment income	$ 123	$ 73
Amortization of basis difference in CENG	(114)	(172)
Total equity in earnings (losses)—CENG	$ 9	$ (99)

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities affect the earnings of CENG.

Based on tax sharing provisions contained in the operating agreement for CENG, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest. Through purchase accounting, Generation has recorded the fair value of expected future distributions. When these distributions are realized, Generation will record a reduction in its investment in CENG. Any distributions in excess of Generation's investment in CENG would be recorded in earnings.

Generation has various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements see Note 25—Related Party Transactions.

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

The Master Agreement requires CENG to make two pre-closing cash distributions to EDF and Generation, if CENG has cash in excess of reserves and the amount of an outstanding credit facility are available, through one of its wholly owned subsidiaries, as owners of the joint venture. Generation received the first distribution of $115 million in December 2013 and recorded it as a reduction to the Investment in CENG on Exelon's and Generation's Consolidated Balance Sheets. A second distribution will occur prior to the closing provided that CENG has sufficient available cash.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The NOSA will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, at closing, Generation will make a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG and in any event, payable upon the settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Also at closing, Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation's obligations under this indemnity.

(Dollars in millions, except per share data unless otherwise noted)

Currently, Exelon and Generation account for their investment in CENG under the equity method of accounting. The transfer of the operating licenses and corresponding operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize their equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation's balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon's and Generation's results of operations.

6. Accounts Receivable (Exelon, Generation, ComEd PECO and BGE)

Accounts receivable at December 31, 2013 and 2012 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

2013	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,151	$584 (a)	$201	$161	$205
Allowance for uncollectible accounts (b)	(272)	(57)	(62)	(107) (c)	(46)

2012	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,094	$535 (a)	$213	$164	$182
Allowance for uncollectible accounts (b)	(293)	(84)	(70)	(99) (c)	(40)

(a) Represents unbilled portion of retail receivables estimated under Exelon's unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Includes an allowance for uncollectible accounts of $8 million and $7 million at December 31, 2013 and 2012, respectively, related to PECO's current installment plan receivables described below.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $19 million and $18 million as of December 31, 2013 and 2012, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2013 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2013 and 2012 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

(Dollars in millions, except per share data unless otherwise noted)

Accounts Receivable Agreement (Exelon and PECO). PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the accounts receivable designated under the agreement. As of December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $289 million, which represented the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest.

7. Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—transmission and distribution	5 - 90	$28,123	$26,576
Electric—generation	1 - 52	20,420	19,004
Gas—transportation and distribution	5 - 90	3,296	3,108
Common—electric and gas	5 - 50	1,101	1,029
Nuclear fuel (a)	1 - 8	5,196	4,815
Construction work in progress	N/A	1,890	1,926
Other property, plant and equipment (b)	1 - 51	1,017	912
Total property, plant and equipment		61,043	57,370
Less: accumulated depreciation (c)		13,713	12,184
Property, plant and equipment, net		$47,330	$45,186

(a) Includes nuclear fuel that is in the fabrication and installation phase of $947 million and $894 million at December 31, 2013 and 2012, respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $23 million and $20 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $59 million and total accumulated amortization was $36 million and $33 million as of December 31, 2013 and 2012, respectively. Also includes ComEd's buildings under capital lease with a net carrying value of $8 million and $0 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $0 million and $0 million as of December 31, 2013 and 2012, respectively. Includes land held for future use and non utility property at PECO and BGE. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities at Generation.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,371 million and $2,078 million as of December 31, 2013 and 2012, respectively.

(Dollars in millions, except per share data unless otherwise noted)

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

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric—transmission and distribution	2.91%	2.76%	2.59%
Electric—generation	3.35%	3.15%	3.12%
Gas	2.06%	2.03%	1.73%
Common—electric and gas	7.53%	7.61%	8.05%

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—generation	1 - 52	$20,420	$19,004
Nuclear fuel [(a)]	1 - 8	5,196	4,815
Construction work in progress	N/A	1,129	1,352
Other property, plant and equipment [(b)]	1 - 51	400	374
Total property, plant and equipment		27,145	25,545
Less: accumulated depreciation [(c)]		7,034	6,014
Property, plant and equipment, net		$ 20,111	$19,531

(a) Includes nuclear fuel that is in the fabrication and installation phase of $947 million and $894 million at December 31, 2013 and 2012, respectively.
(b) Includes buildings under capital lease with a net carrying value of $23 million and $20 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $59 million and total accumulated amortization was $36 million and $33 million as of December 31, 2013 and 2012, respectively. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities.
(c) Includes accumulated amortization of nuclear fuel in the reactor core of $2,371 million and $2,078 million as of December 31, 2013 and 2012, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.35%, 3.15% and 3.12% for the years ended December 31, 2013, 2012 and 2011, respectively.

License Renewals. Generation’s depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information regarding license renewals.

Plant Retirements

Schuylkill Station and Riverside Station. On October 31, 2012, Generation notified PJM of its intention to permanently retire Schuylkill Generating Station Unit 1 by February 1, 2013, and Riverside Generating Station Unit 6 by June 1, 2014. Schuylkill Unit 1 is a 166 MW peaking oil unit located in

Philadelphia, Pennsylvania, which was placed in service in 1958. Riverside Unit 6 is a 115 MW peaking gas/kerosene unit that was placed in service in 1970, located in Baltimore, Maryland. On December 1, 2013, Generation notified PJM of its intention to permanently retire Riverside Generating Station Unit 4 by June 1, 2016. Riverside Unit 4 is a 74 MW intermediate gas unit that was placed in service in 1951 also located in Baltimore, Maryland. The units are being retired because they are no longer economic to operate due to their age, relatively high capital and operating costs and declining revenue expectations. On November 30, 2012, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Schuylkill Unit 1 retirement date, and as a result, Schuylkill Unit 1 was retired on January 1, 2013. On January 7, 2013 and December 23, 2013, PJM notified Generation that it did not identify any transmission system reliability issues associated with the retirements of Riverside Units 6 and 4, respectively. The early retirements will not have a material impact on Generation or Exelon's results of operations, cash flows or financial position.

Eddystone Station and Cromby Station. In December 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011, in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on that date and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defined compensation to be paid to Generation for continuing to operate Cromby Unit 2 and Eddystone Unit 2. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 was approximately $6 million, and covered operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation was reimbursed for variable costs, including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 operated under the reliability-must-run agreement from June 1, 2011 until their respective retirement dates, Cromby Unit 2 on December 31, 2011 and Eddystone Unit 2 on May 31, 2012.

During the years ended December 31, 2013, 2012, and 2011, Generation incurred $1 million, $11 million, and $2 million of shut down costs reflected within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Expense for the write down of inventory was not material for the years ended December 31, 2013, 2012 and 2011.

(Dollars in millions, except per share data unless otherwise noted)

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

Asset Category	Average Service Life (years)	2013	2012
Electric—transmission and distribution	5 - 75	$17,334	$16,480
Construction work in progress	N/A	456	294
Other property, plant and equipment [(a)]	50	60	50
Total property, plant and equipment		17,850	16,824
Less: accumulated depreciation		3,184	2,998
Property, plant and equipment, net		$14,666	$13,826

(a) Includes buildings under capital lease with a net carrying value of $8 million and $0 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $0 million and $0 million as of December 31, 2013 and 2012, respectively.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.97%, 2.79% and 2.67% for the years ended December 31, 2013, 2012 and 2011, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

Asset Category	Average Service Life (years)	2013	2012
Electric—transmission and distribution	5 - 65	$6,669	$6,355
Gas—transportation and distribution	5 - 70	1,932	1,859
Common—electric and gas	5 - 50	600	568
Construction work in progress	N/A	101	76
Other property, plant and equipment [(a)]	50	17	17
Total property, plant and equipment		9,319	8,875
Less: accumulated depreciation		2,935	2,797
Property, plant and equipment, net		$6,384	$6,078

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

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

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric—transmission and distribution	2.73%	2.51%	2.33%
Gas	1.79%	1.77%	1.73%
Common—electric and gas	6.65%	7.54%	8.05%

(Dollars in millions, except per share data unless otherwise noted)

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—transmission and distribution	5 - 90	$ 6,100	$5,767
Gas—distribution	5 -90	1,660	1,548
Common—electric and gas	5 - 40	578	554
Construction work in progress	N/A	196	193
Other property, plant and equipment [(a)]	20	32	31
Total property, plant and equipment		8,566	8,093
Less: accumulated depreciation		2,702	2,595
Property, plant and equipment, net		$5,864	$5,498

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

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric—transmission and distribution	2.91%	2.92%	2.89%
Gas	2.36%	2.33%	2.41%
Common—electric and gas	8.45%	7.68%	8.40%

See Note 1—Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd, PECO and BGE. See Note 13—Debt and Credit Agreements for further information regarding Exelon's, ComEd's, and PECO's property, plant and equipment subject to mortgage liens.

8. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the third quarter of 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $43 million was recorded during the third quarter in operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations. Of the $43 million, $4 million was attributable to non-controlling interests for certain of the wind projects.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 14—Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third-party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

(Dollars in millions, except per share data unless otherwise noted)

Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $14 million pre-tax impairment charge in the second quarter of 2013, which was recorded in investments and operating and maintenance expense in the Consolidated Balance Sheet and the Consolidated Statement of Operations, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

As of December 31, 2012, Exelon concluded that the estimated fair values of the residual values at the end of the lease terms exceeded the residual values established at the lease dates.

At December 31, 2013 and December 31, 2012, the components of the net investment in long-term leases were as follows:

	December 31, 2013	December 31, 2012
Estimated residual value of leased assets	$ 1,465	$ 1,492
Less: unearned income	767	807
Net investment in long-term leases	$ 698	$ 685

9. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO and BGE)

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2013 and 2012 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem [a]	Keystone [b]	Conemaugh [b]	Wyman	PA [c]	DE/NJ [d]	Other [e]
Operator	Generation	Generation	PSEG Nuclear	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	41.98%	31.28%	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2013:									
Plant [f]	$ 941	$ 883	$ 501	$ 725	$ 399	$ 3	$ 14	$ 64	$ 2
Accumulated depreciation [f]	226	326	134	268	220	3	7	34	1
Construction work in progress	27	174	24	6	121	—	—	—	—
Exelon's share at December 31, 2012:									
Plant [f]	$ 874	$ 796	$ 494	$ 624	$ 322	$ 3	$ 13	$ 65	$ 1
Accumulated depreciation [f]	187	302	119	153	158	3	7	33	—
Construction work in progress	44	115	11	10	57	—	1	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2013 and 2012.
(b) Generation's ownership interest in Keystone and Conemaugh has increased as a result of Exelon's merger with Constellation in 2012. See Note 4—Merger and Acquisitions for additional information.
(c) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500 kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.

(Dollars in millions, except per share data unless otherwise noted)

(d) PECO owns a 42.55% share in 131 miles of 500 kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(e) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.
(f) Excludes asset retirement costs.

Exelon's, Generation's, PECO's and BGE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's and BGE's share of direct expenses of the jointly owned plants are included in fuel and operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and in operating and maintenance expenses on PECO's and BGE's Consolidated Statements of Operations.

10. Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2013 and 2012 were as follows:

	Gross Amount (a)	Accumulated Impairment Losses	Carrying Amount
Balance, January 1, 2012	$ 4,608	$ 1,983	$2,625
Impairment losses	—	—	—
Balance, December 31, 2013	$ 4,608	$ 1,983	$2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and is regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which discrete financial information is regularly reviewed by segment management. Therefore, ComEd's operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations.

ComEd's valuation approach is based on a market participant view, pursuant to authoritative guidance for fair value measurement, and utilizes a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case" or "best estimate" projected cash flows for ComEd's business and includes an estimate of ComEd's terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon's enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2013 Goodwill Impairment Assessments. Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd's earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the annual impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

In both the interim and annual assessments, the discounted cash flow analysis reflected Exelon's indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd's equity. While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business, and the fair value of debt could potentially result in a future impairment of ComEd's goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test.

Prior Goodwill Impairment Assessments. Management concluded that the May 2012 ICC final Order in ComEd's 2011 formula rate proceeding triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of May 31, 2012. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management's best estimate of projected operating and capital cash flows for ComEd's business (including the impacts of the May 2012 Order) as well as changes in certain other market conditions, such as the discount rate and EBITDA multiples.

(Dollars in millions, except per share data unless otherwise noted)

Other Intangible Assets

For discussion surrounding Exelon's and Generation's unamortized energy contracts, trade name and retail relationships recorded in conjunction with the Merger, refer to Note 4—Merger and Acquisitions.

Exelon's, Generation's and ComEd's other intangible assets, included in unamortized energy contract assets and deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2013:

	Weighted Average Amortization Years [(e)]	Gross	Accumulated Amortization	Net	Estimated amortization expense				
					2014	2015	2016	2017	2018
Generation [(f)]									
Exelon Wind acquisition [(a)]	18.0	$224	$ (41)	$183	$14	$14	$14	$14	$14
Antelope Valley acquisition [(b)]	25.0	190	(4)	186	8	8	8	8	8
ComEd									
Chicago settlement—1999 agreement [(c)]	21.8	100	(76)	24	3	3	3	4	4
Chicago settlement—2003 agreement [(d)]	17.9	62	(38)	24	4	4	4	3	3
Total intangible assets		$576	$ (159)	$417	$29	$29	$29	$29	$29

(a) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735 MWs of installed, operating wind capacity located in eight states.
(b) Refer to Note 4—Merger and Acquisitions for additional information regarding Antelope Valley.
(c) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.
(d) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third-party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in other long-term liabilities, are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.
(e) Weighted-average amortization period was calculated at the date of acquisition for acquired assets or settlement agreement.
(f) Excludes $67 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time.

(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation	ComEd
2013	$ 27	$ 20	$ 7
2012	20	13	7
2011	19	12	7

Acquired Intangible Assets

Accounting guidance for business combinations requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. The valuation of the acquired intangible assets discussed below were estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the respective PPAs. Key assumptions used in the valuation of these intangible assets include forecasted power prices and discount rates. Those measures are based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The intangible assets are amortized as a decrease in operating revenue within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income over the term of the underlying PPAs.

Exelon Wind. The output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which is recorded in unamortized energy contract assets within Exelon's and Generation's Consolidated Balance Sheets. The intangible assets are amortized on a straight-line basis over the period in which the associated contract revenues are recognized.

Antelope Valley. Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric Company. The excess of the contract price of the PPA over forecasted MPR-based market prices was recognized as an intangible asset at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible asset was approximately $190 million, which is recorded in unamortized energy contract assets within Exelon's and Generation's Consolidated Balance Sheets. The fair value is amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition date.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd and PECO).

Exelon's, Generation's, ComEd's and PECO's other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation and ComEd) and AECs (Exelon and PECO). Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2013, and 2012, PECO had current AECs of $19 million and $17 million, respectively, and noncurrent AECs of $5 million and $9 million, respectively. As of December 31, 2013, and 2012, Generation had current RECs of $158 million and $61 million, respectively, and noncurrent RECs of $0 million and $45 million, respectively. As of December 31, 2013, and 2012, ComEd, had current RECs of $3 million and $4 million, respectively. See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies for additional information on RECs and AECs.

(Dollars in millions, except per share data unless otherwise noted)

11. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of December 31, 2013, and 2012:

Exelon

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 344	$ 3	$ 341	$ —	$ 214	$ 214
Long-term debt (including amounts due within one year)	19,132	—	18,672	1,079	18,745	20,520
Long-term debt to financing trusts	648	—	—	631	648	664
SNF obligation	1,021	—	790	—	1,020	763
Preferred securities of subsidiary	—	—	—	—	87	82

Generation

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 22	$ —	$ 22	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	7,729	—	6,586	1,062	7,483	7,849
SNF obligation	1,021	—	790	—	1,020	763

ComEd

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 184	$ —	$ 184	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	5,675	—	6,238	17	5,567	6,548
Long-term debt to financing trust	206	—	—	202	206	212

PECO

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ —	$ —	$ —	$ —	$ 210	$ 210
Long-term debt (including amounts due within one year)	2,197	—	2,358	—	1,947	2,264
Long-term debt to financing trusts	184	—	—	180	184	188
Preferred securities	—	—	—	—	87	82

(Dollars in millions, except per share data unless otherwise noted)

BGE

	December 31, 2013				December 31, 2012	
	Carrying	Fair Value			Carrying	Fair
	Amount	Level 1	Level 2	Level 3	Amount	Value
Short-term liabilities	$ 138	$ 3	$ 135	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	2,011	—	2,148	—	2,178	2,468
Long-term debt to financing trusts	258	—	—	249	258	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO's accounts receivable agreement (Level 2), and dividends payable (Level 1). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 13 —Debt and Credit Agreements for additional information on PECO's accounts receivable agreement.

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

The fair value of Generation's non-government-backed fixed rate project financing debt (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-back fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public. PECO redeemed all outstanding series of preferred securities on May 1, 2013. See Note 20—Earnings Per Share and Equity for additional information.

Recurring Fair Value Measurements

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

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities and funds, certain exchange-based derivatives, and money market funds.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- Level 3—unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded securities and derivatives, and investments priced using an alternative pricing mechanism or third party valuation.

(Dollars in millions, except per share data unless otherwise noted)

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 1,230	$ —	$ —	$ 1,230
Nuclear decommissioning trust fund investments				
Cash equivalents	459	—	—	459
Equity				
Individually held	1,776	—	—	1,776
Exchange traded funds	115	—	—	115
Commingled funds	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87
Corporate debt securities	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7
Mutual funds	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending	—	—	314	314
Private Equity	—	—	5	5
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal [(b)]	3,232	4,494	350	8,076
Pledged assets for Zion decommissioning				
Cash equivalents	—	26	—	26
Equity				
Individually held	16	—	—	16
Equity funds subtotal	16	—	—	16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20
Corporate debt securities	—	227	—	227
Fixed income subtotal	45	251	—	296
Middle market lending	—	—	112	112
Other debt obligations	—	1	—	1
Pledged assets for Zion decommissioning subtotal [(c)]	61	278	112	451

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [(d)(e)]	54	—	—	54
Rabbi trust investments subtotal	56	—	—	56
Commodity mark-to-market derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [(f)]	(863)	(3,131)	(430)	(4,424)
Commodity mark-to-market assets subtotal	(46)	766	577	1,297
Interest rate mark-to-market derivative assets	30	39	—	69
Effect of netting and allocation of collateral	(30)	(2)	—	(32)
Interest rate mark-to-market derivative assets subtotal	—	37	—	37
Other Investments	—	—	15	15
Total assets	4,533	5,575	1,054	11,162
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [(f)]	869	3,007	404	4,280
Commodity mark-to-market liabilities subtotal [(h)]	1	(139)	(305)	(443)
Interest rate mark-to-market derivative liabilities	(31)	(17)	—	(48)
Effect of netting and allocation of collateral	31	1	—	32
Interest rate mark-to-market derivative liabilities subtotal	—	(16)	—	(16)
Deferred compensation obligation	—	(114)	—	(114)
Total liabilities	1	(269)	(305)	(573)
Total net assets	$4,534	$ 5,306	$ 749	$10,589

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 995	$ —	$ —	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Individually held	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [(b)]	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents	—	23	—	23
Equity				
Individually held	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion decommissioning subtotal [(c)]	132	386	89	607
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [(d)(e)]	69	—	—	69
Rabbi trust investments subtotal	71	—	—	71

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral (f)	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal (g)	80	1,076	656	1,812
Interest rate mark-to-market derivative assets	—	114	—	114
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	63	—	63
Other Investments	2	—	17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral (f)	2,042	4,020	25	6,087
Commodity mark-to-market liabilities (g)(h)	(83)	(228)	(289)	(600)
Interest rate mark-to-market liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation obligation	—	(102)	—	(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$ 10,050

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $(5) million and $30 million at December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million at both December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts include $53 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012.
(e) Excludes $32 million and $28 million of the cash surrender value of life insurance investments at December 31, 2013 and December 31, 2012, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(g) The Level 3 balance does not include current assets for Generation and current liabilities for ComEd of $226 million at December 31, 2012 related to the fair value of Generation's financial swap contract with ComEd.
(h) The Level 3 balance includes the current and noncurrent liability of $17 million and $176 million at December 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(Dollars in millions, except per share data unless otherwise noted)

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013 and 2012:

For the Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 367	$ 17	$ 656
Total realized / unrealized gains (losses)					
Included in net income	2	—	(44)[(a)]	—	(42)
Included in other comprehensive income	—	—	—	2	2
Included in regulatory assets	8	—	(126)[(b)]	—	(118)
Change in collateral	—	—	7	—	7
Purchases, sales, issuances and settlements					
Purchases	203	62	28	4	297
Sales	(28)	(39)	(11)	(8)	(86)
Settlements	(18)	—	—	—	(18)
Transfers into Level 3	—	—	86 [(c)]	1	87
Transfers out of Level 3	—	—	(35)	(1)	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 272	$ 15	$ 749
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held as of December 31, 2013	$ 1	$ —	$ 167	$ —	$ 168

(a) Includes a reduction for the reclassification of $211 million of realized gains due to settlement of derivative contracts recorded in results of operations for the year ended December 31, 2013.
(b) Excludes decreases in fair value of $11 million of and realized losses reclassified due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.

(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives [(b)]	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 17	$ —	$ 67
Total realized / unrealized gains (losses)					
Included in income	—	—	59[(a)]	—	59
Included in regulatory liabilities	1	—	39	—	40
Change in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334[(c)]	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39	—	39
Transfers out of Level 3	—	—	(89)	—	(89)
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$656
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2012	$ —	$ —	$ 214	$ —	$214

(a) Includes a reduction for the reclassification of $155 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.
(b) Excludes $98 million of increases in fair value and $566 million of realized losses due to settlements for the year ended December 31, 2012 of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements. This position was de-designated as a cash flow hedge prior to the merger date.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net [(a)]
Total gains (losses) included in income for the year ended December 31, 2013	$ (152)	$ 108	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 40	$ 127	$ 1

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains included in income for the year ended December 31, 2012	$ 54	$ 5	$—
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ 230	$ (16)	$—

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

(Dollars in millions, except per share data unless otherwise noted)

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 1,006	$ —	$ —	$ 1,006
Nuclear decommissioning trust fund investments				
Cash equivalents	459	—	—	459
Equity				
Individually held	1,776	—	—	1,776
Exchange traded funds	115	—	—	115
Commingled funds	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87
Corporate debt securities	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7
Mutual funds	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending	—	—	314	314
Private Equity	—	—	5	5
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal [(b)]	3,232	4,494	350	8,076
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	26	—	26
Equity				
Individually held	16	—	—	16
Equity funds subtotal	16	—	—	16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20
Corporate debt securities	—	227	—	227

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Fixed income subtotal	45	251	—	296
Middle market lending	—	—	112	112
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal (c)	61	278	112	451
Rabbi trust investments				
Mutual funds (d)	13	—	—	13
Rabbi trust investments subtotal	13	—	—	13
Commodity mark-to-market derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral (e)	(863)	(3,131)	(430)	(4,424)
Commodity mark-to-market assets subtotal	(46)	766	577	1,297
Interest Rate mark-to-market derivative assets	30	32	—	62
Effect of netting and allocation of collateral	(30)	(2)	—	(32)
Interest Rate mark-to-market derivative assets subtotal	—	30	—	30
Other investments	—	—	15	15
Total assets	4,266	5,568	1,054	10,888
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(540)	(1,890)	(397)	(2,827)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral (e)	869	3,007	404	4,280
Commodity mark-to-market liabilities subtotal	1	(139)	(112)	(250)
Interest rate mark-to-market derivative liabilities	(31)	(13)	—	(44)
Effect of netting and allocation of collateral	31	1	—	32
Interest rate mark-to-market derivative liabilities subtotal	—	(12)	—	(12)
Deferred compensation obligation	—	(29)	—	(29)
Total liabilities	1	(180)	(112)	(291)
Total net assets	$4,267	$ 5,388	$ 942	$ 10,597

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 487	$ —	$ —	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Individually held	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [(b)]	2,782	4,253	183	7,218
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	23	—	23
Equity				
Individually held	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [(c)]	132	386	89	607
Rabbi trust investments				
Cash equivalents	1	—	—	1
Mutual funds [(d)]	13	—	—	13

(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Rabbi trust investments subtotal	14	—	—	14
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [f]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal	80	1,076	882	2,038
Interest rate mark-to-market derivative assets	—	101	—	101
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	50	—	50
Other investments	2	—	17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [f]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation obligation	—	(28)	—	(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $(5) million and $30 million at December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million at both December 31, 2013 December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $10 million and $8 million of the cash surrender value of life insurance investments at December 31, 2013 and December 31, 2012, respectively.
(e) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(f) The Level 3 balance includes current assets for Generation of $226 million at December 31, 2012 related to the fair value of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

(Dollars in millions, except per share data unless otherwise noted)

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013, and 2012:

For the Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 660	$ 17	$ 949
Total unrealized / realized gains (losses)					
Included in income	2	—	(51)[(a)(b)]	—	(49)
Included in other comprehensive income	—	—	(219)[(b)]	2	(217)
Included in noncurrent payables to affiliates	8	—	—	—	8
Change in collateral	—	—	7	—	7
Purchases, sales, issuances and settlements					
Purchases	203	62	28	4	297
Sales	(28)	(39)	(11)	(8)	(86)
Settlements	(18)	—	—	—	(18)
Transfers into Level 3	—	—	86[(c)]	1	87
Transfers out of Level 3	—	—	(35)	(1)	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942
The amount of total losses included in income attributed to the change in unrealized gains related to assets and liabilities held as of December 31, 2013	$ 1	$ —	$ 156	$ —	$ 157

(a) Includes a reduction for the reclassification of $207 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2013.
(b) Includes $11 million of increases in fair value and realized losses due to settlements of $215 million associated with Generation’s financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon’s Consolidated Financial Statements.
(c) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.

(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 817	$ —	$ 867
Total realized / unrealized gains (losses)					
Included in income	—	—	66(a)	—	66
Included in other comprehensive income	—	—	(475)(b)	—	(475)
Included in noncurrent payables to affiliates	1	—	—	—	1
Changes in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334(c)	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39	—	39
Transfers out of Level 3	—	—	(89)	—	(89)
Balance as of December 31, 2012	$ 183	$ 89	$ 660	17	$ 949
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2012	$ —	$ —	$ 165	$ —	$ 165

(a) Includes a reduction for the reclassification of $99 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.
(b) Includes $98 million of increases in fair value and $566 million of realized losses reclassified from OCI due to settlements associated with Generation's financial swap contract with ComEd for the year ended December 31, 2012. This position was de-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013, and 2012:

	Operating Revenue	Purchased Power and Fuel	Other - net (a)
Total gains (losses) included in income for the year ended December 31, 2013	$ (158)	$ 107	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 30	$ 126	$ 1

	Operating Revenue	Purchased Power and Fuel	Other - net (a)
Total gains included in income for the year ended December 31, 2012	$ 61	$ 5	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ 181	$ (16)	$ —

(Dollars in millions, except per share data unless otherwise noted)

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Rabbi trust investments				
Mutual funds	5	—	—	5
Rabbi trust investments subtotal	5	—	—	5
Total assets	5	—	—	5
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities (b)	—	—	(193)	(193)
Total liabilities	—	(8)	(193)	(201)
Total net assets (liabilities)	$ 5	$ (8)	$ (193)	$ (196)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$ —	$ —	$ 111
Rabbi trust investments				
Mutual funds	8	—	—	8
Rabbi trust investments subtotal	8	—	—	8
Total assets	119	—	—	119
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities (a)(b)	—	—	(293)	(293)
Total liabilities	—	(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$(293)	$ (182)

(a) The Level 3 balance includes the current liability of $226 million at December 31, 2012, related to the fair value of ComEd's financial swap contract with Generation which eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(b) The Level 3 balance includes the current and noncurrent liability of $17 million and $176 million at December 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended and December 31, 2013, and 2012:

For the Year Ended December 31, 2013	Mark-to-Market Derivatives
Balance as of January 1, 2013	$ (293)
Total realized / unrealized gains included in regulatory assets (a)(b)	100
Balance as of December 31, 2013	$ (193)

(a) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with ComEd's financial swap contract with Generation for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(Dollars in millions, except per share data unless otherwise noted)

(b) Includes $133 million of increases in the fair value and realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2013.

Twelve Months Ended December 31, 2012	Mark-to-Market Derivatives
Balance as of January 1, 2012	$ (800)
Total realized / unrealized gains included in regulatory assets (a)(b)	507
Balance as of December 31, 2012	$ (293)

(a) Includes $98 million of increases in fair value and $566 million of realized gains due to settlements associated with ComEd's financial swap contract with Generation for the year ended December 31, 2012. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $34 million of decreases in the fair value and realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2012.

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 175	$ —	$ —	$ 175
Rabbi trust investments				
Mutual funds (a)	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	184	—	—	184
Liabilities				
Deferred compensation obligation	—	(17)	—	(17)
Total liabilities	—	(17)	—	(17)
Total net assets (liabilities)	$ 184	$ (17)	$ —	$ 167

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$ —	$ —	$ 346
Rabbi trust investments				
Mutual funds (a)	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	355	—	—	355
Liabilities				
Deferred compensation obligation	—	(18)	—	(18)
Total liabilities	—	(18)	—	(18)
Total net assets (liabilities)	$ 355	$ (18)	$ —	$ 337

(Dollars in millions, except per share data unless otherwise noted)

(a) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at December 31, 2013 and 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2013 and 2012.

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 31	$ —	$ —	$31
Rabbi trust investments				
Mutual funds	6	—	—	6
Rabbi trust investments subtotal	6	—	—	6
Total assets	37	—	—	37
Liabilities				
Deferred compensation obligation	—	(6)	—	(6)
Total liabilities	—	(6)	—	(6)
Total net assets (liabilities)	$ 37	$ (6)	$ —	$31

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$33
Rabbi trust investments				
Mutual funds	5	—	—	5
Rabbit trust investments subtotal	5	—	—	5
Total assets	38	—	—	38
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 38	$ (5)	$ —	$33

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2013.

Valuation Techniques Used to Determine Fair Value

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

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

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities are determined using a third party valuation that contains certain significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

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

Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 12—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon board of directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio are reviewed and verified by the middle office and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.92 and $0.12 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 7A. —QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 12—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

(Dollars in millions, except per share data unless otherwise noted)

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2013 [c]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic Hedges (Generation) [a]	$ 488	Discounted Cash Flow	Forward power price	$8 - $176[d]
			Forward gas price	$2.98 - $16.63[d]
		Option Model	Volatility percentage	15% - 142%
Mark-to-market derivatives—Proprietary trading (Generation) [a]	$ 3	Discounted Cash Flow	Forward power price	$10 - $176[d]
		Option Model	Volatility percentage	14% - 19%
Mark-to-market derivatives (ComEd)	$ (193)	Discounted Cash Flow	Forward heat rate [b]	8 - 9
			Marketability reserve	3.5% - 8%
			Renewable factor	84% -128%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
c) The fair values do not include cash collateral held on Level 3 positions of $26 million as of December 31, 2013.
d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $100 and $5.70, respectively.

Type of trade	Fair Value at December 31, 2012 [d]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic Hedges (Generation) [a]	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
			Forward gas price	$3.26 - $6.27
		Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives—Proprietary trading (Generation) [a]	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
		Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives—Transactions with affiliates (Generation and ComEd) [b]	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)	$ (67)	Discounted Cash Flow	Forward heat rate [c]	8% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd that ended in May 2013, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
d) The fair values do not include cash collateral held on Level 3 positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, certain corporate debt securities, and private equity investments the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its' Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its' Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

As of December 31, 2013, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, and private equity investments of approximately $448 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

12. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract that expired May 31, 2013. The financial swap was designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, met its load service requirements. The terms of the financial swap contract required Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd paid a fixed price.

As the contract expired May 31, 2013, all realized impacts have been included in Generation's and ComEd's results of operations. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

In addition, the physical contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3—Regulatory Matters, qualify and are accounted for under the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd's price risk related to power procurement is limited.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced in the first quarter of 2013. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3—Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting

PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts, that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2013 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2013 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 8,762 GWh, 12,958 GWh and 5,742 Gwh for the years ended December 31, 2013, 2012 and 2011, are a complement to

(Dollars in millions, except per share data unless otherwise noted)

Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2013. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of December 31, 2013.

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading (a)	Collateral and Netting (b)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 3	$ 15	$ (19)	$ (1)	$ —	$ (1)
Mark-to-market derivative assets (Noncurrent Assets)	26	3	15	(13)	31	7	38
Total mark-to-market derivative assets	$ 26	$ 6	$ 30	$ (32)	$ 30	$ 7	$ 37
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (18)	$ 19	$ (1)	$ —	$ (1)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(10)	(1)	(13)	13	(11)	(4)	(15)
Total mark-to-market derivative liabilities	$ (11)	$ (2)	$ (31)	$ 32	$ (12)	$ (4)	$ (16)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 4	$ (1)	$ —	$ 18	$ 3	$ 21

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the interest rate hedge balances recorded by the Registrants as of December 31, 2012:

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading (a)	Collateral and Netting (b)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 3	$ 20	$ (19)	$ 4	$ —	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	8	32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$ —	$ (2)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(31)	—	(32)	32	(31)	—	(31)
Total mark-to-market derivative liabilities	(32)	(1)	(51)	51	(33)	—	(33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$ —	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

		Twelve Months Ended December 31,					
		2013	2012	2011	2013	2012	2011
	Income Statement Location	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense (a)	$ (15)	$ (6)	$ —	$ —	$ (6)	$ —
Exelon	Interest expense	$ (24)	$ (9)	$ 1	$ 11	$ (3)	$ (1)

(a) For the years ended December 31, 2013 and 2012, the loss on Generation swaps included $16 million and $12 realized in earnings, respectively, with $2 million and an immaterial amount excluded from hedge effectiveness testing, respectively.

During the third and fourth quarters of 2013, Exelon entered into $625 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2020. At December 31, 2013, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with unrealized gains of $26 million and $23 million, respectively. At December 31, 2012, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $650 million and $550 million that expire in 2015, with unrealized gains of $49 million and $38 million, respectively. During the years ended December 31, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $2 million gain and immaterial, respectively.

Cash Flow Hedges. In anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013, Exelon entered into forward-starting interest rate swaps that were designated as cash flow hedges to hedge the change in benchmark interest rates. Upon settlement of the swaps, a $26 million effective gain in OCI was deferred and will be amortized into interest expense over the life of the debt. See Note 13—Debt and Credit Agreements for additional information on the project financing.

In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 13—Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and a series of additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $350 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $135 million. At December 31, 2013, Generation's mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $10 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $28 million as of December 31, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At December 31, 2013, the subsidiary had a $1 million derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $27 million as of December 31, 2013, and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2013, the subsidiary had a $2 million derivative asset related to the swap.

During the years ended December 31, 2013, and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At December 31, 2013, Generation had $144 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $195 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

At December 31, 2013, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $2 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the year ended December 31, 2013, and the period from March 12 to December 31, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place either as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy-related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of December 31, 2013 and 2012, $10 million of cash collateral posted and $3 million of cash collateral received, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

Derivatives	Generation Economic Hedges	Generation Proprietary Trading	Generation Collateral and Netting (a)	Generation Subtotal (b)	ComEd Economic Hedges (c)	Exelon Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,616	$ 1,476	$ (3,364)	$ 728	$ —	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,344	285	(1,060)	569	—	569
Total mark-to-market derivative assets	$ 3,960	$ 1,761	$ (4,424)	$ 1,297	$ —	$ 1,297
Mark-to-market derivative liabilities (current liabilities)	$ (2,023)	$ (1,410)	$ 3,292	$ (141)	$ (17)	$ (158)
Mark-to-market derivative liabilities (noncurrent liabilities)	(804)	(293)	988	(109)	(176)	(285)
Total mark-to-market derivative liabilities	$ (2,827)	$ (1,703)	$ 4,280	$ (250)	$ (193)	$ (443)
Total mark-to-market derivative net assets (liabilities)	$ 1,133	$ 58	$ (144)	$ 1,047	$ (193)	$ 854

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $84 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(12) million and $0 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $144 million at December 31, 2013.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	Economic Hedges [(a)]	Proprietary Trading	Collateral and Netting [(b)]	Subtotal [(c)]	Economic Hedges [(a)(d)]	Intercompany Eliminations [(a)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$ —	$ —	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226	—	—	226	—	(226)	—
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878	—	—	878
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$ 2,038	$ —	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$(2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$ —	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(226)	226	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)	—	(250)
Total mark-to-market derivative liabilities	$(3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$ 1,505	$ (293)	$ —	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $28 million of noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.
(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.
(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $ (214) million and $ (131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $ (31) million at December 31, 2012.
(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. Approximately $195 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation. Generation expects the settlement of the majority of its cash flow hedges will occur during 2013 through 2014.

(Dollars in millions, except per share data unless otherwise noted)

Exelon discontinues hedge accounting when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the year ended 2012, the amount reclassified into earnings as a result of the discontinuance of cash flow hedges was immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2013 and 2012, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2012		$ 925 [a][d]	$ 488
Effective portion of changes in fair value		432 [b]	330 [e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(828) [c]	(453)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at December 31, 2012		532 [a][d]	368
Effective portion of changes in fair value		—	29 [e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(413) [c]	(277)
Accumulated OCI derivative gain at December 31, 2013		$ 119 [d]	$ 120

(a) Includes $133 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011 .
(b) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the year ended December 31, 2012. As of the merger date, cash flow hedges were discontinued, as such, this amount represents changes in fair value prior to the merger date.
(c) Includes $133 million and $375 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2013 and 2012, respectively.
(d) Excludes $5 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2013 and 2012, respectively.
(e) Includes $15 million and $9 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the year ended December 31, 2013 and 2012, respectively.

During the years ended December 31, 2013, 2012, and 2011 Generation's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $683 million, $1,368 million and $968 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. Changes in cash flow hedge ineffectiveness were losses of $5 million and a gain of $10 million for the years ended 2012 and 2011, respectively.

(Dollars in millions, except per share data unless otherwise noted)

Exelon's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $464 million, $747 million and $512 million pre-tax gain for the years ended December 31, 2013, 2012 and 2011, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million and gains of $10 million for the years ended 2012 and 2011, respectively. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the years ended December 31, 2013, 2012 and 2011, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Intercompany Eliminations	Exelon
Year Ended December 31, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues [(a)]	Total
Change in fair value	$ 285	$ 180	$ 465	$ (6)	$ 459
Reclassification to realized at settlement	(65)	104	39	13	52
Net mark-to-market gains	$ 220	$ 284	$ 504	$ 7	$ 511

	Generation			Intercompany Eliminations	Exelon
Year Ended December 31, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues [(a)]	Total
Change in fair value	$ (362)	$ 215	$(147)	$ (94)	$(241)
Reclassification to realized at settlement	429	238	667	101	768
Net mark-to-market gains	$ 67	$ 453	$ 520	$ 7	$ 527

(Dollars in millions, except per share data unless otherwise noted)

Year Ended December 31, 2011 (As Reported)	Exelon and Generation Operating Revenues	Exelon and Generation Purchased Power and Fuel	Exelon and Generation Total
Change in fair value	$ 87	$ 131	$ 218
Reclassification to realized at settlement	(296)	(219)	(515)
Net mark-to-market (losses) [(b)]	$ (209)	$ (88)	$(297)

Year Ended December 31, 2011 (Pro Forma)	Exelon and Generation Operating Revenues	Exelon and Generation Purchased Power and Fuel	Exelon and Generation Total
Change in fair value	$ 258	$ (40)	$ 218
Reclassification to realized at settlement	(516)	1	(515)
Net mark-to-market (losses) [(b)]	$ (258)	$ (39)	$(297)

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.
(b) Exelon and Generation have historically presented mark-to-market gains and losses within purchased power expense for all non-trading, energy-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon and Generation classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale to hedge power, to operating revenues.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2013, and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	For the Years Ended December 31, 2013	2012	2011
Change in fair value	Operating Revenue	$(21)	$ (12)	$ 23
Reclassification to realized at settlement	Operating Revenue	(18)	108	(26)
Net mark-to-market gains (losses)	Operating Revenue	$(39)	$ 96	$ (3)

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

(Dollars in millions, except per share data unless otherwise noted)

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $38 million, $38 million and $27 million, respectively.

Rating as of December 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral (a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,621	$ 172	$ 1,449	$ 1	$ 491
Non-investment grade	27	9	18	—	—
No external ratings					
Internally rated—investment grade	416	1	415	1	226
Internally rated—non-investment grade	30	2	28	—	—
Total	$ 2,094	$ 184	$ 1,910	$ 2	$ 717

Net Credit Exposure by Type of Counterparty	December 31, 2013
Financial Institutions	$ 256
Investor-owned utilities, marketers, power producers	684
Energy cooperatives and municipalities	907
Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit .

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2013, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2013, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of December 31, 2013, BGE had no net credit exposure to suppliers.

(Dollars in millions, except per share data unless otherwise noted)

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature	For the Years Ended December 31, 2013	2012
Gross Fair Value of Derivative Contracts Containing this Feature (a)	$ (1,056)	$ (1,849)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements (b)	$ 846	$ 1,426
Net Fair Value of Derivative Contracts Containing This Feature (c)	$ (210)	$ (423)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $72 million, letters of credit posted of $364 million, cash collateral held of $206 million and letters of credit held of $34 million as of December 31, 2013 for counterparties with derivative positions. Generation had cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. BB+ or Ba1), Generation could be required to post additional collateral of $2.0 billion as of December 31, 2013 and December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2013, Generation's and Exelon's swaps were in an asset position, with a fair value of $18 million and $21 million, respectively.

See Note 24—Segment Information for additional information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2013, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2013, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 1—Significant Accounting Policies for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2013, PECO could have been required to post approximately $42 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

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

(Dollars in millions, except per share data unless otherwise noted)

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2013, BGE could have been required to post approximately $85 million of collateral to its counterparties.

13. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

Exelon, Generation, ComEd, PECO and BGE had the following amounts of commercial paper borrowings at December 31, 2013 and 2012:

Commercial Paper Issuer	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2013 (a)	2012 (a)	2013	2012	2013	2012
Exelon Corporate	$ 500	$ 500	$ —	$—	0.27%	0.47%
Generation	5,600	5,600	—	—	0.32%	0.45%
ComEd	1,000	1,000	184	—	0.40%	0.50%
PECO	600	600	—	—	n.a.	n.a.
BGE	600	600	135	—	0.31%	0.43%
Total	$8,300	$8,300	$319	$—		

(a) Equals aggregate bank commitments under the revolving and bilateral credit agreements (with the exception of a $75 million bilateral agreement) that backstop the commercial paper program. See discussion below and Credit Agreements table below for items affecting effective program size.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its outstanding commercial paper does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit agreement.

(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2013, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

Borrower	Aggregate Bank Commitment [(a)]	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2013: Actual	Available Capacity at December 31, 2013: To Support Additional Commercial Paper [(b)]
Exelon Corporate	$ 500	$ —	$ 2	$ 498	$ 498
Generation	5,675	—	1,413	4,262	4,187
ComEd	1,000	—	—	1,000	816
PECO	600	—	1	599	599
BGE	600	—	—	600	465
Total	$ 8,375	$ —	$ 1,416	$6,959	$ 6,565

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 17, 2014 and are solely for issuing letters of credit. As of December 31, 2013, letters of credit issued under these agreements totaled $20 million, $18 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively.
(b) Excludes $75 million bilateral credit facility that does not back Generation's commercial paper program.

For the year ended December 31, 2013, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, and BGE during 2013, 2012 and 2011. PECO did not have any short-term borrowings outstanding during 2013, 2012 or 2011.

Exelon

	2013	2012	2011
Average borrowings	$ 254	$ 199	$ 218
Maximum borrowings outstanding	682	505	600
Average interest rates, computed on a daily basis	0.37%	0.48%	0.50%
Average interest rates, at December 31	0.35%	n.a.	0.44%

Generation

	2013	2012	2011
Average borrowings	$ 42	$ 4	$ 51
Maximum borrowings outstanding	291	165	304
Average interest rates, computed on a daily basis	0.32%	0.45%	0.48
Average interest rates, at December 31	n.a.	n.a.	n.a.

(Dollars in millions, except per share data unless otherwise noted)

ComEd

	2013	2012	2011
Average borrowings	$ 203	$ 110	$ 36
Maximum borrowings outstanding	446	366	407
Average interest rates, computed on a daily basis	0.40%	0.50%	0.71%
Average interest rates, at December 31	0.37%	n.a.	n.a.

BGE

	2013	2012	2011
Average borrowings	$ 35	$ 6	$ 26
Maximum borrowings outstanding	135	76	190
Average interest rates, computed on a daily basis	0.31%	0.43%	0.38%
Average interest rates, computed at December 31	0.31%	n.a.	n.a.

Credit Agreements

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On August 10, 2013, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The new covenants are substantially consistent with existing covenants. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

Effective August 10, 2013, Exelon and ComEd entered into amendments to each of their respective revolving credit facilities (the Amendments). The Amendments relate to the IRS's challenge to the position taken by Exelon on its 1999 federal income tax return with respect to the sale of ComEd's fossil generating assets in a like-kind exchange tax position. The Amendments are intended to exclude the non-cash impact of the like-kind exchange tax position from the calculation of the interest coverage ratio under each of Exelon and ComEd's respective credit facilities. See Note 12—Income Taxes for additional information.

On January 27, 2014 ComEd began the process of extending its unsecured syndicated revolving credit facility, with aggregate bank commitments of $1.0 billion. The transaction is expected to close and become effective in March 2014, with a maturity of five years from the close of the transaction. No changes are expected to be made to the facility other than extension of the term for an additional one year period. Generally, it is expected that costs incurred to extend the facility will be amortized over the newly extended life of the facility.

(Dollars in millions, except per share data unless otherwise noted)

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

An event of default under any of the Registrants' credit facilities would not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility would constitute an event of default under the Exelon Corporate credit facility.

On October 18, 2013, Generation, ComEd, PECO and BGE refinanced their respective minority and community bank credit facility agreements in the amounts of $50 million, $34 million, $34 million and $5 million, respectively. These facilities, which expire in October 2014, are solely utilized to issue letters of credit.

Each credit facility requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit facility threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	7.67	11.45	5.20	8.29	7.85

Accounts Receivable Agreement

PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the accounts receivable designated under the agreement. As of December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $289 million, which represented the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest.

(Dollars in millions, except per share data unless otherwise noted)

Willis Tower Capital Lease

In the second quarter of 2013, ComEd entered into a 20-year capital lease for distribution substation space at Willis Tower in Chicago, Illinois. Exelon and ComEd recorded $8 million on their Consolidated Balance Sheets within property plant and equipment and long-term debt at the inception of the lease. ComEd will make lease payments of less than $1 million annually in 2013-2017 and approximately $7 million in aggregate thereafter.

Long-Term Debt

The following tables present the outstanding long-term debt at Exelon, Generation, ComEd, PECO and BGE as of December 31, 2013 and 2012:

Exelon

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
First Mortgage Bonds [(a)(b)]:				
Fixed rates	1.20% — 7.63%	2013-2043	$ 7,746	$ 7,397
Unsecured bonds	2.80% — 6.35%	2013-2036	1,750	1,850
Rate stabilization bonds	5.68% — 5.82%	2016-2017	265	332
Senior unsecured notes	2.00% — 7.60%	2014-2042	7,571	8,021
Pollution control notes:				
Fixed rates	4.10%	2014	20	20
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	1,077	238
Variable rates	1.96% — 2.77%	2013-2053	150	262
Notes payable and other [(c)]	4.50% — 7.83%	2014-2053	181	177
Total long-term debt			18,760	18,297
Unamortized debt discount and premium, net			(19)	(17)
Fair value adjustment			384	448
Fair value hedge carrying value adjustment, net			7	17
Long-term debt due within one year			(1,509)	(1,047)
Long-term debt			$ 17,623	$ 17,698
Long-term debt to financing trusts [(d)]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Trust	6.20%	2043	258	258
Total long-term debt to financing trusts			$ 648	$ 648

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes First Mortgage Bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.

(Dollars in millions, except per share data unless otherwise noted)

(c) Includes capital lease obligations of $41 million and $30 million at December 31, 2013 and 2012, respectively. Lease payments of $4 million, $4 million, $4 million, $5 million, $5 million and $19 million will be made in 2014, 2015, 2016, 2017, 2018 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
Senior unsecured notes	2.00% — 7.60	2014-2042	$6,271	$6,721
Social Security Administration	2.93%	2015	1	—
Pollution control notes:				
Fixed rates	4.10%	2014	20	20
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	1,077	238
Variable rates	1.96% — 2.77%	2014-2030	150	262
Notes payable and other [(a)]	4.50% — 7.83%	2014-2022	33	30
Total long-term debt			7,552	7,271
Fair value adjustment			166	199
Unamortized debt discount and premium, net			11	13
Long-term debt due within one year			(561)	(28)
Long-term debt			$7,168	$7,455

(a) Includes Generation's capital lease obligations of $33 million and $30 million at December 31, 2013 and 2012, respectively. Generation will make lease payments of $4 million, $4 million, $4 million, $5 million, $5 million and $11 million in 2014, 2015, 2016, 2017, 2018 and thereafter, respectively.

During January 2014, Generation redeemed its $20 million 4.10% pollution control revenue bonds due July 1, 2014 and its $500 million 5.35% senior unsecured notes at maturity.

ComEd

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
First Mortgage Bonds [(a)(b)]:				
Fixed rates	1.63% — 7.63%	2013-2043	$5,546	$5,447
Notes payable and other [(c)]	6.95% — 7.49%	2014-2053	148	140
Total long-term debt			5,694	5,587
Unamortized debt discount and premium, net			(19)	(20)
Long-term debt due within one year			(617)	(252)
Long-term debt			$ 5,058	$ 5,315
Long-term debt to financing trust [(d)]				
Subordinated debentures to ComEd Financing III	6.35%	2042	$ 206	$ 206

(Dollars in millions, except per share data unless otherwise noted)

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the ComEd mortgage indenture securing pollution control bonds and notes.
(c) Includes ComEd's capital lease obligations of $8 million at December 31, 2013. Lease payments of less than $1 million will be made from 2014 through expiration at 2053.
(d) Amount owed to this financing trust is recorded as debt to financing trust within ComEd's Consolidated Balance Sheets.

On January 10, 2014, ComEd issued $300 million aggregate principal amount of its First Mortgage 2.150% Bonds, Series 115, due January 15, 2019, and $350 million aggregate principal amount of its First Mortgage 4.700% Bonds, Series 116, due January 15, 2044. The proceeds of the Bonds were used by ComEd to refinance the $17 million outstanding principal amount of its First Mortgage 5.850% Bonds, Pollution Control Series 1994C, due January 15, 2014, and the $600 million outstanding principal amount of its First Mortgage 1.625% Bonds, Series 110, due January 15, 2014, and to fund other general corporate purposes in 2014.

PECO

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
First Mortgage Bonds [(a)(b)]:				
Fixed rates	1.20% — 5.95%	2013-2043	$2,200	$1,950
Total long-term debt			2,200	1,950
Unamortized debt discount and premium, net			(3)	(3)
Long-term debt due within one year			(250)	(300)
Long-term debt			$1,947	$1,647
Long-term debt to financing trusts [(c)]				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the PECO mortgage indenture securing pollution control bonds and notes.
(c) Amounts owed to this financing trust are recorded as debt to financing trusts within PECO's Consolidated Balance Sheets.

BGE

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
Unsecured bonds	2.80% — 6.35%	2013-2036	$1,750	$1,850
Rate stabilization bonds	5.68% 5.82%	2016-2017	265	$ 332
Total long-term debt			2,015	2,182
Unamortized debt discount and premium, net			(4)	(4)
Long-term debt due within one year			(70)	(467)
Long-term debt			$1,941	$ 1,711
Long-term debt to financing trusts [(a)]				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ 258	$ 258

(a) Amount owed to this financing trust is recorded as debt to financing trust within BGE's Consolidated Balance Sheets.

(Dollars in millions, except per share data unless otherwise noted)

Long-term debt maturities at Exelon, Generation, ComEd, PECO and BGE in the periods 2014 through 2018 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE
2014	$ 1,428	$ 561	$ 617	$ 250	$ —
2015	1,615	555	260	—	—
2016	1,346	81	665	300	300
2017	1,396	706	425	—	265
2018	1,345	5	840	500	—
Thereafter	12,278(a)	5,644	3,093(b)	1,334(c)	1,708(d)
Total	$19,408	$ 7,552	$5,900	$2,384	$2,273

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

Non-Recourse Debt

The following are descriptions of activity with respect to certain indebtedness of Exelon's project subsidiaries that is outstanding as of December 31, 2013. The indebtedness described below is specific to certain generating facilities pledged as collateral with a net book value of approximately $1.9 billion at December 31, 2013, and all associated project financing liabilities are non-recourse to Exelon and Generation.

Continental Wind. On September 30, 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million aggregate principal amount of Continental Wind's 6.00% senior secured notes due February 28, 2033. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. In connection with this non-recourse project financing, Exelon terminated existing interest rate swaps with a total notional amount of $350 million during the third quarter of 2013, and realized a total gain of $26 million upon termination. The gain on the interest rate swaps was recorded within OCI and will reduce the effective interest rate over the life of the debt for Exelon. See Note 12—Derivative Financial Instruments for additional information on the interest rate swaps.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2013, the Continental Wind letter of credit facility had $93 million in letters of credit outstanding related to the project.

ExGen Renewables Energy I LLC. On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $300 million aggregate principal amount of EGR's LIBOR plus 425 bps non-recourse senior secured loan, due February 6, 2021. EGR indirectly owns Continental Wind LLC (Continental).

Antelope Valley Project Development Debt Agreement. The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be completed in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan are fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2013, Generation had $334 million in letters of credit outstanding related to the project The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

In connection with this agreement, Generation entered into a floating-for-fixed interest rate swap with a notional amount of $485 million to mitigate interest-rate risk associated with the financing. As Generation received additional loan advances, it subsequently entered into a series of fixed-to-floating interest rate swaps to offset portions of the original interest rate hedge. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps associated with Antelope Valley.

Sacramento PV Energy. In July, 2011, a subsidiary of Generation entered into a $41 million non-recourse project financing for a 30MW solar facility in Sacramento, California. As of December 31, 2013, $37 million was outstanding. Borrowings under the facility bear interest at a variable rate, payable quarterly, and are secured by equity interests and assets of the subsidiary. As of December 31, 2013, the subsidiary had interest rate swaps with a notional value of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $41 million facility. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Constellation Solar Horizons Financing. In September 2012, a subsidiary of Generation entered into an 18-year $38 million non-recourse variable interest note to recover capital used to build a 16 MW solar facility in Emmitsburg, Maryland. Interest is payable quarterly, and the note is secured by the equity interests and assets of the subsidiary. As of December 31, 2013, $36 million was outstanding. The subsidiary also executed interest rate swaps for a notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Secured Solar Credit Lending Agreement. In December 2013, a Generation subsidiary, Constellation Solar, LLC, paid off the remaining balance of the three-year senior secured credit facility that is designed to support the growth of solar operations in the amount of $94 million and terminated the facility. The facility was scheduled to mature in June of 2014.

Other Solar Project Financings. Generation has the following amounts outstanding under solar project loan agreements:

- $7 million fully amortizing by June 30, 2031 related to a solar project at the Denver International Airport, and
- $10 million fully amortizing by December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

Generation has a five year asset-based lending agreement associated with certain upstream gas properties that it owns. The borrowing base committed under the facility is $110 million and can increase to a total of $500 million if the assets support a higher borrowing base and Generation is able to obtain additional commitments from lenders. The facility was amended and extended through January 2019. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Exelon or Generation in the event of a default. As of December 31, 2013, $77 million was outstanding under the facility with interest payable quarterly. The facility includes a provision that requires the Generation entities owning the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2013, Generation was in compliance with this provision.

(Dollars in millions, except per share data unless otherwise noted)

14. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

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

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 744	$ 250	$ 160	$ 126	$ 9
Deferred	140	360	(27)	23	100
Investment tax credit amortization	(15)	(11)	(2)	(1)	(1)
State					
Current	181	50	50	16	—
Deferred	(6)	(34)	(29)	(2)	26
Total	$1,044	$ 615	$ 152	$ 162	$ 134

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 37	$ 104	$ (40)	$ 88	$ (97)
Deferred	701	326	237	25	101
Investment tax credit amortization	(11)	(6)	(2)	(2)	(1)
State					
Current	(25)	(12)	6	4	—
Deferred	(75)	88	38	12	4
Total	$ 627	$ 500	$ 239	$ 127	$ 7

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 1	$ 431	$ (329)	$ (71)	$ (71)
Deferred	1,200	435	544	223	130
Investment tax credit amortization	(12)	(7)	(3)	(2)	(1)
State					
Current	(3)	74	(123)	(37)	—
Deferred	271	123	161	33	17
Total	$1,457	$ 1,056	$ 250	$ 146	$ 75

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

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

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.7	1.6	3.4	1.6	4.9
Qualified nuclear decommissioning trust fund income	3.7	6.1	—	—	—
Tax exempt income	(0.2)	(0.3)	—	—	—
Health care reform legislation	0.1	—	0.7	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.9)	(3.0)	(0.6)	(0.1)	—
Production tax credits and other credits	(2.1)	(3.4)	(0.1)	—	—
Plant basis differences	(1.6)	—	(0.8)	(7.1)	(0.2)
Other	(0.1)	0.7	0.3	(0.3)	(0.9)
Effective income tax rate	37.6%	36.7%	37.9%	29.1%	39.0%

For the Year Ended December 31, 2012	Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(b)]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(3.6)	4.7	4.6	2.0	24.3
Qualified nuclear decommissioning trust fund income	5.4	9.1	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Health care reform legislation	0.1	—	0.4	—	11.6
Amortization of investment tax credit, net deferred taxes	(1.1)	(1.3)	(0.4)	(0.3)	(8.6)
Production tax credits and other credits	(2.2)	(3.7)	—	—	—
Plant basis differences	(2.4)	—	(0.3)	(11.5)	(9.0)
Merger expenses [(c)]	2.4	—	—	—	24.2
Fines and Penalties	2.6	4.4	—	—	—
Other	(1.1)	(0.5)	(0.6)	(0.2)	(13.9)
Effective income tax rate	34.9%	47.3%	38.7%	25.0%	63.6%

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE [(b)]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.4	4.5	3.6	(0.5)	5.2
Qualified nuclear decommissioning trust fund income	0.5	0.7	—	—	—
Domestic production activities deduction	(0.3)	(0.4)	—	—	—
Tax exempt income	(0.2)	(0.2)	—	—	—
Health care reform legislation	(0.2)	—	(1.0)	—	(0.5)
Amortization of investment tax credit	(0.3)	(0.3)	(0.4)	(0.3)	(0.5)
Production tax credits	(0.9)	(1.2)	—	—	—
Plant basis differences	(1.0)	—	(0.3)	(6.9)	(2.0)
Other	(0.2)	(0.7)	0.6	—	(1.7)
Effective income tax rate	36.8%	37.4%	37.5%	27.3%	35.5%

(Dollars in millions, except per share data unless otherwise noted)

(a) Exelon activity for the twelve months ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the twelve months ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012.
(b) BGE activity represents the activity for the twelve months ended December 31, 2012 and 2011.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2013 and 2012 are presented below:

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$ (11,612)	$ (3,879)	$(3,523)	$(2,573)	$(1,538)
Accrual based contracts	(214)	(214)	—	—	—
Derivatives and other financial instruments	(509)	(505)	(4)	—	—
Deferred pension and post-retirement obligation	1,489	(362)	(522)	—	(74)
Nuclear decommissioning activities	(647)	(646)	—	—	—
Deferred debt refinancing costs	173	79	(21)	(3)	(5)
Regulatory	(1,611)	—	(241)	42	(253)
Tax loss carryforward	252	76	47	11	52
Tax credit carryforward	534	534	—	—	—
Investment in CENG	(541)	(541)	—	—	—
Other, net	804	67	154	122	26
Deferred income tax liabilities (net)	$ (11,882)	$ (5,391)	$ (4,110)	$ (2,401)	$(1,792)
Unamortized investment tax credits	(490)	(454)	(22)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(12,372)	$ (5,845)	$(4,132)	$(2,404)	$(1,798)

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(10,689)	$ (3,545)	$(3,537)	$(2,437)	$ (1,553)
Accrual based contracts	(389)	(389)	—	—	—
Derivatives and other financial instruments	(392)	(479)	(4)	—	—
Deferred pension and post-retirement obligation	2,356	(439)	(598)	(11)	(12)
Nuclear decommissioning activities	(604)	(604)	—	—	—
Deferred debt refinancing costs	(537)	163	(25)	(4)	(4)
Regulatory	(1,857)	—	(116)	50	(253)
Tax loss carryforward	421	226	32	14	105
Tax credit carryforward	226	226	—	—	—
Investment in CENG	(405)	(419)	—	—	—
Other, net	701	9	83	100	67
Deferred income tax liabilities (net)	$ (11,169)	$ (5,251)	$(4,165)	$(2,288)	$ (1,650)
Unamortized investment tax credits	(251)	(216)	(24)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (11,420)	$ (5,467)	$(4,189)	$(2,291)	$(1,656)

(Dollars in millions, except per share data unless otherwise noted)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2013.

	Exelon	Generation	ComEd	PECO	BGE
Federal					
Federal net operating loss	$ 377[(a)]	$ 36	$ 139	$ —	$ 31
Deferred taxes on Federal net operating loss	132	13	49	—	11
Federal general business credits carryforward	556[(b)]	556	—	—	—
State					
State net operating losses and other credit carryforwards	3,061[(c)]	1,498[(d)]	—	167[(e)]	768[(f)]
Deferred taxes on state tax attributes (net)	161	82	—	11	41
Valuation allowance on state tax attributes	13	11	—	—	1

(a) Exelon's federal net operating loss will expire beginning in 2031
(b) Exelon's federal general business credit carryforwards will expire beginning in 2032
(c) Exelon's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2014
(d) Generation's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2014
(e) PECO's state net operating losses will expire beginning in 2031
(f) BGE's state net operating losses will expire beginning in 2026

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2013, 2012 and 2011:

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2013	$1,024	$ 876	$ 67	$ 44	$—
Increases based on tax positions related to 2013	19	19	—	—	—
Change to positions that only affect timing	649	36	257	—	—
Increases based on tax positions prior to 2013	493	493	—	—	—
Decreases based on tax positions prior to 2013	(6)	(5)	—	—	—
Decreases from expiration of statute of limitations	(4)	(4)	—	—	—
Unrecognized tax benefits at December 31, 2013	$2,175	$ 1,415	$ 324	$ 44	$—

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2012	$ 807	$ 683	$ 70	$ 48	$ 11
Merger Balance Transfer	195	183	—	—	—
Increases based on tax positions related to 2012	34	3	—	—	—
Change to positions that only affect timing	(88)	(69)	(3)	(4)	(11)
Increases based on tax positions prior to 2012	91	91	—	—	—
Decreases based on tax positions prior to 2012	(6)	(6)	—	—	—
Decreases related to settlements with taxing authorities	(2)	(2)	—	—	—
Decreases from expiration of statute of limitations	(7)	(7)	—	—	—
Unrecognized tax benefits at December 31, 2012	$1,024	$ 876	$ 67	$ 44	$—

(Dollars in millions, except per share data unless otherwise noted)

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2011	$787	$ 664	$ 72	$ 44	$ 73
Increases based on tax positions related to 2011	5	1	—	4	—
Change to positions that only affect timing	21	24	(2)	—	(62)
Decreases based on tax positions prior to 2011	(3)	(3)	—	—	—
Decrease from expiration of statute of limitations	(3)	(3)	—	—	—
Unrecognized tax benefits at December 31, 2011	$ 807	$ 683	$ 70	$ 48	$ 11

Included in Exelon's unrecognized tax benefits balance at December 31, 2013 and 2012 are approximately $1,387 million and $730 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

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

Exelon and Generation have $788 million and $768 million, respectively, of unrecognized tax benefits at December 31, 2013 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $294 million and $263 million, respectively, of unrecognized tax benefits at December 31, 2012 that, if recognized, would decrease the effective tax rate.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. Exelon is expecting to appeal this decision to the United States Court of Appeals for the Federal Circuit during 2014.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the total amount of unrecognized tax benefits will significantly decrease in the next twelve months.

Settlement of Income Tax Audits and Litigation

As of December 31, 2013, Exelon and Generation had approximately $256 million of other federal and state unrecognized tax benefits that could significantly increase or decrease within the 12 months after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate. In January 2014, certain of these unrecognized tax benefits were effectively settled and thus will result in reduced tax expense of $33 million at Generation in the first quarter of 2014.

(Dollars in millions, except per share data unless otherwise noted)

See Other Tax Matters—Like Kind Exchange section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to uncertain tax positions reflected in the Registrants' Consolidated Balance Sheets. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$(349)	$ (37)	$(174)	$ 3	$—
December 31, 2012	31	(20)	107	2	—

The following table sets forth the net interest expense, including interest related to uncertain tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations. The Registrants have not accrued any penalties with respect to uncertain tax positions. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$ 391	$ 17	$ 281	$ (1)	$—
December 31, 2012	(1)	11	(20)	(1)	9
December 31, 2011	(56)	(40)	(14)	(1)	(3)

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

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999-2012
Constellation and subsidiaries consolidated Federal income tax returns	2009-March 2012
Exelon and subsidiaries Illinois unitary income tax returns	2007-2012
Constellation combined New York corporate income tax returns	2008-2012
Various separate company Pennsylvania corporate net income tax returns	2008-2012
BGE Maryland Corporate net income tax returns	2004-2007, 2009-2012
Various other (Non-BGE) Maryland Corporate net income tax returns	2009-2012

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by

Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $87 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013, Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the $87 million penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the Internal Revenue Service issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

As of December 31, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash impacts would likely change by a material amount.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation expects to change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has estimated that adoption of the new method will result in a cash tax detriment of approximately $100 - $120 million.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd, PECO and BGE)

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd and PECO adopted the safe harbor in the Revenue Procedure for the 2011 and 2010 tax years, respectively. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its domestic production activities deduction, which are reflected in the effective income tax rate reconciliation above in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor resulted in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million, $95 million respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million related to a decreased domestic production activities deduction.

BGE adopted the safe harbor for the short period 2012 pre-merger tax year. For the year ended December 31, 2012, the adoption of the safe harbor resulted in a cash tax benefit at BGE in the amount of $27 million.

See Note 3—Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

Accounting for Gas Distribution Property Repairs (Exelon, PECO and BGE).

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and 2012 resulted in a tax benefit of $26 million at Exelon, of which $29 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. The IRS is expected to issue industry guidance in the near future. Exelon, PECO and BGE will then determine the financial statement impacts of the gas distribution repair costs accounting method changes after guidance is issued.

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants have assessed the financial impact of this guidance and do not expect it to have a material impact. Any changes in method of accounting required to conform to the final regulations will be made for the Registrant's 2014 taxable year.

2011 Illinois State Tax Rate Legislation (Exelon, Generation and ComEd)

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011—2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015—2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon re-evaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change increased Exelon's Illinois income tax provision (net of Federal taxes) by approximately $7 million, of which $12 million and $5 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed below.

Long-Term State Tax Apportionment (Exelon and Generation)

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of Exelon's and Generation's deferred state income taxes. In 2011 as a result of the 2011 Illinois State Tax Rate Legislation discussed above, Exelon and Generation re-evaluated their long-term state tax apportionment for Illinois and all other states where they have state income tax obligations, resulting in recording a deferred state tax expense during the first quarter of 2011 of $22 million and $11 million (net of Federal taxes) for Exelon and Generation, respectively. The long-term state tax apportionment also was revised in the fourth quarter of 2011 pursuant to long-term state tax apportionment policy, resulting in recording an additional deferred state tax expense of $1 million and a deferred state tax benefit of $8 million (net of Federal taxes) for Exelon and Generation, respectively.

As a result of the merger with Constellation, Exelon and Generation re-evaluated their long-term state tax apportionment in the first quarter of 2012. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the three months ended March 31, 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the three months ended March 31, 2012. The long-term state tax apportionment also was updated in the fourth quarter of 2012, resulting in the recording of a deferred state tax benefit of $3 million (net of Federal taxes) for Exelon, and a deferred state tax expense of $7 million (net of Federal taxes) for Generation. There was no change to the long-term state tax apportionment for BGE, ComEd and PECO.

The long-term state tax apportionment was revised in the fourth quarter of 2013 pursuant to its long-term state tax apportionment policy, resulting in the recording of amounts that are immaterial for Exelon and Generation, respectively.

Allocation of Tax Benefits (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2013, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $26 million and $27 million, respectively. During 2013, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd’s and BGE’s 2013 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010. During 2012, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $48 million and $9 million, respectively. During 2012, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd’s and BGE’s 2012 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010.

ComEd received a non-cash contribution to equity from Exelon in 2012 of $11, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

15. Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

(Dollars in millions, except per share data unless otherwise noted)

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2012 to December 31, 2013:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2012	$ 3,680
Accretion expense	231
Net increase due to changes in, and timing of, estimated future cash flows	833
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2012 [(a)]	4,741
Accretion expense	259
Net decrease due to changes in, and timing of, estimated future cash flows	(140)
Costs incurred to decommission retired plants	(5)
Nuclear decommissioning ARO at December 31, 2013 [(a)]	$ 4,855

(a) Includes $9 million and $10 million as the current portion of the ARO at December 31, 2013 and 2012, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2013, Generation's ARO increased by approximately $114 million. The increase is largely driven by an increase in the estimated costs to decommission the Limerick and Three Mile Island nuclear units resulting from the completion of updated decommissioning costs studies received during 2013 and an increase for accretion of the obligation. These increases in the ARO were offset by decreases to the ARO due to changes in long-term escalation rates, primarily for labor and energy costs, as well as changes in the timing of the future nominal cash flows coupled with the fact that cash flows affected by this change in timing are re-measured and discounted at current credit adjusted risk free rates (CARFRs), which have increased from the prior year. The decrease in the ARO due to the changes in, and timing of, estimated cash flows were entirely offset by decreases in Property, plant and equipment within Exelon's and Generation's Consolidated Balance Sheets.

During 2012, Generation's ARO increased by $1,061 million. The increase in the ARO was largely driven by four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which had dramatically decreased given the lower interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities, Dresden and Clinton nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in, and timing of, estimated cash flows resulted in $10 million of expense, which is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

(Dollars in millions, except per share data unless otherwise noted)

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below). Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the funds after decommissioning.

During 2012, the NDT fixed income portfolio completed its transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and middle market lending. There was no change in the equity investment strategy. At December 31, 2013, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. At December 31, 2012, approximately 47% of the funds were invested in equity securities and 53% were invested in fixed income securities.

At December 31, 2013, and 2012, Exelon and Generation had NDT fund investments totaling $8,071 million and $7,248 million, respectively.

The following table provides unrealized gains (losses) on NDT funds for 2013, 2012 and 2011:

	Exelon and Generation		
	For the Years Ended December 31,		
	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [a]	$ 406	$ 386	$ (74)
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units [b][c]	146	105	(4)

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $7 million, $73 million and $48 million of net unrealized gains related to the Zion Station pledged assets in 2013, 2012 and 2011, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO . Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. As of December 31, 2013, the NDT funds of each of the former ComEd units are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the seven former PECO nuclear units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

Refer to Note 3—Regulatory Matters and Note 25—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. On July 29, 2013, United States District Court for the Northern District of Illinois dismissed the amended complaint. On August 26, 2013, the plaintiffs filed a notice of appeal with the United States Court of Appeals for the Seventh Circuit. On January 31, 2014, the United States Court of Appeals for the Seventh Circuit dismissed the appeal.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation to the SNF following ZionSolutions completion of its contractual obligations, to transfer the SNF at Zion Station to the DOE for ultimate disposal, and to complete all remaining decommissioning activities associated with the SNF storage facility. Generation has a liability of approximately $82 million, which is included within the nuclear decommissioning ARO at December 31, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2013 and 2012:

(Dollars in millions, except per share data unless otherwise noted)

	Exelon and Generation	
	2013	2012
Carrying value of Zion Station pledged assets	$ 458	$ 614
Payable to Zion Solutions [a]	414	564
Current portion of payable to Zion Solutions [b]	109	132
Withdrawals by Zion Solutions to pay decommissioning costs [c]	498	335

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the SNF currently held in SNF pools at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by EnergySolutions or ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions has also provided a performance guarantee and entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2013 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2013 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.9% to 6.7% (as compared to a historical 5-year annual average pre-tax return of approximately 11.7%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation’s ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon’s and Generation’s cash flows and financial position may be significantly adversely affected.

On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff’s review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential “apparent violations” of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation’s status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. The January 31, 2013 letter from the NRC does not take issue with

(Dollars in millions, except per share data unless otherwise noted)

Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. In the normal course of NRC review, Generation has received a series of data requests that are unrelated to the potential apparent violations and the pre-decisional enforcement conference. Generation continues to cooperate with the NRC and provide the requested information. Generation does not have a definite date on which it will receive a response from the NRC.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation's reporting and funding of the future decommissioning of Exelon's nuclear power plants. Exelon and Generation are cooperating with the SEC and providing the requested documents.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2012 to December 31, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Non-nuclear AROs at January 1, 2012	$ 209	$ 92	$ 89	$ 28	$ 1
Net increase due to changes in, and timing of, estimated future cash flows (a)	27	18	8	1	7
Development projects	47	47	—	—	—
Accretion expense (b)	13	8	4	1	—
Merger with Constellation (c)	58	50	—	—	—
Payments	(11)	(8)	(2)	(1)	—
Non-nuclear AROs at December 31, 2012	343	207	99	29	8
Net increase due to changes in, and timing of, estimated future cash flows (a)	1	(11)	—	—	12
Development projects	2	2	—	—	—
Accretion expense (b)	18	13	4	1	—
Payments	(13)	(10)	(2)	—	(1)
Non-nuclear AROs at December 31, 2013 (d)	$ 351	$ 201	$ 101	$ 30	$ 19

(a) During the year ended December 31, 2013, Generation recorded an increase in operating and maintenance expense of $13 million. ComEd and PECO did not record any adjustments in operating and maintenance expense for the year ended December 31, 2013. During the year ended December 31, 2012, Generation recorded a reduction in operating and maintenance expense of $8 million. ComEd, PECO, and BGE did not record any reductions in operating and maintenance expense for the year ended December 31, 2012.

(b) For ComEd, PECO, and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(c) Exelon's ARO includes $8 million of BGE costs incurred prior to the closing of Exelon's merger with Constellation. Refer to Note 4—Merger and Acquisitions for additional information.
(d) Includes $2 million, $1 million, and $0 million as the current portion of the ARO at December 31, 2013 for ComEd, PECO, and BGE, respectively, which is included in other current liabilities on Exelon's and each of the respective utilities' Consolidated Balance Sheets.

16. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

As of December 31, 2013, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's benefit plans and its related assets. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2013.

	Operating Company				
Name of Plan:	Generation	ComEd	PECO	BGE	BSC
Qualified Pension Plans:					
Exelon Corporation Retirement Program	X	X	X		X
Exelon Corporation Cash Balance Pension Plan	X	X	X		X
Exelon Corporation Pension Plan for Bargaining Unit Employees	X	X			X
Exelon New England Union Employees Pension Plan	X				
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek	X	X			X
Pension Plan of Constellation Energy Group, Inc.	X			X	X
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B	X				
Non-Qualified Pension Plans:					
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan	X	X	X		X
Exelon Corporation Supplemental Management Retirement Plan	X	X	X		X
Constellation Energy Group, Inc. Senior Executive Supplemental Plan	X			X	X
Constellation Energy Group, Inc. Supplemental Pension Plan	X			X	X
Constellation Energy Group, Inc. Benefits Restoration Plan	X			X	X
Baltimore Gas & Electric Company Executive Benefit Plan	X			X	X
Baltimore Gas & Electric Company Manager Benefit Plan	X			X	X
Other Postretirement Benefit Plans:					
PECO Energy Company Retiree Medical Plan	X		X		X
Exelon Corporation Health Care Program	X	X			X
Exelon Corporation Employees' Life Insurance Plan	X	X	X		X
Constellation Energy Group, Inc. Retiree Medical Plan	X			X	X
Constellation Energy Group, Inc. Retiree Dental Plan	X			X	X
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan	X			X	X
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan	X				
Exelon New England Union Post-Employment Medical Savings Account Plan	X				

(Dollars in millions, except per share data unless otherwise noted)

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated Other Comprehensive Income (AOCI) and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2013, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased by approximately $93 million. During the second quarter of 2013, Exelon received the updated valuation for the legacy Constellation pension and other postretirement obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $23 million and a decrease to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax) and regulatory assets increased by approximately $14 million.

The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Change in benefit obligation:				
Net benefit obligation at beginning of year	$16,800	$13,538	$ 4,820	$ 4,062
Service cost	317	280	162	156
Interest cost	650	698	194	205
Plan participants' contributions	—	—	34	34
Actuarial loss (gain)	(1,363)	1,520	(551)	313
Plan amendments	1	—	15	(103)
Acquisitions/divestitures	—	1,880	—	362
Curtailments	—	(10)	—	(8)
Settlements [(a)]	(69)	(169)	—	—
Contractual termination benefits	—	15	—	6
Gross benefits paid	(877)	(952)	(223)	(219)
Federal subsidy on benefits paid	—	—	—	12
Net benefit obligation at end of year	$15,459	$16,800	$ 4,451	$ 4,820

(Dollars in millions, except per share data unless otherwise noted)

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Change in plan assets:				
Fair value of net plan assets at beginning of year	$13,357	$ 11,302	$ 2,135	$ 1,797
Actual return on plan assets	821	1,484	209	197
Employer contributions	339	149	83	325
Plan participants' contributions	—	—	34	34
Benefits paid (b)	(877)	(952)	(223)	(218)
Acquisitions/divestitures	—	1,543	—	—
Settlements (a)	(69)	(169)	—	—
Fair value of net plan assets at end of year	$13,571	$13,357	$ 2,238	$ 2,135

(a) Represents cash settlements only.
(b) Exelon's other postretirement benefits paid for the year ended December 31, 2012 are net of $1.3 million of reinsurance proceeds received from the Department of Health and Human Services as part of the Early Retiree Reinsurance Program pursuant to the Affordable Care Act of 2010. In 2013, the Program was no longer accepting applications for reimbursement.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Other current liabilities	$ 12	$ 15	$ 23	$ 23
Pension obligations	1,876	3,428	—	—
Non-pension postretirement benefit obligations	—	—	2,190	2,662
Unfunded status (net benefit obligation less net plan assets)	$1,888	$3,443	$ 2,213	$ 2,685

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2013	2012
Projected benefit obligation	$ 15,452	$ 16,800
Fair value of net plan assets	13,564	13,357

	ABO in excess of plan assets	
	2013	2012
Projected benefit obligation	$ 15,452	$ 16,796
Accumulated benefit obligation	14,552	15,657
Fair value of net plan assets	13,564	13,353

(Dollars in millions, except per share data unless otherwise noted)

On a PBO basis, the plans were funded at 88% at December 31, 2013 compared to 80% at December 31, 2012. On an ABO basis, the plans were funded at 93% at December 31, 2013 compared to 85% at December 31, 2012. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table presents the components of Exelon's net periodic benefit costs for the years ended December 31, 2013, 2012 and 2011. The table reflects an increase in 2012 and a reduction in 2011 of net periodic postretirement benefit costs of approximately $(17) million and $28 million, respectively, related to a Federal subsidy provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), discussed further below.

The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. Certain plans were remeasured during the year using a discount rate of 4.21%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Certain plans were remeasured during the year using a discount rate of 4.66%. Certain other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Components of net periodic benefit cost:						
Service cost	$ 317	$ 280	$ 212	$ 162	$ 156	$142
Interest cost	650	698	649	194	205	207
Expected return on assets	(1,015)	(988)	(939)	(132)	(115)	(111)
Amortization of:						
Transition obligation	—	—	—	—	11	9
Prior service cost (credit)	14	15	14	(19)	(17)	(38)
Actuarial loss	562	450	331	83	81	66
Curtailment benefits	—	—	—	—	(7)	—
Settlement charges	9	31	—	—	—	—
Contractual termination benefits [(a)]	—	14	—	—	6	—
Net periodic benefit cost	$ 537	$ 500	$ 267	$ 288	$320	$275

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the contractual termination benefit charge in 2012.

Through Exelon's postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. In December 2011, the Company decided that beginning in 2013, it will no longer elect to take the direct Part D subsidy. Beginning in 2013, eligible employees are offered an Employee Group Waiver Plan, a Medicare Part D Plan, with a supplemental "wrap" that closely matches the current prescription drug plan design. See the *Health*

(Dollars in millions, except per share data unless otherwise noted)

Care Reform Legislation section below for further discussion regarding the income tax treatment of Federal subsidies of prescription drug benefits.

The effect of the subsidy on the components of net periodic postretirement benefit cost for the years ended December 31, 2013, 2012 and 2011 included in the consolidated financial statements was as follows:

	2013	2012	2011
Amortization of the actuarial experience loss	$—	$(17)	$ 3
Reduction in current period service cost	—	—	9
Reduction in interest cost on the APBO	—	—	16
Total effect of subsidy on net periodic postretirement benefit cost	$—	$(17)	$28

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2013, 2012 and 2011 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$(1,169)	$1,693	$ 744	$(628)	$ 304	$ 74
Amortization of actuarial gain (loss)	(562)	(450)	(331)	(83)	(81)	(66)
Current year prior service (credit) cost	—	1	—	15	(109)	—
Amortization of prior service (cost) credit	(14)	(15)	(14)	19	17	38
Current year transition (asset) obligation	—	—	—	—	1	—
Amortization of transition asset (obligation)	—	—	—	—	(11)	(9)
Curtailments	—	(10)	—	—	(1)	—
Settlements	(8)	(31)	—	—	—	—
Total recognized in AOCI and regulatory assets (liabilities) [(a)]	$(1,753)	$1,188	$ 399	$(677)	$ 120	$ 37

(a) Of the $1,753 million gain related to pension benefits, $1,071 million and $682 million were recognized in AOCI and regulatory assets, respectively, during 2013. Of the $677 million gain related to other postretirement benefits, $352 million and $325 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2013. Of the $1,188 million loss related to pension benefits, $283 million and $904 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $120 million loss related to other postretirement benefits, $39 million and $81 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $399 million loss related to pension benefits, $181 million and $218 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $37 million loss related to other postretirement benefits, $13 million and $24 million were recognized in AOCI and regulatory assets, respectively, during 2011.

(Dollars in millions, except per share data unless otherwise noted)

The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2013 and 2012, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Prior service cost (credit)	$ 62	$ 76	$ (73)	$ (107)
Actuarial loss	6,192	7,931	474	1,185
Total[(a)]	$6,254	$8,007	$ 401	$ 1,078

(a) Of the $6,254 million related to pension benefits, $3,523 million and $2,731 million are included in AOCI and regulatory assets, respectively, at December 31, 2013. Of the $401 million related to other postretirement benefits, $161 million and $240 million are included in AOCI and regulatory assets (liabilities), respectively, at December 31, 2013. Of the $8,007 million related to pension benefits, $4,594 million and $3,413 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $1,078 million related to other postretirement benefits, $514 million and $564 million are included in AOCI and regulatory assets, respectively, at December 31, 2012.

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2013 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2014. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2014 and actual claims activity as of December 31, 2013. The valuation is expected to be completed in the first quarter of 2014 for legacy Exelon plans and in the second quarter of 2014 for legacy Constellation plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 14	$ (16)
Actuarial loss	427	32
Total[(a)]	$ 441	$ 16

(a) Of the $441 million related to pension benefits at December 31, 2013, $232 million and $209 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively. Of the $16 million related to other postretirement benefits at December 31, 2013, $7 million and $9 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors.

(Dollars in millions, except per share data unless otherwise noted)

Expected Rate of Return. In selecting the expected rate of return on plan assets, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

The following assumptions were used to determine the benefit obligations for all of the plans at December 31, 2013, 2012 and 2011. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.80%	3.92%	4.74%	4.90%	4.00%	4.80%
Rate of compensation increase	(a)	(b)	3.75%	(a)	(b)	3.75%
Mortality table	IRS required mortality table for 2014 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2014 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.00% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017

(a) 3.25% for 2014-2018 and 3.75% thereafter.
(b) 3.25% for 2013-2017 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2013, 2012 and 2011:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	3.92%(a)	4.74%(b)	5.26%	4.00%(a)	4.80%(b)	5.30%
Expected return on plan assets	7.50%(c)	7.50%(c)	8.00%(c)	6.45%(c)	6.68%(c)	7.08%(c)
Rate of compensation increase	(d)	3.75%	3.75%	(d)	3.75%	3.75%
Mortality table	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	7.00% decreasing to ultimate trend of 5.00% in 2015

(Dollars in millions, except per share data unless otherwise noted)

(a) The discount rates above represent the initial discount rates used to establish Exelon's pension and other postretirement benefits costs for the year ended December 31, 2013. Certain of the benefit plans were remeasured during the year using discount rates of 4.21% and 4.66% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2013 reflect the impact of these remeasurements.
(b) The discount rates above represent the initial discounts rates used to establish Exelon's pension and other postretirement benefits costs for 2012. Certain of the benefit plans were remeasured during the year due to the Constellation merger, plan settlement and curtailment events, and plan changes using discount rates of 3.71% and 3.72% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2012 reflect the impact of these remeasurements.
(c) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(d) 3.25% for 2013-2017 and 3.75% thereafter.

Assumed health care cost trend rates have a significant effect on the costs reported for the other postretirement benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2013 total service and interest cost components	$ 90
on postretirement benefit obligation at December 31, 2013	858
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2013 total service and interest cost components	(62)
on postretirement benefit obligation at December 31, 2013	(607)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Generation, ComEd, PECO and BGE recorded charges of $24 million, $11 million, $9 million and $3 million, respectively. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon has made a change in the manner in which it will receive prescription drug subsidies beginning in 2013.

Additionally, the Health Care Reform Acts also include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

(Dollars in millions, except per share data unless otherwise noted)

Contributions

The following table provides contributions made by Generation, ComEd, PECO, BGE and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011 [(c)]	2013 [(a)]	2012 [(a)]	2011 [(a)]
Generation	$ 119	$ 48	$ 954	$ 30	$ 135	$ 121
ComEd	118	25	873	4	119	108
PECO	11	13	110	20	33	28
BGE [(b)]	—	—	—	24	12	—
BSC	91	63	157	5	24	20
Exelon	$339	$149	$2,094	$ 83	$ 323	$ 277

(a) The Registrants present the cash contributions above net of Federal subsidy payments received on each of their respective Consolidated Statements of Cash Flows. Exelon, Generation, ComEd, PECO, and BGE received Federal subsidy payments of $10 million, $5 million, $4 million, $1 million and $2 million, respectively, in 2012, and $11 million, $5 million, $4 million, $1 million and $3 million, respectively, in 2011. Effective January 1, 2013, Exelon is no longer receiving this subsidy.

(b) BGE's pension benefit contributions for 2012 and 2011 exclude $0 million and $54 million, respectively, of pension contributions made by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. BGE's other postretirement benefit payments for 2012 and 2011 exclude $4 million and $13 million, respectively, of other postretirement benefit payments made by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. These pre-merger contributions are not included in Exelon's financial statements but are reflected in BGE's financial statements.

(c) The increase in 2011 pension contributions was related to Exelon's $2.1 billion contribution to its pension plans as a result of accelerated cash benefits associated with the Tax Relief Act of 2010.

Exelon plans to contribute $264 million to its qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $118 million, $119 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon plans to make non-qualified pension plan benefit payments of $12 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $5 million, $1 million, $0 million and $1 million, respectively. Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, for Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million, which approximates service cost, or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower minimum pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others were applied in 2013. The estimated impacts of the law are reflected in the projected pension contributions.

Unlike the qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). In 2014, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $430 million in 2014, of which Generation, ComEd, PECO, and BGE expect to contribute $168 million, $197 million, $19 million, and $17 million, respectively.

(Dollars in millions, except per share data unless otherwise noted)

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2013 were:

	Pension Benefits	Other Postretirement Benefits
2014	$ 929	$ 204
2015	851	210
2016	873	219
2017	902	228
2018	1,015	238
2019 through 2023	5,257	1,383
Total estimated future benefit payments through 2023	$9,827	$ 2,482

Allocation to Exelon Subsidiaries

Generation, ComEd, PECO, and BGE account for their participation in Exelon's pension and other postretirement benefit plans by applying multiemployer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. Exelon allocates the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each participating unit. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Pension and postretirement benefit contributions are allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. For legacy CEG plans, components of pension and other postretirement benefit costs and contributions are allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below were included in capital expenditures and operating and maintenance expense for the years ended December 31, 2013, 2012 and 2011, respectively, for Generation's, ComEd's, PECO's, BSC's and BGE's allocated portion of the pension and postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC [(a)]	BGE [(b)(c)]	Exelon
2013	$ 347	$ 309	$ 43	$ 71	$ 55	$ 825
2012	341	282	50	99	60	820
2011	249	213	32	48	51	542

(Dollars in millions, except per share data unless otherwise noted)

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of December 31, 2012, ComEd and BGE each reported a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.
(b) The amounts included in capital and operating and maintenance expense for the years ended December 31, 2012 and 2011 include $12 million and $51 million, respectively, in costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's capital expenditures and operating and maintenance expense for the years ended December 31, 2012 and 2011.
(c) BGE's pension and other postretirement benefit costs for the year ended December 31, 2012 include a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of December 31, 2012.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2013 and 2012 asset allocations were as follows:

Pension Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2013	2012
Equity securities	31%	35%	35%
Fixed income securities	38%	37	40
Alternative investments [(a)]	31%	28	25
Total		100%	100%

Other Postretirement Benefit Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2013	2012
Equity securities	41%	45%	46%
Fixed income securities	39%	37	40
Alternative investments [(a)]	20%	18	14
Total		100%	100%

(Dollars in millions, except per share data unless otherwise noted)

(a) Alternative investments include private equity, hedge funds and real estate.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2013. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2013, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2013 and 2012:

At December 31, 2013 [(a)]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Equity securities:				
Individually held	3,090	—	2	3,092
Commingled funds	—	1,167	—	1,167
Mutual funds	270	—	—	270
Equity securities subtotal	3,360	1,167	2	4,529
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	908	9	—	917
Debt securities issued by states of the United States and by political subdivisions of the states	—	88	—	88
Foreign debt securities	—	205	—	205
Corporate debt securities	—	2,927	41	2,968
Federal agency mortgage-backed securities	—	90	—	90
Non-Federal agency mortgage-backed securities	—	26	—	26
Commingled funds	—	558	—	558
Mutual funds	5	315	—	320
Derivative instruments [(b)]:				
Assets	—	7	—	7
Liabilities	—	(134)	—	(134)
Fixed income securities subtotal	913	4,091	41	5,045
Private equity	—	—	806	806
Hedge funds	—	1,266	1,039	2,305
Real estate:				
Individually held	264	—	—	264
Commingled funds	—	2	—	2
Real estate funds	—	—	582	582
Real estate subtotal	264	2	582	848
Pension plan assets subtotal	4,537	6,526	2,470	13,533

(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2013 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	51	—	—	51
Equity securities:				
Individually held	286	—	—	286
Commingled funds	—	515	—	515
Mutual funds	164	—	—	164
Equity securities subtotal	450	515	—	965
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	17	1	—	18
Debt securities issued by states of the United States and by political subdivisions of the states	—	149	—	149
Foreign debt securities	—	2	—	2
Corporate debt securities	—	50	—	50
Federal agency mortgage-backed securities	—	45	—	45
Non-Federal agency mortgage-backed securities	—	7	—	7
Commingled funds	—	218	—	218
Mutual funds	305	—	—	305
Fixed income securities subtotal	322	472	—	794
Private equity	—	—	2	2
Hedge funds	—	295	4	299
Real estate:				
Individually held	8	—	—	8
Real estate funds	—	5	109	114
Real estate subtotal	8	5	109	122
Other postretirement benefit plan assets subtotal	831	1,287	115	2,233
Total pension and other postretirement benefit plan assets [c]	$5,368	$7,813	$2,585	$15,766

(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2012 [(a)]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$ —	$ —	$ 1
Equity securities:				
Individually held	2,562	—	—	2,562
Commingled funds	—	1,111	—	1,111
Mutual funds	323	—	—	323
Equity securities subtotal	2,885	1,111	—	3,996
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,037	—	—	1,037
Debt securities issued by states of the United States and by political subdivisions of the states	—	108	—	108
Foreign debt securities	—	252	—	252
Corporate debt securities	—	3,330	—	3,330
Federal agency mortgage-backed securities	—	117	—	117
Non-Federal agency mortgage-backed securities	—	28	—	28
Commingled funds	—	274	—	274
Mutual funds	4	291	—	295
Derivative instruments [(b)]:				
Assets	—	9	—	9
Liabilities	—	(21)	—	(21)
Fixed income securities subtotal	1,041	4,388	—	5,429
Private equity	—	—	754	754
Hedge funds	—	1,080	1,235	2,315
Real estate:				
Individually held	280	—	—	280
Commingled funds	—	75	—	75
Real estate funds	—	—	426	426
Real estate subtotal	280	75	426	781
Pension plan assets subtotal	4,207	6,654	2,415	13,276

(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2012 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	44	—	—	44
Equity securities:				
Individually held	198	—	—	198
Commingled funds	—	530	—	530
Mutual funds	230	—	—	230
Equity securities subtotal	428	530	—	958
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	18	—	—	18
Debt securities issued by states of the United States and by political subdivisions of the states	—	125	—	125
Foreign debt securities	—	3	—	3
Corporate debt securities	—	50	—	50
Federal agency mortgage-backed securities	—	52	—	52
Non-Federal agency mortgage-backed securities	—	6	—	6
Commingled funds	—	271	—	271
Mutual funds	295	2	—	297
Fixed income securities subtotal	313	509	—	822
Private equity	—	—	1	1
Hedge funds	—	188	12	200
Real estate:				
Individually held	7	—	—	7
Commingled funds	—	2	—	2
Real estate funds	—	6	95	101
Real estate subtotal	7	8	95	110
Other postretirement benefit plan assets subtotal	792	1,235	108	2,135
Total pension and other postretirement benefit plan assets [c]	$4,999	$7,889	$2,523	$15,411

(a) See Note 11—Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $2,651 million and $2,498 million at December 31, 2013 and 2012, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) Excludes net assets of $43 million and $81 million at December 31, 2013 and 2012, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.

(Dollars in millions, except per share data unless otherwise noted)

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2013 and 2012:

	Hedge funds	Private equity	Real estate	Debt securities	Preferred stock	Total
Pension Assets						
Balance as of January 1, 2013	$1,235	$ 754	$426	$ —	$ —	$2,415
Actual return on plan assets:						
Relating to assets still held at the reporting date	143	86	63	—	—	292
Relating to assets sold during the period	3	—	(4)	—	—	(1)
Purchases, sales and settlements:						
Purchases	360	123	226	41	2	752
Sales	(76)	—	(91)	—	—	(167)
Settlements [(a)]	(3)	(157)	(38)	—	—	(198)
Transfers into (out of) Level 3 [(b)]	(623)	—	—	—	—	(623)
Balance as of December 31, 2013	$1,039	$ 806	$582	$ 41	$ 2	$2,470
Other Postretirement Benefits						
Balance as of January 1, 2013	$ 12	$ 1	$ 95	$ —	$ —	$ 108
Actual return on plan assets:						
Relating to assets still held at the reporting date	1	—	11	—	—	12
Relating to assets sold during the period	—	—	—	—	—	—
Purchases, sales and settlements:						
Purchases	—	1	3	—	—	4
Sales	(1)	—	—	—	—	(1)
Settlements [(a)]	(4)	—	—	—	—	(4)
Transfers into (out of) Level 3 [(b)]	(4)	—	—	—	—	(4)
Balance as of December 31, 2013	$ 4	$ 2	$ 109	$ —	$ —	$ 115

(Dollars in millions, except per share data unless otherwise noted)

	Hedge funds	Private equity	Real estate	Debt securities	Preferred stock	Total
Pension Assets						
Balance as of January 1, 2012	$1,525	$ 672	$229	$ —	$ —	$2,426
Actual return on plan assets:						
Relating to assets still held at the reporting date	138	55	24	—	—	217
Purchases, sales and settlements:						
Purchases	447	108	134	—	—	689
Sales	(6)	—	—	—	—	(6)
Settlements [(a)]	(4)	(128)	(28)	—	—	(160)
Transfers into (out of) Level 3 [(c)(d)(e)]	(865)	47	67	—	—	(751)
Balance as of December 31, 2012	$1,235	$ 754	$426	$ —	$ —	$ 2,415
Other Postretirement Benefits						
Balance as of January 1, 2012	$ 157	$ 1	$ 7	$ —	$ —	$ 165
Actual return on plan assets:						
Relating to assets still held at the reporting date	11	—	3	—	—	14
Purchases, sales and settlements:						
Purchases	32	—	91	—	—	123
Sales	—	—	—	—	—	—
Settlements [(a)]	—	—	(1)	—	—	(1)
Transfers into (out of) Level 3 [(c)(d)(e)]	(188)	—	(5)	—	—	(193)
Balance as of December 31, 2012	$ 12	$ 1	$ 95	$ —	$ —	$ 108

(a) Represents cash settlements only.
(b) As of December 31, 2012, hedge fund investments that contained redemption restrictions limiting Exelon's ability to redeem the investments within a reasonable period of time were classified as Level 3 investments. As of December 31, 2013, restrictions for certain investments no longer applied, therefore allowing redemption within a reasonable period of time from the measurement date at NAV. As such, these hedge fund investments are reflected as transfers out of Level 3 to Level 2 of $627 million in 2013.
(c) In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's pension plan assets resulting in transfers into Level 3 of $141 million.
(d) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.
(e) In 2012, the liquidity terms of a certain real estate investment changed to allow redemption within a reasonable period of time from the redemption date which led to a transfer out of Level 3 to Level 2 of $5 million.

Valuation Techniques Used to Determine Fair Value

Cash equivalents. Investments with maturities of three months or less when purchased, including certain short—term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equity securities. With respect to individually held equity securities, including investments in U.S. and international securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually are primarily traded on exchanges that contain only actively traded securities, due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The fair values of fixed income securities, excluding U.S. Treasury securities and privately placed fixed income securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Fixed income commingled funds and mutual funds, including short-term investment funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Private equity. Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

(Dollars in millions, except per share data unless otherwise noted)

Hedge funds. Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate. For Exelon's investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit Exelon's ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized as Level 3.

Real estate. Real estate investment trusts valued daily based on quoted prices in active markets are categorized as Level 1. Real estate commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Since these funds are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Other real estate funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, these real estate funds have been categorized as Level 3.

Defined Contribution Savings Plan (Exelon, Generation, ComEd, PECO and BGE)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO	BGE [(a)]	BSC [(b)]
2013	$ 85	$ 40	$ 22	$ 8	$ 8	$ 7
2012	67	30	19	7	7	5
2011	78	40	22	9	7	7

(a) BGE's matching contributions for the years ended December 31, 2012 and 2011 include $1 million and $7 million of costs, respectively, incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These costs are not included in Exelon's matching contributions for the years ended December 31, 2012 and 2011.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, or BGE amounts above.

17. Severance (Exelon, Generation, ComEd, PECO and BGE)

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

(Dollars in millions, except per share data unless otherwise noted)

Merger-Related Severance

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

The amount of severance expense associated with the post-merger integration recognized for the year ended December 31, 2013 for Exelon and Generation was $6 million and $6 million, respectively. For Generation, $5 million represents amounts billed by BSC through intercompany allocations. There was no severance expense associated with post-merger integration recognized for the year ended December 31, 2013 for ComEd, PECO and BGE. Estimated costs to be incurred after December 31, 2013 are not material.

For the year ended December 31, 2012, the Registrants recorded the following severance benefit costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for those costs that were capitalized as regulatory assets related to ComEd and BGE:

Year Ended December 31, 2012 Severance Benefits [(a)]	Exelon [(b)]	Generation	ComEd [(b)]	PECO	BGE [(b)]
Severance charges	$ 124	$ 80	$ 14	$ 7	$ 17
Stock compensation	7	4	1	—	1
Other charges	7	4	1	—	1
Total severance benefits	$ 138	$ 88	$ 16	$ 7	$ 19

(a) The amounts above include $46 million at Generation, $14 million at ComEd, $7 million at PECO, and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2012.
(b) Exelon, ComEd and BGE established regulatory assets of $35 million, $16 million and $19 million, respectively, for severance benefits costs for the year ended December 31, 2012. The majority of these costs are expected to be recovered over a five-year period.

(Dollars in millions, except per share data unless otherwise noted)

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2011	$ —	$ —	$ —	$—	$—
Severance charges [(a)]	124	38	2	—	11
Stock compensation	7	2	—	—	—
Other charges [(b)]	7	2	—	—	1
Payments	(27)	(9)	(1)	—	(1)
Balance at December 31, 2012	$ 111	$ 33	$ 1	$—	$ 11
Severance charges	5	1	—	—	—
Stock compensation	1	—	—	—	—
Payments	(64)	(24)	(1)	—	(5)
Balance at December 31, 2013	$ 53	$ 10	$ —	$—	$ 6

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for under Exelon's ongoing severance plan. One-time termination benefits were not material for the years ended December 31, 2012 and December 31, 2013.
(b) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business, which were not directly related to the merger with Constellation. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2013, 2012, and 2011, the Registrants recorded the following severance costs associated with these ongoing severance benefits within operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Severance Benefits [(a)]	Exelon	Generation	ComEd	PECO	BGE
Severance charges—2013	$ 18	$ 16	$ 2	$—	$—
Severance charges—2012	19	14	2	1	3
Severance charges—2011	5	5	—	—	4

(a) The amounts above for Generation include $2 million, $0 million, and $1 million for amounts billed by BSC through intercompany allocations for the years ended December 31, 2013, December 31, 2012, and December 31, 2011, respectively. Amounts billed by BSC to ComEd, PECO and BGE were not material.

The severance liability balances associated with these ongoing severance benefits as of December 31, 2013 and 2012 are not material.

(Dollars in millions, except per share data unless otherwise noted)

18. Preferred and Preference Securities (Exelon, ComEd, PECO and BGE)

At December 31, 2013 and 2012, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Preferred and Preference Securities of Subsidiaries

At December 31, 2013 and 2012, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2012, PECO cumulative preferred securities, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred securities have full voting rights, including the right to cumulate votes in the election of directors. On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series was issued. The redemption premium is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon.

		December 31,			
	Redemption Price [a]	2013	2012	2013	2012
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68 (Series D)	$ 104.00	—	150,000	$ —	$ 15
$4.40 (Series C)	112.50	—	274,720	—	27
$4.30 (Series B)	102.00	—	150,000	—	15
$3.80 (Series A)	106.00	—	300,000	—	30
Total preferred securities		—	874,720	$ —	$ 87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

At December 31, 2013 and 2012, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

(Dollars in millions, except per share data unless otherwise noted)

	Redemption Price [(a)]	December 31, 2013 Shares Outstanding	December 31, 2012 Shares Outstanding	December 31, 2013 Dollar Amount	December 31, 2012 Dollar Amount
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.00	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.00	500,000	500,000	50	50
6.70%, 1993 Series	100.34	400,000	400,000	40	40
6.99%, 1995 Series	100.70	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$ 190	$ 190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

19. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

The following table presents common stock authorized and outstanding as of December 31, 2013 and 2012:

	Par Value	Shares Authorized	December 31, 2013 Shares Outstanding	December 31, 2012 Shares Outstanding
Common Stock				
Exelon	no par value	2,000,000,000	857,290,484	854,781,389
ComEd	$12.50	250,000,000	127,016,896	127,016,761
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	175,000,000	1,000	1,000

ComEd had 73,709 and 74,182 warrants outstanding to purchase ComEd common stock at December 31, 2013 and 2012, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2013 and 2012, 24,570 and 24,727 shares of common stock, respectively, were reserved for the conversion of warrants.

Share Repurchases

Share Repurchase Programs. In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. In 2008, Exelon management decided to defer indefinitely any share repurchases. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2013. During 2013, 2012 and 2011, Exelon had no common stock repurchases.

(Dollars in millions, except per share data unless otherwise noted)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the years ended December 31, 2013, 2012 and 2011, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon's Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of performance shares and restricted stock. The performance share awards granted in 2013 will cliff vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year cliff vesting performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011:

Components of Stock-Based Compensation Expense	Year Ended December 31,		
	2013	2012	2011
Performance share awards	$ 48	$ 46	$ 26
Restricted stock units	61	50	31
Stock options	3	15	8
Other stock-based awards	6	4	4
Total stock-based compensation expense included in operating and maintenance expense	118	115	69
Income tax benefit	(44)	(44)	(27)
Total after-tax stock-based compensation expense	$ 74	$ 71	$ 42

The following table presents stock-based compensation expense (pre-tax) for the years ended December 31, 2013, 2012 and 2011:

Subsidiaries	Year Ended December 31,		
	2013	2012 [(a)]	2011 [(d)]
Generation	$ 48	$ 42	$ 31
ComEd	9	11	5
PECO	5	5	5
BGE	6	5	6
BSC [(b)]	50	52	28
Total [(c)]	$118	$ 115	$ 69

(a) BGE's stock-based compensation expense (pre-tax) for December 31, 2012 excludes $2 million of cost incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the year ended December 31, 2012 shown in the tables titled Components of Stock-Based Compensation Expense and Subsidiaries above.

(Dollars in millions, except per share data unless otherwise noted)

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.
(c) The stock-based compensation expense (pre-tax) for December 31, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd does not reflect the impact of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not considered stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.
(d) The total stock-based compensation expense (pre-tax) for December 31, 2011 of $69 million does not include the $6 million expense for BGE as those costs were incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2013, 2012 and 2011.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Realized tax benefit when exercised/distributed:			
Stock options	$—	$ 3	$ 2
Restricted stock units	11	11	8
Performance share awards	11	7	7
Stock deferral plan	1	—	1
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	$—	$ 2	$ 1

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for senior vice presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

(Dollars in millions, except per share data unless otherwise noted)

Historically, Exelon has granted most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2012 and 2011 were not significant.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the years ended 2012 and 2011:

	Year Ended December 31, 2012	Year Ended December 31, 2011
Dividend yield	5.28%	4.84%
Expected volatility	23.20%	24.40%
Risk-free interest rate	1.30%	2.65%
Expected life (years)	6.25	6.25
Weighted average grant date fair value (per share)	$ 4.18	$ 6.22

The assumptions above relate to Exelon stock options granted during the periods presented and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended 2012.

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity for the year ended December 31, 2013:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2012	21,903,781	$ 45.91		
Options reinstated	751,122	38.60		
Options exercised	(670,957)	28.02		
Options forfeited	(54,743)	39.36		
Options expired	(893,758)	49.08		
Balance of shares outstanding at December 31, 2013	21,035,445	$ 46.07	4.72	$ 10
Exercisable at December 31, 2013 (a)	20,188,327	$ 46.31	4.58	$ 10

(a) Includes stock options issued to retirement eligible employees.

(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Intrinsic value (a)	$ 4	$ 19	$ 5
Cash received for exercise price	19	47	13

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2013:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2012 (a)	1,960,665	$ 40.56
Vested	(1,058,804)	40.89
Forfeited	(54,743)	39.36
Nonvested at December 31, 2013 (a)	847,118	$ 40.22

(a) Excludes 1,348,913 and 2,647,536 of stock options issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.

At December 31, 2013, $2 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.6 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2013:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2012 (a)	2,029,161	$ 42.12
Granted	2,828,187	31.06
Vested	(842,439)	42.90
Forfeited	(108,199)	36.37
Undistributed vested awards (b)	(520,013)	32.62
Nonvested at December 31, 2013 (a)	3,386,697	$ 34.10

(a) Excludes 931,628 and 686,121 of restricted stock units issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2013.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2013, 2012 and 2011 was $31.06, $39.94 and $43.33, respectively. At December 31, 2013 and 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $77 million and $58 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2013, 2012 and 2011, Exelon settled restricted stock units with fair value totaling $28 million, $25 million and $19 million, respectively. At December 31, 2013, $64 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.5 years.

Performance Share Awards

Performance share awards are granted under the LTIP. The 2013 and 2012 performance share awards are being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company's performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can decrease the award by up to 50% or increase the award by up to 10% for SVPs and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

(Dollars in millions, except per share data unless otherwise noted)

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2013:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2012 (a)	1,312,734	$ 40.08
Granted	2,629,171	31.55
Vested	(612,624)	40.13
Forfeited	(24,451)	32.17
Undistributed vested awards (b)	(1,290,640)	34.28
Nonvested at December 31, 2013 (a)	2,014,190	$ 32.74

(a) Excludes 1,411,824 and 204,643 of performance share awards issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2013.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2013, 2012 and 2011 was $31.55, $39.71, and $43.52, respectively. During the years ended December 31, 2013, 2012 and 2011, Exelon settled performance shares with a fair value totaling $26 million, $23 million and $22 million, respectively, of which $12 million, $3 million and $10 million was paid in cash, respectively. As of December 31, 2013, $34 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.7 years.

(Dollars in millions, except per share data unless otherwise noted)

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31, 2013	December 31, 2012
Current liabilities [(a)]	$ 13	$ 7
Deferred credits and other liabilities [(b)]	24	11
Common stock	32	35
Total	$69	$ 53

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

20. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31, 2013	2012	2011
Net income attributable to common shareholders	$1,719	$1,160	$2,495
Weighted average common shares outstanding—basic	856	816	663
Assumed exercise and/or distributions of stock-based awards	4	3	2
Weighted average common shares outstanding—diluted	860	819	665

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 20 million in 2013, 14 million in 2012 and 9 million in 2011.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of earnings per share for Exelon for the year ending December 31, 2013. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

(Dollars in millions, except per share data unless otherwise noted)

21. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following table presents changes in accumulated other comprehensive income (loss) (AOCI) by component for the year ended December 31, 2013:

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon (a)						
Beginning balance	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	29	2	669	(10)	101	791
Amounts reclassified from AOCI (b)	(277)	—	208	—	5	(64)
Net current-period OCI	(248)	2	877	(10)	106	727
Ending balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$ (2,040)
Generation (a)						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	$ 513
OCI before reclassifications	15	2	—	(10)	102	109
Amounts reclassified from AOCI (b)	(413)	—	—	—	5	(408)
Net current-period OCI	(398)	2	—	(10)	107	(299)
Ending balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
PECO (a)						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI (b)	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next table for details about these reclassifications.

(Dollars in millions, except per share data unless otherwise noted)

ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net Income during the year ended December 31, 2013. The following table presents amounts reclassified out of AOCI to Net Income for Exelon and Generation during the year ended December 31, 2013:

Details about AOCI components	Items reclassified out of AOCI [(a)] Exelon	Items reclassified out of AOCI [(a)] Generation	Affected line item in the statement where Net Income is presented
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 464	$ 683	Operating revenues
Other cash flow hedges	(3)	—	Interest expense
	461	683	Total before tax
	(184)	(270)	Tax expense
	$ 277	$ 413	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (2)	$ —	(b)
Actuarial losses	(339)	—	(b)
Deferred compensation unit plan	(1)	—	(c)
	(342)	—	Total before tax
	134	—	Tax benefit
	$ (208)	$ —	Net of tax
Equity investments			
Capital activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications	$ 64	$ 408	Net of Tax

(a) Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see note 16 for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

22. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2013, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2013, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $13.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.4 billion.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. NEIL declared a distribution for 2013, of which Generation's portion was $18.5 million. The distribution was recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. No distributions were declared in 2011 or 2012. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, as of December 31, 2013, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $287 million.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. As of December 31, 2013, Generation's current limit for this coverage is $2.1 billion. For property limits in excess of the first $1.25 billion of that limit, Generation participates in an $850 million single limit blanket policy shared by all the Generation operating nuclear sites and the Salem and Hope Creek nuclear sites. This blanket limit is not subject to automatic reinstatement in the event of a loss. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Generation could be assessed up to $229 million per year for losses incurred at any plant insured by the insurance company (the retrospective premium obligation). In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. The Terrorism Risk Insurance Act expires on December 31, 2014.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at an insured nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation's maximum share of any assessment is $58 million per year (the retrospective premium obligation). Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007, as described above.

NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing. On the same date, as ordered by the court, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero, subject to any further judicial decision. The DOE's submitted proposal becomes effective after the 90-days of continuous session of the Congress unless there is Congressional action contrary to the DOE proposal. However, if the court grants the petition for rehearing, the proposal to eliminate the fee (and the review period) will be held in suspense until after the court rules. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devised a new strategy for long-term SNF management. A Blue Ribbon Commission (BRC) on America's Nuclear

Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Clinton, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreement, Generation has received cash reimbursements for costs incurred through April 30, 2013, totaling approximately $712 million ($601 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2013, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $71 million, which is recorded within Accounts receivable, other. Of this amount, $18 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

CENG entered into settlement agreements with the DOE during 2011 and 2012 to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel related to the Ginna, Calvert Cliffs and Nine Mile Point nuclear power plants. At December 31, 2012, Generation had approximately $22 million recorded as a receivable from CENG with respect to costs incurred by Constellation prior to the formation of the CENG joint venture for the Nine Mile Point and Calvert Cliffs nuclear power plants. CENG received the funds for the Nine Mile Point and Calvert Cliffs settlement from the DOE in January 2013 and February 2013, respectively, and remitted the $22 million to Generation.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2013, the unfunded SNF liability for the one-time fee with interest was $1,021 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2013, was 0.051%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. The outstanding one-time fee obligations for the Oyster Creek and TMI units remain with the former owners. Clinton has no outstanding obligation. See Note 11—Fair Value of Assets and Liabilities for additional information.

(Dollars in millions, except per share data unless otherwise noted)

Energy Commitments

Generation's customer facing activities include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. In addition to physical contracts, Generation uses financial contracts for economic hedging purposes and, to a lesser extent, as part of proprietary trading activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. Generation provides for delivery of its energy to these customers through firm transmission.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. Generation discloses in the table below commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 5—Investment in Constellation Energy Nuclear Group, LLC and Note 25—Related Party Transactions for more details on this arrangement.

At December 31, 2013, Generation's short- and long-term commitments, relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$1,378
2015	367	110	13	—	490
2016	284	76	2	—	362
2017	223	25	2	—	250
2018	112	3	2	—	117
Thereafter	414	3	32	—	449
Total	$ 1,812	$ 334	$ 76	$ 824	$3,046

(Dollars in millions, except per share data unless otherwise noted)

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA and spot market purchases. See Note 3—Regulatory Matters for further information.

Since 2009, PECO has entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements for 2011 through 2016. See Note 3—Regulatory Matters for further information regarding the DSP Programs.

ComEd is subject to requirements established by the Illinois Settlement Legislation and the Energy Infrastructure Modernization Act related to the use of alternative energy resources. PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirement. BGE has entered into contracts with curtailment services providers in accordance with the March 2009 MDPSC order. See Note 3—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of December 31, 2013 are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
ComEd							
Electric supply procurement [(a)]	$ 736	$323	$136	$137	$140	$—	$ —
Renewable energy and RECs [(b)]	1,589	72	74	76	77	83	1,207
PECO							
Electric supply procurement [(c)]	681	590	91	—	—	—	—
AECs [(d)]	14	2	2	2	2	2	4
BGE							
Electric supply procurement [(e)]	1,256	783	400	73	—	—	—
Curtailment services [(f)]	132	45	40	34	13	—	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 3—Regulatory Matters for additional information.
(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3—Regulatory Matters for additional information.

(Dollars in millions, except per share data unless otherwise noted)

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2014 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 3—Regulatory Matters for additional information.
(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 3—Regulatory Matters for additional information.
(e) BGE entered into various contracts for the procurement of electricity beginning 2013 through 2016. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3—Regulatory Matters for additional information.
(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 3—Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation. PECO and BGE have commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2013, these net commitments were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Generation	$8,490	$1,212	$1,256	$1,040	$1,044	$763	$ 3,175
PECO	507	179	112	98	37	15	66
BGE	609	129	59	57	57	51	256

Other Purchase Obligations

The Registrants' other purchase obligations as of December 31, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Exelon	$262	$ 61	$ 34	$32	$31	$ 26	$ 78
Generation	504	170	131	45	42	30	86
ComEd (a)	122	88	5	5	5	5	14
PECO (a)	40	30	1	1	1	1	6
BGE (a)	53	44	2	5	2	—	—

(a) Purchase obligations include commitments related to smart meter installation. See Note 3 - Regulatory Matters for additional information.

(Dollars in millions, except per share data unless otherwise noted)

Commercial Commitments

Exelon's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) (a)	$ 1,520	$1,217	$298	$—	$ 5	$—	$ —
Surety bonds (b)	339	301	2	6	4	1	25
Performance guarantees (c)	1,107	350	—	—	—	—	757
Energy marketing contract guarantees (d)	3,161	3,161	—	—	—	—	—
Lease guarantees (e)	44	—	—	—	—	—	44
Nuclear insurance premiums (f)	3,529	—	—	—	—	—	3,529
Total commercial commitments	$9,700	$5,029	$ 300	$ 6	$ 9	$ 1	$ 4,355

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Guarantees issued to ensure performance under specific contracts, including $211 million issued on behalf of CENG nuclear generating facilities for credit support, $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $3 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $463 million at December 31, 2013, which represents the total amount Exelon could be required to fund based on December 31, 2013 market prices.
(e) Lease guarantees—Guarantees issued to ensure payments on building leases.
(f) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Generation's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) (a)	$1,477	$ 1,174	$298	$—	$ 5	$—	$ —
Performance guarantees (b)	357	343	—	—	—	—	14
Energy marketing contract guarantees (c)	832	832	—	—	—	—	—
Nuclear insurance premiums (d)	3,529	—	—	—	—	—	3,529
Total commercial commitments	$6,195	$2,349	$298	$—	$ 5	$—	$ 3,543

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Performance guarantees—Guarantees issued to ensure performance under specific contracts including $211 million issued on behalf of CENG nuclear generating facilities for credit support.

(Dollars in millions, except per share data unless otherwise noted)

(c) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $749 million of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Generation's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.2 billion at December 31, 2013, which represents the total amount Generation could be required to fund based on December 31, 2013 market prices.
(d) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

ComEd's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 19	$ 19	$—	$—	$—	$—	$ —
Surety bonds [(b)]	9	9	—	—	—	—	—
Performance guarantees [(c)]	200	—	—	—	—	—	200
Total commercial commitments	$228	$ 28	$—	$—	$—	$—	$ 200

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

PECO's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 22	$ 22	$—	$—	$—	$—	$ —
Surety bonds [(b)]	3	3	—	—	—	—	—
Performance guarantees [(c)]	178	—	—	—	—	—	178
Total commercial commitments	$203	$ 25	$—	$—	$—	$—	$ 178

(a) Letters of credit (non-debt)—PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

(Dollars in millions, except per share data unless otherwise noted)

BGE's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 1	$ 1	$—	$—	$—	$—	$ —
Surety bonds [(b)]	9	9	—	—	—	—	—
Performance guarantees [(c)]	250	—	—	—	—	—	250
Total commercial commitments	$260	$ 10	$—	$—	$—	$—	$ 250

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bond—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantee—Reflects full and unconditional guarantee of Trust Preferred Securities of BGE Capital Trust which is an unconsolidated VIE of BGE.

Construction Commitments

Generation has committed to the construction of the Antelope Valley solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013 and an expectation of full commercial operation in the first half of 2014. Generation's estimated remaining commitment for the project is $110 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $50 million and achievement of commercial operations is expected in 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120 MW of new natural gas-fired generation to satisfy certain merger commitments. The estimated remaining commitment under the contract is $80 million and achievement of commercial operation is expected in 2015. See 4—Merger and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

On December 27, 2013, Generated executed a Turbine Supply Agreement for construction of the 32.5MW Fourmile Wind project in western Maryland. The estimated remaining commitment under the contract is $26 million and achievement of commercial operations is expected in 2014. See 4—Merger and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

Refer to Note 3—Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan, and BGE's comprehensive smart grid initiative.

Constellation Merger Commitments

Exelon's commercial and construction commitments shown above do not include the merger commitments made to the State of Maryland in conjunction with the Constellation merger. See Note 4—Merger and Acquisitions for additional information on the mergers commitments.

(Dollars in millions, except per share data unless otherwise noted)

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2013 were:

	Exelon	Generation	ComEd (b)	PECO (b)	BGE (b)(c)
2014	$ 103	$ 49	$ 13	$ 13	$ 12
2015	91	50	11	3	11
2016	89	49	11	3	9
2017	82	48	7	3	8
2018	63	40	2	3	7
Remaining years	398	336	3	—	14
Total minimum future lease payments	$826(a)	$ 572(a)	$ 47	$ 25	$ 61

(a) Excludes Generation's PPAs and other capacity contracts that are accounted for as contingent operating lease payments.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO and BGE have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd's, PECO's, and BGE's annual obligation for these arrangements, included in each of the years 2014—2018, was $1 million, $3 million, and $1 million respectively.
(c) Includes all future lease payments on a 99 year real estate lease that expires in 2105.

The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation (a)	ComEd	PECO	BGE
2013	$ 806	$ 744	$ 15	$ 21	$ 11
2012	930	872	18	27	12
2011	711	659	18	28	15

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $694 million, $801 million and $630 million during 2013, 2012 and 2011, respectively.

For information regarding capital lease obligations, see Note 13—Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under performance guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation was required to perform in the event that TII did not pay any obligation covered by the guarantee that was not otherwise subject to a dispute resolution process. Portions of the exposures covered by this guarantee expired in 2008, and the remaining guarantee expired in the third quarter of 2013. Generation was not required to make payments under the guarantee, and therefore, has no further obligation related to this guarantee as of December 31, 2013.

Environmental Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property currently or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For many of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2020.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. During the third quarter of 2013, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by less than $1 million and $6 million, respectively. BGE assessed its currently and formerly owned gas manufacturing and purification sites quarterly in 2013 and determined that a loss was not probable at ten of its sites as of December 31, 2013. As discussed above, the remediation costs at two of BGE's MGP sites are not considered material. Furthermore, an estimate of a range of possible loss, if any, related to BGE's gas purification site under investigation cannot be determined as of December 31, 2013 given that the site is in the early stages of investigation and the extent of contamination is currently unknown. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets.

(Dollars in millions, except per share data unless otherwise noted)

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

As of December 31, 2013 and 2012, the Registrants have accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2013	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 338	$ 273
Generation	56	—
ComEd	234	229
PECO	47	44
BGE	1	—

December 31, 2012	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 351	$ 298
Generation	42	—
ComEd	261	254
PECO	47	44
BGE	1	—

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of

Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called "non-use" benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On June 27, 2013, the U.S. EPA agreed to amend the court approved Settlement Agreement to extend the deadline to issue a final rule until November 4, 2013 and on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until January 14, 2014 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have again agreed to extend the date for issuance of the final rule until April 17, 2014. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities, as well as CENG's, without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation and CENG.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the Merger, Constellation recorded in its Consolidated Balance Sheets total liabilities of approximately $30 million to comply with the consent decree with an additional $3 million recognized through purchase accounting. During third quarter of 2013, Generation increased its reserve by $2 million based on an update of future estimated remediation costs. The remaining liability as of December 31, 2013, is approximately $14 million. In addition, a private party asserted claims relating to groundwater contamination. Generation has reached an agreement in principle to resolve these claims. The amount of the settlement is not material to the financial condition of Generation.

Alleged Conemaugh Clean Streams Act Violation. The PA DEP has alleged that GenOn Northeast Management Company (GenOn), the operator of Conemaugh Generating Station, violated the Pennsylvania Clean Streams Law. GenOn reached agreement with PA DEP on a proposed Consent Decree that was approved by the Commonwealth Court of Pennsylvania on December 4, 2012. Under the Consent Decree, GenOn is obligated to pay a civil penalty of $0.5 million, of which Generation's responsibility was approximately $0.2 million. Generation made the final payment in January 2014 and is complying with the Consent Decree.

Air Quality

Cross-State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. The Court's order was appealed to the U.S. Supreme Court, where oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

Under the CSAPR, generation units were to receive allowances based on historic heat input and intrastate, and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of December 31, 2013, Generation had $56 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime during 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of December 31, 2013, Exelon had a $698 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairment recorded in the second quarter of 2013, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than that of the U.S. EPA's current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in U.S. EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 U.S. EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states' counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant SO_2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third-party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

During the second quarter of 2013, Exelon filed proofs of claim of $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. Further, Exelon filed an environmental claim with an unspecified amount that listed the indemnifications that were in place pre-Petition Date and other factors associated with the remediation. As of December 31, 2013, Exelon has not recorded a receivable for the filed proofs of claim because recovery of any amount cannot be assured at this point in the bankruptcy. Exelon will not record claim recoveries unless and until they are realized.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation's bankruptcy. On January 17, 2014, Midwest Generation filed a plan supplement to its bankruptcy filing that included a request to reject the sale agreement, including the environmental indemnity. ComEd and Generation have reviewed available public information as to potential environmental exposures regarding the Midwest Generation station sites. Midwest Generation publicly disclosed in its quarter ending September 30, 2013 Form 10-Q that (i) it has accrued a probable amount of approximately $8 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of December 31, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. In addition to the sale agreement, Midwest Generation also requested to reject this supplemental agreement in the January 17, 2014 plan supplement to its bankruptcy filing. Exelon and Generation had previously expected Midwest Generation or its successor would remain responsible for asbestos personal injury claims filed post-Petition Date, and as a result had not recorded a liability for such amounts. Exelon and Generation now believe that the rejection of the 1999 sale and supplemental agreements is probable, and as a result, Generation has increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million. The increase in the reserve was estimated using actuarial assumptions and analyses available to Generation. Generation's exposure could differ to the extent new information is received or made available. Midwest Generation publicly disclosed in its quarter ending September 30, 2013 Form 10-Q that they had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. If the agreements are rejected, Exelon and

Generation may be entitled to damages associated with the agreement terminations. These amounts are considered to be contingent gains and would not be recognized until realized.

On October 18, 2013, NRG Energy entered into an agreement to buy EME's portfolio of generation subject to regulatory approvals. Exelon continues to monitor all aspects of the bankruptcy; the proposed purchase by NRG has not impacted any accounting conclusions as of December 31, 2013.

In May 2010, the United States and State of Illinois initiated a lawsuit against Midwest Generation, ComEd and EME alleging Clean Air Act violations relating to the modification and/or operation of six (coal) electric generation plants in Northern Illinois, which ComEd sold to Midwest Generation/EME in 1999. The government parties sought injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertained to ComEd. On March 16, 2011, the District Court granted ComEd's motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. On July 8, 2013, the Circuit Court affirmed the District Court's dismissal of the complaint against ComEd. On September 19, 2013, the Circuit Court denied the petition for a rehearing filed by the governmental parties. The government parties did not seek United States Supreme Court review of the Seventh Circuit's decision. The deadline for seeking such review was in December 2013. In light of the Circuit Court decision resolving this matter in favor of ComEd, no reserve has been established.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted into 2014. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty

Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants") and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs estimated range of costs noted above. Based on Exelon's preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC(CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $6 million, which has been fully reserved as of December 31, 2013.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA's "Tailpipe Rule" for cars and light duty trucks, the endangerment finding for GHG's from stationary sources, and the Tailoring Rule. On October 15, 2013 the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

On June 25, 2013, President Obama announced "The President's Climate Action Plan," a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration's plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(b) of the Clean Air Act is to focus on establishing carbon regulations for new fossil-fuel power plants. This rulemaking was proposed on September 20, 2013 and is to be finalized "in a timely fashion." In the proposed rule U.S.EPA sets separate standards for fossil-fuel fired utility boilers and natural gas fired stationary combustion turbines.

The second rulemaking, under Section 111(d) of the Clean Air Act is to focus on modified, reconstructed and existing fossil power plants. The rulemaking is to be proposed no later than June 1, 2014, be finalized no later than June 1, 2015, and require that states submit to U.S. EPA their implementation plans no later than June 30, 2016. In developing this rulemaking, U.S. EPA is directed to consider a number of factors, including options to reduce costs, options to ensure the continued use of a range of energy sources and technologies, options that are consistent with reliable and affordable power, and options that allow for the use of market-based instruments, performance standards and other regulatory flexibilities.

To the extent that the final Section 111(d) rule results in emission reductions from fossil fuel fired plants, and thereby imposes some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results could benefit.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE).

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2013 and 2012, Generation had reserved approximately $90 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2013, approximately $19 million of this amount related to 224 open claims presented to Generation, while the remaining $71 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not apply to preclude such employee from suing his or her employer in court. The Supreme

Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of December 31, 2013. Increased claims activity resulting from this ruling could have a material adverse impact on Exelon, Generation's and PECO's future results of operations and cash flows.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 486 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation (Exelon and Generation).

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation's power trading activities in and around the ISO-NY from September 2007 through December 2008. Prior to the merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay, and has paid, a $135 million civil penalty and $110 million in disgorgement.

During the year ended December 31, 2012, Generation recorded expense of $195 million in operating and maintenance expense with the remaining $50 million recorded as a Constellation pre-acquisition contingency. See Note 4—Merger and Acquisitions for additional information on the merger.

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. However, the ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General's request for the ICC to open an investigation into ComEd's infrastructure and storm hardening investments.

Following the ICC's June 26, 2013 denial of ComEd's request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC's interpretation of Section 16-125 of the Illinois Public Utilities Act. ComEd cannot predict the outcome of appeals.

As a result of the ICC's June 5, 2013 ruling, ComEd established a liability, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in Cook County on behalf of a single individual and a presumptive class that would include all customers in ComEd's service territory who were enrolled by the Company in ComEd's Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act ("TCPA") by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $500 to $1,500 per text. However, ComEd is preparing a motion to dismiss this class action complaint and will vigorously contest the allegations of this suit. The ultimate outcome of this proceeding is uncertain, and an amount, if any, which might be asserted, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows. As a result, ComEd has not established a reserve for this complaint as of December 31, 2013.

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation's June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions sought, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On May 9, 2013, the federal court in Maryland preliminarily approved the settlement of Constellation's 2008 Securities Class Action for a payment of $4 million, which will be paid by Constellation's insurer. Notice of the settlement was provided to class members in June 2013 and the court approved the final settlement on November 4, 2013. This settlement will resolve all of Constellation's litigation arising from the 2008 Securities Class Action lawsuit.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO and BGE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed;

(2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE pays dividends on its common stock after its board of directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE is currently reviewing the merits of this claim. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

(Dollars in millions, except per share data unless otherwise noted)

General (Exelon, Generation, ComEd, PECO and BGE).

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

Income Taxes

See Note 14—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

23. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 449	$ 79	$ 241	$129	$ 82
Property	302	205	24	14	112
Payroll	159	89	27	13	15
Other	185	16	7	2	4
Total taxes other than income	$1,095	$ 389	$ 299	$ 158	$213

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 463	$ 82	$ 239	$ 141	$ 75
Property	227	189	22	13	111
Payroll	131	78	26	12	18
Other	198	20	8	(4)	4
Total taxes other than income	$1,019	$ 369	$ 295	$162	$208

(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$443	$ 27	$ 243	$173	$ 79
Property	177	146	22	9	107
Payroll	123	71	25	13	17
Other	42	20	6	10	4
Total taxes other than income	$ 785	$ 264	$ 296	$205	$207

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's and BGE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues, respectively. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [(a)]—					
Regulatory agreement units	$ 256	$ 256	$ —	$—	$—
Non-regulatory agreement units	77	77	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	406	406	—	—	—
Non-regulatory agreement units	146	146	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities [(b)]	(546)	(546)	—	—	—
Total decommissioning-related activities	346	346	—	—	—
Investment income	8	(1)	—	(1)	9[(c)]
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	24	4	—	—	—
AFUDC—Equity	22	—	11	4	7
Other	45	19	15	3	1
Other, net	$ 473	$ 368	$ 26	$ 6	$ 17

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [(a)]—					
Regulatory agreement units	$ 189	$ 189	$ —	$—	$—
Non-regulatory agreement Units	102	102	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	386	386	—	—	—
Non-regulatory agreement units	105	105	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	73	73	—	—	—
Regulatory offset to decommissioning trust fund-related activities [(b)]	(530)	(530)	—	—	—
Total decommissioning-related activities	325	325	—	—	—

(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Investment income	20	3	1	2	11(c)
Long-term lease income	29	—	—	—	—
Interest income related to uncertain income tax positions	15	2	20	—	—
AFUDC—Equity	17	—	6	4	10
Credit facility termination fees	(85)	(85)	—	—	—
Other	25	(6)	12	2	2
Other, net	$346	$ 239	$ 39	$ 8	$ 23

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds (a)—					
Regulatory agreement units	$ 177	$ 177	$ —	$—	$—
Non-regulatory agreement units	45	45	—	—	—
Net unrealized losses on decommissioning trust funds—					
Regulatory agreement units	(74)	(74)	—	—	—
Non-regulatory agreement units	(4)	(4)	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	48	48	—	—	—
Regulatory offset to decommissioning trust fund-related activities (b)	(130)	(130)	—	—	—
Total decommissioning-related activities	62	62	—	—	—
Investment income	10	1	1	3	13(c)
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	53	31	14	1	—
AFUDC—Equity	17	—	8	9	15
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—	—
Other	(3)	(8)	6	1	(2)
Other, net	$ 203	$ 122	$ 29	$ 14	$ 26

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3—Regulatory Matters for additional information regarding the rate stabilization deferral.

(Dollars in millions, except per share data unless otherwise noted)

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,893	$ 813	$ 545	$219	$264
Regulatory assets	212	—	119	9	84
Amortization of intangible assets, net	48	43	5	—	—
Amortization of energy contract assets and liabilities [(a)]	430	507	—	—	—
Nuclear fuel [(a)]	921	921	—	—	—
ARO accretion [(b)]	275	275	—	—	—
Total depreciation, amortization, accretion and depletion	$3,779	$ 2,559	$ 669	$228	$348

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,712	$ 733	$ 525	$207	$245
Regulatory assets	129	—	80	10	53
Amortization of intangible assets, net	40	35	5	—	—
Amortization of energy contract assets and liabilities [(a)]	1,110	1,110	—	—	—
Nuclear fuel [(a)]	848	848	—	—	—
ARO accretion [(b)]	240	240	—	—	—
Total depreciation, amortization, accretion and depletion	$4,079	$ 2,966	$ 610	$217	$298

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$1,284	$ 570	$ 502	$191	$224
Regulatory assets	63	—	52	11	50
Nuclear fuel [(a)]	755	755	—	—	—
ARO accretion [(b)]	214	214	—	—	—
Total depreciation, amortization and accretion	$2,316	$ 1,539	$ 554	$202	$274

(a) Included in revenues or fuel expense, or operating revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 866	$ 291	$ 283	$ 95	$130
Income taxes (net of refunds)	112	(18)	33	70	42
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 825	$ 345	$ 308	$ 43	$ 56
Earnings from equity method investments	(10)	(10)	—	—	—
Provision for uncollectible accounts	101	10	(15)	61	44
Provision for excess and obsolete inventory	9	9	—	—	—
Stock-based compensation costs	120	—	—	—	—
Other decommissioning-related activity [(a)]	(169)	(169)	—	—	—
Energy-related options [(b)]	104	104	—	—	—
Amortization of regulatory asset related to debt costs	12	—	9	3	—
Amortization of rate stabilization deferral	66	—	—	—	66
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Discrete impacts from EIMA [(c)]	(271)	—	(271)	—	—
Amortization of debt costs	18	10	1	2	2
Impairment of investments in direct financing leases [(e)]	14	—	—	—	—
Impairment charges [(f)]	149	149	—	—	—
Other	(58)	—	(4)	(1)	(15)
Total other non-cash operating activities	$ 876	$ 414	$ 28	$108	$153
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 12	$ —	$ (35)	$ 9	$ 38
Other regulatory assets and liabilities	(64)	—	(43)	(16)	(71)
Other current assets	(165)	(151)	(2)	13	(8)
Other noncurrent assets and liabilities	322	15	268[(g)]	(12)	(23)
Total changes in other assets and liabilities	$ 105	$ (136)	$ 188	$ (6)	$ (64)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$(128)	$ (128)	$ —	$—	$ 4
Change in capital expenditures not paid	(38)	(107)[(h)]	(8)	13	(48)
Consolidated VIE dividend to non-controlling interest	63	63	—	—	—
Indemnification of like-kind exchange position [(i)]	—	—	176	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.
(d) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 3—Regulatory Matters for more information.
(e) Relates to an other than temporary decline in the estimated residual value of one of Exelon's direct financing leases. See Note 8—Impairment of Long-Lived Assets for more information.
(f) Relates to the cancellation of uprate projects and write down of certain wind projects at Generation. See Note 8— Impairment of Long-Lived Assets for more information.

(Dollars in millions, except per share data unless otherwise noted)

(g) Relates primarily to interest payable related to like-kind exchange tax position. See Note 14—Income Taxes for discussion of the like-kind exchange tax position.
(h) Includes $55 million of changes in capital expenditures not paid between December 31, 2013 and 2012 related to Antelope Valley.
(i) See Note 14—Income Taxes for discussion of the like-kind exchange tax position.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 761	$ 286	$ 288	$ 113	$ 136
Income taxes (net of refunds)	(171)	175	(42)	(64)	(112)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 820	$ 341	$ 282	$ 50	$ 57
Loss in equity method investments	91	91	—	—	—
Provision for uncollectible accounts	164	22	42	60	44
Provision for excess and obsolete inventory	6	6	1	—	—
Stock-based compensation costs	94	—	—	—	—
Other decommissioning-related activity [(a)]	(145)	(145)	—	—	—
Energy-related options [(b)]	160	160	—	—	—
Amortization of regulatory asset related to debt costs	18	—	13	3	2
Amortization of rate stabilization deferral	57	—	—	—	67
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Merger-related commitments [(d)]	141	32	—	—	27
Severance costs	99	34	—	—	—
Discrete impacts from EIMA [(c)]	(96)	—	(96)	—	—
Amortization of debt costs	19	11	5	3	2
Other	(11)	19	5	9	(6)
Total other non-cash operating activities	$1,383	$ 537	$ 252	$125	$ 193
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 71	$ —	$ 28	$ 20	$ 26
Other regulatory assets and liabilities	(404)	—	(68)	18	(112)
Other current assets	213	(30)	(7)	(12)	(7)
Other noncurrent assets and liabilities	(248)	(98)	(95)	(10)	8
Total changes in other assets and liabilities	$ (368)	$ (128)	$(142)	$ 16	$ (85)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 781	$ 781	$ 2	$—	$—
Change in capital expenditures not paid	160	103(e)	15	26	(4)
Merger with Constellation, common stock issued	7,365	5,264	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.

(Dollars in millions, except per share data unless otherwise noted)

(d) Relates to the integration costs to achieve distribution synergies related to the merger transaction. See Note 4—Mergers and Acquisitions for more information on merger-related commitments.
(e) Includes $127 million of changes in capital expenditures not paid between December 31, 2012 and 2011 related to Antelope Valley.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 649	$ 158	$ 296	$128	$ 122
Income taxes (net of refunds)	(457)	347	(676)	(65)	(54)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 542	$ 249	$ 213	$ 32	$ 51
Provision for uncollectible accounts	121	—	57	64	44
Stock-based compensation costs	67	—	—	—	—
Other decommissioning-related activity [(a)]	16	16	—	—	—
Energy-related options [(b)]	137	137	—	—	—
Amortization of regulatory asset related to debt costs	21	—	18	3	2
Amortization of rate stabilization deferral	—	—	—	—	57
Deferral of storm costs	—	—	—	—	(16)
Uncollectible accounts recovery, net	14	—	14	—	—
Discrete impacts from 2010 Rate Case Order [(c)]	(32)	—	(32)	—	—
Bargain purchase gain related to Wolf Hollow Acquisition	(36)	(36)	—	—	—
Discrete impacts from EIMA [(d)]	(82)	—	(82)	—	—
Other	2	55	(4)	1	(9)
Total other non-cash operating activities	$ 770	$ 421	$ 184	$ 100	$ 129
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (45)	$ —	$ (49)	$ 4	$ (52)
Other regulatory assets and liabilities	—	—	44	26	10
Other current assets	(101)	(23)	(14)	(12)	(88)
Other noncurrent assets and liabilities	122	(34)	64	(4)	(31)
Total changes in other assets and liabilities	$ (24)	$ (57)	$ 45	$ 14	$(161)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 186	$ 186	$ —	$—	$—
Change in capital expenditures not paid	96	125[(e)]	7	(35)	(7)

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan. See Note 3—Regulatory Matters for more information.
(d) Includes the establishment of a regulatory asset, pursuant to EIMA, for the 2011 annual reconciliation in ComEd's distribution formula rate tariff and the deferral of costs associated with significant 2011 storms, partially offset by an accrual to fund a new Science and Technology Innovation Trust. See Note 3—Regulatory Matters for more information.
(e) Includes $120 million of changes in capital expenditures not paid between December 31, 2011 and 2010 related to Antelope Valley.

(Dollars in millions, except per share data unless otherwise noted)

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the year ended December 31, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $74 million, $27 million and $47 million, respectively, and reimbursements of $95 million, $37 million and $58 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the year ended December 31, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $103 million, $56 million and $47 million, respectively, and reimbursements of $113 million, $66 million and $47 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 3—Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2013 and 2012.

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [(a)]	$ 22	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	32	32	—	—	—
Conemaugh Fuels, LLC	21	21	—	—	—
CENG	1,925	1,925	—	—	—
Safe Harbor	285	285	—	—	—
Malacha	8	8	—	—	—
Other investments	31	31	—	—	—
Total equity method investments	2,324	2,302	6	8	8
Other investments:					
Net investment in direct financing leases	698	0	—	—	—
Employee benefit trusts and investments [(b)]	90	23	5	23	5
Total investments	$ 3,112	$ 2,325	$ 11	$ 31	$ 13

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [(a)]	$ 22	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	38	38	—	—	—
Conemaugh Fuels, LLC	26	26	—	—	—
CENG	1,849	1,849	—	—	—
Safe Harbor	293	293	—	—	—
Malacha	8	8	—	—	—
Other investments	34	33	—	—	—
Total equity method investments	2,270	2,247	6	8	8
Other investments:					
Net investment in direct financing leases	685	—	—	—	—
Employee benefit trusts and investments [(b)]	100	22	8	22	5
Total investments	$ 3,055	$ 2,269	$ 14	$ 30	$ 13

(Dollars in millions, except per share data unless otherwise noted)

(a) Includes investments in financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments in affiliates on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.

The following tables provide additional information about liabilities of the Registrants at December 31, 2013 and 2012.

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [(a)]	$ 683	$ 337	$ 135	$ 47	$ 55
Taxes accrued	315	212	62	24	16
Interest accrued	234	72	95	32	29
Severance accrued	66	31	3	1	4
Other accrued expenses	335[(b)]	324[(b)]	12	2	7
Total accrued expenses	$1,633	$ 976	$ 307	$106	$ 111

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [(a)]	$ 708	$ 371	$ 125	$ 45	$ 38
Taxes accrued	353	247	61	3	22
Interest accrued	232	60	96	32	37
Severance accrued	91	42	4	1	5
Other accrued expenses	412[(b)]	396[(b)]	9	1	—
Total accrued expenses	$1,796	$ 1,116	$ 295	$ 82	$102

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $228 million and $327 million for amounts accrued related to Antelope Valley as of December 31, 2013 and December 31, 2012, respectively.

24. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. Generation's expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

The CODMs for ComEd, PECO, and BGE evaluate performance and allocate resources for their respective companies based on net income and return on equity for ComEd, PECO, and BGE each as single integrated businesses.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

(Dollars in millions, except per share data unless otherwise noted)

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2013, 2012 and 2011 is as follows:

	Generation [(a)]	ComEd	PECO	BGE [(b)]	Other [(c)]	Intersegment Eliminations	Exelon
Operating revenues [(d)]:							
2013	$ 15,630	$ 4,464	$ 3,100	$ 3,065	$ 1,241	$ (2,612)	$ 24,888
2012	14,437	5,443	3,186	2,091	1,396	(3,064)	23,489
2011	10,447	6,056	3,720	—	830	(1,990)	19,063
Intersegment revenues [(e)]:							
2013	$ 1,367	$ 3	$ 1	$ 13	$ 1,237	$ (2,607)	$ 14
2012	1,660	2	3	9	1,381	(3,049)	6
2011	1,161	2	5	—	831	(1,990)	9
Depreciation and amortization							
2013	$ 856	$ 669	$ 228	$ 348	$ 52	$ —	$ 2,153
2012	768	610	217	238	48	—	1,881
2011	570	554	202	—	21	—	1,347
Operating expenses [(d)]:							
2013	$ 13,976	$ 3,510	$ 2,434	$ 2,616	$ 1,324	$ (2,618)	$ 21,242
2012	13,226	4,557	2,563	2,053	1,662	(3,043)	21,018
2011	7,571	5,074	3,065	—	863	(1,990)	14,583
Equity in earnings (losses) of unconsolidated affiliates							
2013	$ 10	$ —	$ —	$ —	$ —	$ —	$ 10
2012	(91)	—	—	—	—	—	(91)
2011	(1)	—	—	—	—	—	(1)
Interest expense, net:							
2013	$ 357	$ 579	$ 115	$ 122	$ 183	$ —	$ 1,356
2012	301	307	123	111	86	—	928
2011	170	345	134	—	77	—	726
Income (loss) before income taxes:							
2013	$ 1,675	$ 401	$ 557	$ 344	$ (191)	$ (13)	$ 2,773
2012	1,058	618	508	(54)	(325)	(7)	1,798
2011	2,827	666	535	—	(59)	(13)	3,956
Income taxes:							
2013	$ 615	$ 152	$ 162	$ 134	$ (20)	$ 1	$ 1,044
2012	500	239	127	(23)	(215)	(1)	627
2011	1,056	250	146	—	9	(4)	1,457
Net income (loss):							
2013	$ 1,060	$ 249	$ 395	$ 210	$ (171)	$ (14)	$ 1,729
2012	558	379	381	(31)	(110)	(6)	1,171
2011	1,771	416	389	—	(68)	(9)	2,499
Capital expenditures:							
2013	$ 2,752	$ 1,433	$ 537	$ 587	$ 86	$ —	$ 5,395
2012	3,554	1,246	422	500	67	—	5,789
2011	2,491	1,028	481	—	42	—	4,042
Total assets:							
2013	$ 41,232	$ 24,118	$ 9,617	$ 7,861	$ 8,317	$ (11,221)	$ 79,924
2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

(Dollars in millions, except per share data unless otherwise noted)

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the year ended December 31, 2013 include revenue from sales to PECO of $405 and sales to BGE of $455 million in the Mid-Atlantic region, and sales to ComEd of $506 in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the year ended December 31, 2012 include revenue from sales to PECO of $543 and sales to BGE of $322 million in the Mid-Atlantic region, and sales to ComEd of $795 in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the year ended 2011 intersegment revenues for Generation include revenue from sales to PECO of $508 million in the Mid-Atlantic region, and sales to ComEd of $653 million in the Midwest region.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through December 31, 2013.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the years ended December 31, 2013, 2012 and 2011, utility taxes of $79 million, $82 million and $27 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2013, 2012 and 2011, utility taxes of $241 million, $239 million and $243 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2013, 2012 and 2011, utility taxes of $129 million, $141 million and $173 million, respectively, are included in revenues and expenses for PECO. For the year ended December 31, 2013 and for the period of March 12, 2012 through December 31, 2012, utility taxes of $82 million and $59 million are included in revenues and expenses for BGE, respectively.
(e) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

Generation total revenues:

	2013			2012			2011		
	Revenues from external customers [(a)]	Intersegment revenues	Total Revenues	Revenues from external customers [(a)]	Intersegment revenues	Total Revenues	Revenues from external customers [(a)]	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 5,182	$ 22	$ 5,204	$ 5,082	$ (44)	$ 5,038	$ 4,052	$ —	$ 4,052
Midwest	4,280	(10)	4,270	4,824	24	4,848	5,445	—	5,445
New England	1,245	(8)	1,237	1,048	45	1,093	11	—	11
New York	735	(21)	714	582	(25)	557	—	—	—
ERCOT	1,222	(6)	1,216	1,365	2	1,367	575	—	575
Other Regions [(b)]	946	22	968	755	78	833	201	—	201
Total Revenues for Reportable Segments	$ 13,610	$ (1)	$13,609	$ 13,656	$ 80	$13,736	$ 10,284	$ —	$10,284
Other [(c)]	2,020	1	2,021	781	(80)	701	163	—	163
Total Generation Consolidated Operating Revenues	$ 15,630	$ —	$15,630	$ 14,437	$ —	$14,437	$ 10,447	$ —	$10,447

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $767 million and $1,505 million for the years ended December 31, 2013 and 2012, respectively, and elimination of intersegment revenues.

(Dollars in millions, except per share data unless otherwise noted)

Generation total revenues net of purchased power and fuel expense:

	2013			2012			2011		
	RNF from external customers (a)	Intersegment RNF	Total RNF	RNF from external customers (a)	Intersegment RNF	Total RNF	RNF from external customers (a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 3,273	$ (3)	$ 3,270	$ 3,477	$ (44)	$ 3,433	$ 3,350	$ —	$ 3,350
Midwest	2,585	1	2,586	2,974	24	2,998	3,547	—	3,547
New England	217	(32)	185	151	45	196	9	—	9
New York	14	(18)	(4)	101	(25)	76	—	—	—
ERCOT	604	(168)	436	403	2	405	84	—	84
Other Regions (b)	334	(133)	201	53	78	131	(14)	—	(14)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 7,027	$ (353)	$ 6,674	$ 7,159	$ 80	$ 7,239	$ 6,976	$ —	$ 6,976
Other (c)	406	353	759	217	(80)	137	(118)	—	(118)
Total Generation Revenues net of purchased power and fuel expense	$ 7,433	$ —	$ 7,433	$ 7,376	$ —	$ 7,376	$ 6,858	$ —	$ 6,858

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $488 million and $1,098 million, for the years ended December 31, 2013 and 2012, respectively, and the elimination of intersegment revenues.

(Dollars in millions, except per share data unless otherwise noted)

25. Related Party Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon

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

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
PECO [(a)]	$ 10	$ 6	$ 9
CENG [(b)]	56	42	—
BGE	4	—	—
Total operating revenues from affiliates	$ 70	$ 48	$ 9
Purchase power and fuel from affiliates:			
CENG [(c)]	$ 992	$ 793	$ —
Keystone Fuels, LLC	144	119	68
Conemaugh Fuels, LLC	98	101	69
Safe Harbor Water Power Corp	22	23	—
Total purchase power and fuel from affiliates	$1,256	$1,036	$137
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II [(f)]	16	12	—
Total interest expense to affiliates, net	$ 41	$ 37	$ 25
Earnings (losses) in equity method investments:			
CENG [(e)]	$ 9	$ (99)	$ —
Qualifying facilities and domestic power projects	1	8	(1)
Total earnings (losses) in equity method investments	$ 10	$ (91)	$ (1)

(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2013	December 31, 2012
Investments in affiliates:		
ComEd Financing III	$ 6	$ 6
PECO Energy Capital Corporation	4	4
PECO Trust IV	4	4
BGE Capital Trust II	8	8
Total investments in affiliates	$ 22	$ 22
Receivables from affiliates (current):		
CENG (b)	$ 3	$ 16
Payables to affiliates (current):		
CENG (c)	$ 85	$ 83
ComEd Financing III	4	4
PECO Trust III	1	1
BGE Capital Trust II	4	4
Keystone Fuels, LLC	12	11
Conemaugh Fuels, LLC	9	9
Other	1	—
Total payables to affiliates (current)	$ 116	$ 112
Long-term debt due to financing trusts:		
ComEd Financing III	$206	$206
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	258	258
Total long-term debt due to financing trusts	$648	$648

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statement of Operations. See Note 3—Regulatory Matters for additional information.

(b) Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided. In addition to the SSA, Generation has a power services agency agreement (PSAA) with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. At the closing, as described under the Master Agreement, the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(c) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation has a PPA under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon completion of the Put Option Agreement transaction. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(d) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

(Dollars in millions, except per share data unless otherwise noted)

(e) Generation's total gain (loss) in equity method investments includes equity investment income (loss) and amortization of basis difference. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.
(f) The BGE Capital Trust II portion of Exelon's interest expense to affiliates, net, for December 31, 2012 excludes $4 million of expense incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012.

Transactions involving Generation, ComEd, PECO and BGE are further described in the tables below.

Generation

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

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
ComEd [(a)]	$ 506	$ 795	$ 653
PECO [(b)]	405	543	508
BGE [(c)]	455	322	—
CENG [(d)]	56	42	—
BSC	1	—	—
Total operating revenues from affiliates	$1,423	$1,702	$1,161
Purchase power and fuel from affiliates:			
PECO	$ —	$ —	$ 1
ComEd	1	—	—
BGE	13	8	—
CENG [(e)]	992	793	—
Keystone Fuels, LLC	144	119	68
Conemaugh Fuels, LLC	98	101	69
Safe Harbor Water Power Corporation	22	23	—
Total purchase power and fuel from affiliates	$1,270	$1,044	$ 138
Operating and maintenance from affiliates:			
ComEd [(f)]	$ 2	$ 2	$ 2
PECO [(f)]	1	3	5
BSC [(g)]	571	625	314
Total operating and maintenance from affiliates	$ 574	$ 630	$ 321
Interest expense to affiliates, net:			
Exelon Corporate	$ 59	$ 75	$ —
Earnings (losses) in equity method investments			
CENG [(h)]	9	(99)	—
Qualifying facilities and domestic power projects	1	8	(1)
Total earnings (losses) in equity method investments	$ 10	$ (91)	$ (1)
Cash distribution paid to member	$ 625	$1,626	$ 172
Contribution from member	$ 26	$ 48	$ 30

(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2013	December 31, 2012
Mark-to-market derivative assets with affiliates (current):		
ComEd (i)	$ —	$ 226
Receivables from affiliates (current):		
CENG (d)	$ 3	$ —
ComEd (a)(j)	38	54
PECO (b)	38	56
BGE (c)	27	31
Other	2	—
Total receivables from affiliates (current)	$ 108	$ 141
Receivable from affiliate (noncurrent)		
Exelon Corporate	$ —	$ 1
Payables to affiliates (current):		
CENG (e)	$ 85	$ 83
Exelon Corporate (k)	7	33
BSC (g)	66	77
Keystone Fuels, LLC	12	11
Conemaugh Fuels, LLC	9	9
Other	2	—
Total payables to affiliates (current)	$ 181	$ 213
Payables to affiliates (noncurrent):		
ComEd (l)	$2,293	$2,037
PECO (l)	447	360
Total payables to affiliates (noncurrent)	$2,740	$2,397

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3—Regulatory Matters for additional information.

(b) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has five-year and ten-year agreements with PECO to sell non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information.

(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

(d) Exelon has a shared services agreement with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided. In addition to the SSA, Generation has a power services agency agreement with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. At the closing, as described under the Master Agreement, the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(e) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation has a PPA under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG. This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon completion of the Put Option Agreement transaction. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(Dollars in millions, except per share data unless otherwise noted)

(f) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.

(g) Generation receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

(h) Generation's total gain (loss) in equity method investments includes equity income (loss) and amortization of basis difference. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(i) Represents the fair value of Generation's five-year financial swap contract with ComEd, which ended in 2013.

(j) Generation had a $53 million receivable from ComEd at December 31, 2012 associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for additional information.

(k) As of December 31, 2013 and 2012, the balance consists of interest owed to Exelon Corporation related to the senior unsecured notes. In addition, the balance at December 31, 2012, includes expense related to certain invoices Exelon Corporation processed on behalf of Generation.

(l) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 15—Asset Retirement Obligations.

ComEd

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

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates			
Generation	$ 3	$ 2	$ 2
Purchased power from affiliate			
Generation [(a)]	$512	$789	$653
Operating and maintenance from affiliate			
BSC [(b)]	$157	$163	$158
Interest expense to affiliates, net:			
Exelon Corporate	$—	$—	$ 2
ComEd Financing III	13	13	13
Total interest expense to affiliates, net	$ 13	$ 13	$ 15
Capitalized costs			
BSC [(b)]	$ 69	$ 92	$ 85
Cash dividends paid to parent	$220	$ 105	$300
Contribution from parent	$—	$ 11	$ 11

(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2013	December 31, 2012
Prepaid voluntary employee beneficiary association trust (c)	$ 13	$ 10
Investment in affiliate		
ComEd Financing III	$ 6	$ 6
Receivable from affiliates (current):		
Voluntary employee beneficiary association trust	$ 3	$ —
BGE	—	3
Total receivable from affiliates (current)	$ 3	$ 3
Receivable from affiliates (noncurrent):		
Generation (d)	$2,293	$2,037
Exelon Corporate (g)	176	2
Total receivable from affiliates (noncurrent)	$2,469	$2,039
Payables to affiliates (current):		
Generation (a)(e)	$ 38	$ 54
BSC (b)	30	35
ComEd Financing III	4	4
Exelon Corporate	9	2
Other	2	2
Total payables to affiliates (current)	$ 83	$ 97
Mark-to-market derivative liability with affiliate (current)		
Generation (f)	$ —	$ 226
Mark-to-market derivative liability with affiliate (noncurrent)		
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 206	$ 206

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation established as part of the Illinois Settlement Legislation. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for additional information.
(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.
(d) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.
(e) ComEd had a $53 million payable to Generation at December 31, 2012, associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement Legislation. See Note 3—Regulatory Matters and Note 12—Derivative Financial Information for additional information.
(f) To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap with Generation, which ended in 2013.
(g) In 2013, represents indemnification from Exelon Corporate related to the like-kind exchange transaction.

(Dollars in millions, except per share data unless otherwise noted)

PECO

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

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
Generation [(a)]	$ 1	$ 3	$ 5
Purchased power from affiliate			
Generation [(b)]	$392	$533	$495
Operating and maintenance from affiliates:			
BSC [(c)]	$ 98	$ 107	$ 92
Generation	3	4	4
Total operating and maintenance from affiliates	$ 101	$ 111	$ 96
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 12
Capitalized costs			
BSC [(c)]	$ 46	$ 54	$ 60
Cash dividends paid to parent	$332	$343	$348
Contribution from parent	$ 27	$ 9	$ 18

	December 31,	
	2013	2012
Prepaid voluntary employee beneficiary association trust [(d)]	$ 3	$ 2
Investments in affiliates:		
PECO Energy Capital Corporation	$ 4	$ 4
PECO Trust IV	4	4
Total investments in affiliates	$ 8	$ 8
Receivable from affiliate (noncurrent):		
BGE	$ 3	$ 2
Receivable from affiliate (noncurrent):		
Generation [(e)]	$447	$360
Payables to affiliates (current):		
Generation [(b)]	$ 38	$ 56
BSC [(c)]	17	18
Exelon Corporate	2	1
PECO Trust III	1	1
Total payables to affiliates (current)	$ 58	$ 76
Long-term debt to financing trusts:		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.

(Dollars in millions, except per share data unless otherwise noted)

(b) PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

BGE

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

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
Generation [a]	$ 13	$ 10	$ 8
Purchased power from affiliate			
Generation [b]	$452	$396	$348
Operating and maintenance from affiliates:			
BSC [c]	$ 83	$ 106	$ 150
Interest expense to affiliates, net:			
BGE Capital Trust II	$ 16	$ 16	$ 16
Capitalized costs			
BSC [c]	$ 15	$ 21	$ 29
Cash dividends paid to parent	$—	$—	$ (85)
Contribution from parent	$—	$ 66	$—

	December 31,	
	2013	2012
Prepaid voluntary employee beneficiary association trust [d]	$ 1	$—
Investments in affiliates:		
BGE Capital Trust II	$ 8	$ 8
Payables to affiliates (current):		
Generation [b]	$ 27	$ 31
BSC [c]	20	12
Exelon [d]	1	17
ComEd	—	3
PECO	3	2
BGE Capital Trust II	4	4
Total payables to affiliates (current)	$ 55	$ 69
Long-term debt to BGE financing trust		
BGE Capital Trust II	$258	$258

(a) BGE provides energy to Generation for Generation's own use.

(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) BGE receives a variety of corporate support services from Exelon Corporate, including payroll and benefits services.

26. Quarterly Data (Unaudited) (Exelon, Generation, ComEd and PECO)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net (Loss) Income on Common Stock	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 6,082	$ 4,690	$ 508	$ 359	$ (4)	$ 200
June 30	6,141	5,966	1,005	714	490	286
September 30	6,502	6,579	1,254	603	738	296
December 31	6,163	6,254	889	704	495	378

	Average Basic Shares Outstanding (in millions)		Net (Loss) Income per Basic Share	
	2013	2012	2013	2012
Quarter ended:				
March 31	855	705	$ (0.01)	$ 0.28
June 30	856	853	0.57	0.34
September 30	857	854	0.86	0.35
December 31	856	854	0.60	0.44

	Average Diluted Shares Outstanding (in millions)		Net (Loss) Income per Diluted Share	
	2013	2012	2013	2012
Quarter ended:				
March 31	855	707	$ (0.01)	$ 0.28
June 30	860	856	0.57	0.33
September 30	860	857	0.86	0.35
December 31	860	857	0.59	0.44

(Dollars in millions, except per share data unless otherwise noted)

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2013				2012			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 30.59	$ 32.42	$ 37.80	$ 34.56	$ 37.50	$ 39.82	$ 39.37	$ 43.70
Low price	26.64	29.42	29.84	29.10	28.40	34.54	36.27	38.31
Close	27.39	29.64	30.88	34.48	29.74	35.58	37.62	39.21
Dividends	0.310	0.310	0.310	0.525	0.525	0.525	0.525	0.525

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income on Membership Interest	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$3,533	$2,743	$ (64)	$ 272	$ (18)	$ 168
June 30	4,070	3,765	603	384	330	166
September 30	4,255	4,031	721	174	490	91
December 31	3,772	3,898	405	290	269	137

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net (Loss) Income	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 1,160	$ 1,388	$ 209	$ 226	$ (81)	$ 87
June 30	1,080	1,281	232	142	96	42
September 30	1,156	1,484	278	218	126	90
December 31	1,068	1,290	236	300	109	160

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 895	$ 875	$ 203	$ 177	$121	$ 96
June 30	672	715	138	151	72	79
September 30	728	806	155	178	92	122
December 31	805	790	168	117	102	79

(Dollars in millions, except per share data unless otherwise noted)

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income (Loss)		Net Income (Loss) attributable to Common Shareholders	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 880	$ 697	$163	$(11)	$ 77	$ (33)
June 30	653	616	69	52	22	13
September 30	737	720	114	30	50	(4)
December 31	794	703	101	61	47	15

27. Subsequent Events (Exelon and PECO)

On February 5, 2014, a winter storm which brought a mix of snow, ice and freezing rain to the region interrupted electric service delivery to nearly 715,000 customers in PECO's service territory. Restoration efforts are continuing and will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will have a material impact to Exelon's and PECO's results of operations and cash flows for the first quarter of 2014.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Exelon, Generation, ComEd, PECO and BGE—Disclosure Controls and Procedures

During the fourth quarter of 2013, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2013, the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

Exelon, Generation, ComEd, PECO and BGE—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

Exelon, Generation, ComEd, PECO and BGE—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2013. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2013 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

Exelon, Generation and ComEd

Anne R. Pramaggiore, President and Chief Operating Officer of ComEd, Michael J. Pacilio, President, Exelon Nuclear and Chief Nuclear Officer, Generation, and Sunil Garg, President, Exelon Power and Senior Vice President, Generation, each entered into a Change in Control Employment Agreement effective as of February 10, 2011. The terms of these change in control employment agreements are substantially the same as the change in control employment agreements entered into by other senior executives and previously disclosed, except that the agreements with Ms. Pramaggiore and Messrs. Pacilio and Garg do not include excise tax gross-up provisions, consistent with a policy adopted by the compensation committee in April 2009. The form of Change in Control Employment Agreement is attached hereto as Exhibit 10-44.

PECO and BGE

None.

PART III

Exelon Generation Company, LLC, Baltimore Gas and Electric Company, and PECO Energy Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, BGE, and PECO are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 13, 2014.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2014 proxy statement (2014 Exelon Proxy Statement) and the ComEd information statements to be filed with the SEC before April 30, 2014 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com*. The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com*, or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the 2014 Exelon Proxy Statement or the ComEd 2014 information statements and incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the 2014 Exelon Proxy Statement or the ComEd 2014 information statements and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[C] Weighted-average price of outstanding Options, warrants and rights (note 2)	[D] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [B] (Note 3)
Equity compensation plans approved by security holders	29,447,000	$ 37.12	36,556,000

(1) Balance includes stock options, unvested performance shares, and unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation. For performance shares and performance share transition awards granted in 2013, the total includes the maximum number of shares that could be granted, if performance, total shareholder return modifier, and individual performance multipliers were all at maximum, a total of 4,599,000 shares. At target, the number of securities to be issued for such awards is 2,586,000. The deferred stock units granted to directors includes 286,600 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors, and 94,200 shares to be issued upon the conversion of stock units held by members of the Exelon board of directors that were earned under a legacy Constellation Energy Group plan. Conversion of stock units to shares will occur after the director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) Includes outstanding restricted stock units and performance shares that can be exercised for no consideration. Without such instruments, the weighted-average price of outstanding options, warrants and rights shown in column [C] would be $46.07.

(3) Includes 24,441,000 shares available for issuance from the company's employee stock purchase plan.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions* and *Director Independence* in the 2014 Exelon Proxy Statement or the ComEd 2014 information statements and incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2014* in the Proxy Statement and incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2013 and 2012 and for the Years Ended December 31, 2013, 2012 and 2011

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating expenses			
Operating and maintenance	$ 9	$ 201	$ 56
Operating and maintenance from affiliates	34	72	44
Other	12	6	4
Total operating expenses	55	279	104
Operating loss	(55)	(279)	(104)
Other income and (deductions)			
Interest expense, net	(116)	(153)	(75)
Equity in earnings of investments	1,903	1,278	2,662
Interest income from affiliates, net	36	75	1
Other, net	(78)	7	8
Total other income	1,745	1,207	2,596
Income before income taxes	1,690	928	2,492
Income taxes	(29)	(232)	(3)
Net income	$ 1,719	$ 1,160	$ 2,495
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs, net of taxes of $0, $1 and $(4), respectively	—	1	(5)
Actuarial loss reclassified to periodic cost, net of taxes of $133, $110 and $93, respectively	208	168	136
Transition obligation reclassified to periodic cost, net of taxes of $0, $2 and $2, respectively	—	2	4
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $430, $(237) and $(171), respectively	669	(371)	(250)
Unrealized gain (loss) on cash flow hedges, net of taxes of $(166), $(68) and $39, respectively	(248)	(120)	88
Unrealized gain on marketable securities, net of taxes of $0, $(1) and $0, respectively	2	2	—
Unrealized gain (loss) on equity investments, net of taxes of $71, $1 and $0, respectively	106	1	—
Unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	(10)	—	—
Other comprehensive income (loss)	727	(317)	(27)
Comprehensive income	$2,446	$ 843	$2,468

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Net cash flows provided by operating activities	$ 1,053	$ 2,131	$ 766
Cash flows from investing activities			
Changes in Exelon intercompany money pool	(60)	—	—
Note receivable from affiliates	484	—	—
Capital expenditures	—	(30)	(28)
Return on capital from equity method investee	—	—	(1)
Cash and restricted cash acquired from Constellation	—	679	—
Change in restricted cash	38	(38)	—
Investment in affiliates	(38)	(67)	(65)
Other investing activities	15	—	—
Net cash flows provided by (used in) investing activities	439	544	(94)
Cash flows from financing activities			
Cash receipts from intercompany money pool	—	(703)	20
Changes in short-term debt	10	(161)	161
Retirement of long-term debt	(450)	(77)	—
Dividends paid on common stock	(1,249)	(1,716)	(1,393)
Proceeds from employee stock plans	47	73	38
Other financing activities	(6)	30	(1)
Net cash flows used in financing activities	(1,648)	(2,554)	(1,175)
Increase (decrease) in cash and cash equivalents	(156)	121	(503)
Cash and cash equivalents at beginning of period	159	38	541
Cash and cash equivalents at end of period	$ 3	$ 159	$ 38

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 3	$ 159
Restricted cash and investments	—	38
Accounts receivable, net		
Other accounts receivable	72	25
Accounts receivable from affiliates	22	87
Deferred income taxes	27	—
Notes receivable from affiliates	179	119
Regulatory assets	233	381
Other	1	2
Total current assets	537	811
Property, plant and equipment, net	57	59
Deferred debits and other assets		
Regulatory assets	3,005	3,932
Investments in affiliates	26,390	25,576
Deferred income taxes	1,890	2,437
Notes receivable from affiliates	1,522	2,007
Other	17	42
Total deferred debits and other assets	32,824	33,994
Total assets	$33,418	$34,864

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 10	$ —
Accounts payable	43	101
Unamortized energy contract liabilities	12	77
Accrued expenses	106	110
Deferred income taxes	26	55
Regulatory liabilities	2	—
Other	54	60
Total current liabilities	253	403
Long-term debt	3,033	3,576
Long-term debt to affiliate	176	—
Deferred credits and other liabilities		
Regulatory liabilities	43	—
Pension obligations	6,444	8,252
Non-pension postretirement benefit obligations	393	1,071
Unamortized energy contract liabilities	—	12
Deferred income taxes	70	—
Other	271	116
Total deferred credits and other liabilities	7,221	9,451
Total liabilities	10,683	13,430
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 857 and 855 shares outstanding at December 31, 2013 and 2012, respectively)	16,741	16,632
Treasury stock, at cost (35 shares held at December 31, 2013 and 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,358	9,893
Accumulated other comprehensive loss, net	(2,040)	(2,767)
Total shareholders' equity	22,732	21,431
BGE preference stock not subject to mandatory redemption	3	3
Total liabilities and shareholders' equity	$33,418	$34,864

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock. Exelon owned none of PECO's preference securities, which PECO redeemed in 2013.

2. Merger with Constellation

On March 12, 2012, Exelon Corporation completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including the customer supply and generation businesses that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information on the merger with Constellation. Also see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information on BGE's push-down accounting treatment.

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at both December 31, 2013 and December 31, 2012.

Credit Agreements

On August 10, 2013, Exelon Corporate amended and extended its unsecured syndicated revolving credit facility with aggregate bank commitments of $500 million through August 10, 2018. As of December 31, 2013, Exelon Corporate had available capacity under those commitments of $498 million. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporate's credit agreement.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2013 and December 31, 2012:

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
Senior unsecured notes	4.55% – 7.60%	2015-2035	$2,658	$3,108
Unamortized debt discount and premium, net			2	2
Fair value adjustment			383	455
Fair value hedge carrying value adjustment, net			—	11
Long-term debt due within one year			(10)	—
Long-term debt			$3,033	$3,576

Exelon Corporate will not have any long-term debt maturities in 2014. The debt maturities for the periods 2015, 2016, 2017, 2018 and thereafter are as follows:

2015	$ 1,350
2016	—
2017	—
2018	—
Remaining years	1,308
Total long-term debt	$2,658

4. Commitments and Contingencies

See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters and fund transfer restrictions.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

5. Related Party Transactions

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

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating and maintenance from affiliates:			
Business Services Company, LLC (a)	$ 34	$ 72	$ 44
Interest income from affiliates, net	$ 36	$ 75	$ 1
Equity in earnings of investments:			
Exelon Energy Delivery Company, LLC (b)	$ 834	$ 713	$ 801
Exelon Ventures Company, LLC (c)	1,076	564	1,769
UII, LLC	(2)	25	18
Exelon Transmission Company, LLC	(5)	(3)	(3)
Exelon Consolidations (d)	—	(21)	77
Total equity in earnings of investments	$1,903	$1,278	$2,662
Cash contributions received from affiliates	$1,175	$2,074	$ 820

(in millions)	December 31, 2013	2012
Accounts receivable from affiliates (current):		
Business Services Company, LLC (a)	$ 3	$ 33
Generation	7	33
ComEd	9	2
PECO	2	2
BGE	1	17
Total accounts receivable from affiliates (current)	$ 22	$ 87
Notes receivable from affiliates (current):		
Business Services Company, LLC (a)	$ 179	$ 119
Investments in affiliates:		
Business Services Company, LLC (a)	$ 201	$ 181
Exelon Energy Delivery Company, LLC (b)	12,956	12,466
Exelon Ventures Company, LLC (c)	12,750	12,444
UII, LLC	470	472
Exelon Transmission Company, LLC	3	4
VEBA	10	9
Total investments in affiliates	$26,390	$25,576
Notes receivable from affiliates (non-current):		
Generation	$ 1,522	$ 2,007
Long-term debt to affiliates (non-current):		
ComEd	$ 176	$ —

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO and BGE.
(c) Exelon Ventures Company, LLC primarily consists of Generation.
(d) Equity in earnings of investments for Exelon Consolidations represents the intercompany income component that offsets the corresponding intercompany expense at Generation for upgrades in transmission assets owned by ComEd, which are reflected as assets at Exelon Corporate.

Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts [(a)]	$ 293	$ 121	$ 37[(c)]	$ 179[(d)]	$ 272
Deferred tax valuation allowance	36	1		24	13
Reserve for obsolete materials	53	17	—	12	58
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts [(a)]	$ 199	$ 144	$ 136[(b)(c)]	$ 186[(d)]	$ 293
Deferred tax valuation allowance	10	18	18[(b)]	10	36
Reserve for obsolete materials	60	2	2[(b)]	11	53
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts [(a)]	$ 211	$ 121	$ 32[(c)]	$ 165[(d)]	$ 199
Deferred tax valuation allowance	9	1	—	—	10
Reserve for obsolete materials	56	6	—	2	60

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $9 million, $8 million, and $9 million for the years ended December 31, 2013, 2012, and 2011, respectively.
(b) Primarily represents the addition of Constellation's and BGE's results as of March 12, 2012, the date of the merger.
(c) Includes charges for late payments and non-service receivables.
(d) Write-off of individual accounts receivable.

Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in millions)			
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 84	$ (16)	$ —	$ 11	$ 57
Deferred tax valuation allowance	35	1	—	25	11
Reserve for obsolete materials	50	16	—	11	55
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 29	$ —	$ 66[(a)]	$ 11	$ 84
Deferred tax valuation allowance	—	17	18[(a)]	—	35
Reserve for obsolete materials	59	—	2[(a)]	11	50
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 32	$ —	$ —	$ 3	$ 29
Reserve for obsolete materials	55	4	—	—	59

(a) Represents the addition of Constellation's results as of March 12, 2012, the date of the merger.

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 70	$ 33	$ 29(a)	$ 70(b)	$ 62
Reserve for obsolete materials	2	1	—	1	2
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 78	$ 42	$ 26(a)	$ 76(b)	$ 70
Reserve for obsolete materials	1	1	—	—	2
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 80	$ 57	$ 15(a)	$ 74(b)	$ 78
Reserve for obsolete materials	1	2	—	2	1

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in millions)			
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts [(a)]	$ 99	$ 61	$ 7[(b)]	$ 60[(c)]	$ 107
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts [(a)]	$ 92	$ 60	$ 8[(b)]	$ 61[(c)]	$ 99
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts [(a)]	$ 99	$ 64	$ 17[(b)]	$ 88[(c)]	$ 92
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $9 million, $8 million, and $9 million for the years ended December 31, 2013, 2012, and 2011, respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

Baltimore Gas and Electric Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 40	$ 43	$ 1[b]	$ 38[a]	$ 46
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 38	$ 45	$ —	$ 43[a]	$ 40
Deferred tax valuation allowance	—	1	—	—	1
Reserve for obsolete materials	—	1	—	—	1
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 36	$ 39	$ —	$ 37[a]	$ 38

(a) Write-off of individual accounts receivable.
(b) Primarily charges for late payments.

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1)
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit 2-1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
2-9	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, effective as of March 12, 2012 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 3-1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).

Exhibit No.	Description
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock” (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-1839, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
3-11	Bylaws of Baltimore Gas and Electric Company, as amended and restated as of May 10, 2012.
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File Nos. 1-12869 and 1-1910.)
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).
4-1-1	Supplemental Indentures to PECO Energy Company’s First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2-2881	B-1(c)
March 1, 1937	2-2881	B-1(g)
December 1, 1941	2-4863	B-1(h)
November 1, 1944	2-5472	B-1(i)
December 1, 1946	2-6821	7-1(j)
September 1, 1957	2-13562	2(b)-17
May 1, 1958	2-14020	2(b)-18
March 1, 1968	2-34051	2(b)-24
March 1, 1981	2-72802	4-46
March 1, 1981	2-72802	4-47

Dated as of	File Reference	Exhibit No.
December 1, 1984	1-01401, 1984 Form 10-K	4-2(b)
March 1, 1993	1-01401, 1992 Form 10-K	4(e)-86
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-88
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-89
April 15, 2004	0-6844, September 30, 2004 Form 10-Q	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1

4-2 Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-183751, Form S-3, Prospectus).

4-3 Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).

4-3-1 Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7	2-1
April 1, 1953	2-60201, Form S-7	2-1
March 31, 1967	2-60201, Form S-7	2-1
April 1,1967	2-60201, Form S-7	2-1
February 28, 1969	2-60201, Form S-7	2-1
May 29, 1970	2-60201, Form S-7	2-1
June 1, 1971	2-60201, Form S-7	2-1
April 1, 1972	2-60201, Form S-7	2-1
May 31, 1972	2-60201, Form S-7	2-1
June 15, 1973	2-60201, Form S-7	2-1
May 31, 1974	2-60201, Form S-7	2-1
June 13, 1975	2-60201, Form S-7	2-1

Dated as of	File Reference	Exhibit No.
May 28, 1976	2-60201, Form S-7	2-1
June 3, 1977	2-60201, Form S-7	2-1
May 17, 1978	2-99665, Form S-3	4-3
August 31, 1978	2-99665, Form S-3	4-3
June 18, 1979	2-99665, Form S-3	4-3
June 20, 1980	2-99665, Form S-3	4-3
April 16, 1981	2-99665, Form S-3	4-3
April 30, 1982	2-99665, Form S-3	4-3
April 15, 1983	2-99665, Form S-3	4-3
April 13, 1984	2-99665, Form S-3	4-3
April 15, 1985	2-99665, Form S-3	4-3
April 15, 1986	33-6879, Form S-3	4-9
January 15, 1994	1-1839, 1993 Form 10-K	4-15
January 13, 2003	1-1839, Form 8-K dated January 22, 2003	4-4
March 14, 2003	1-1839, Form 8-K dated April 7, 2003	4-4
February 22, 2006	1-1839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	1-1839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	1-1839, Form 8-K dated October 2, 2006	4.1
March 1, 2007	1-1839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	1-1839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	1-1839, Form 8-K dated January 16, 2008	4.1
March 10, 2008	1-1839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
January 4, 2011	001-01839, Form 8-K dated January 18, 2011	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1

Exhibit No.	Description
4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13).
4-5	Indenture dated December 19, 2003 between Exelon Generation Company, LLC and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1)
4-11	Form of 6.000% Senior Secured Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.2)
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-15	Form of $800,000,000 4.90% senior notes due 2015 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.2).
4-16	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-17	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-18	Form of 5.20% Exelon Generation Company, LLC Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).

Exhibit No.	Description
4-19	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-20	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-21	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-22	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation Energy Group, Inc., File No. 333-75217.)
4-23	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation Energy Group, Inc., File No. 333-102723.)
4-24	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991.)
4-25	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869.)
4-26	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
4-27	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1)
4-28	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
4-29	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01.)
4-30	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991.)

Exhibit No.	Description
4-31	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
4-32	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01.)
4-33	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
4-34	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Baltimore Gas and Electric Company, File No. 1 1910.)
4-35	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869.)
4-36	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4)
4-37	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
4-38	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
10-1	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.1)
10-2	Exelon Corporation Retirement Program (As Amended and Restated Effective January 1, 2013).
10-3	Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.3)
10-4	Exelon Corporation Long-Term Incentive Plan As Amended and Restated Effective January 28, 2002* (File No. 1-16169, Exelon Proxy Statement dated March 13, 2002, Appendix B).
10-5-1	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).

Exhibit No.	Description
10-5-2	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-5-3	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-6	Exelon Corporation Employee Savings Plan (As Amended and Restated Effective January 1, 2013).
10-7	Exelon Corporation Cash Balance Pension Plan (As Amended and Restated Effective January 1, 2013).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives Effective January 1, 2004 (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2009 Form 10-K, Exhibit 10.21).
10-15	Form of change in control employment agreement for senior executives effective January 1, 2009 * (File No. 001-16169. 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective July 1, 2013. (File No. 1-16169, Schedule 14A dated March 14, 2013 Appendix A).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective April 1, 2013).*
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No, 001-16169, 2008 Form 10-K, Exhibit 10.30).
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Exelon Generation Company, LLC and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).

Exhibit No.	Description
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Reserved.
10-34	Exelon Corporation 2011 Long-Term Incentive Plan (File No. 1-16169, Schedule 14A dated March 18, 2010, Appendix A).
10-35	Form of Change in Control Employment Agreement Effective February 10, 2011. * (File 1-16169, 2011 Form 10-K, Exhibit 10-44).
10-36	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 10-2).
10-37	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 10-3).
10-38	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 10-4).
10-39	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-40	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1)
10-41	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2).

Exhibit No.	Description
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (Designated as Exhibit No. 10(e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. * (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)

Exhibit No.	Description
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-55	Form of Grant Agreement for Stock Units with Sales Restriction. * (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910.)
10-64	Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*

Exhibit No.	Description
10-65	First Amendment to the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*
10-66	Second Amendment to the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*
10-67	Third Amendment to the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*
10-68	Constellation Energy Group, Inc. Employee Savings Plan (Amended and Restated Effective January 31, 2012)*
10-69	First Amendment to the Constellation Energy Group, Inc. Employee Savings Plan (Amended and Restated Effective January 31, 2012)*
10-70	Second Amendment to the Constellation Energy Group, Inc. Employee Savings Plan (Amended and Restated Effective January 31, 2012)*
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	John A. Canning, Jr.
24-4	Christopher M. Crane
24-5	Yves C. de Balmann
24-6	Nicholas DeBenedictis
24-7	Nelson A. Diaz

Exhibit No.	Description
24-8	Sue L. Gin
24-9	Paul L. Joskow
24-10	Robert J. Lawless
24-11	Richard W. Mies
24-12	William C. Richardson
24-13	John W. Rogers, Jr.
24-14	Mayo A. Shattuck III
24-15	Stephen D. Steinour
	Power of Attorney (Commonwealth Edison Company)
24-16	James W. Compton
24-17	Christopher M. Crane
24-18	A. Steven Crown
24-19	Nicholas DeBenedictis
24-20	Peter V. Fazio, Jr.
24-21	Sue L. Gin
24-22	Michael Moskow
24-23	Denis O’Brien
24-24	Anne R. Pramaggiore
24-25	Jesse H. Ruiz
	Power of Attorney (PECO Energy Company)
24-26	Craig L. Adams
24-27	Christopher M. Crane
24-28	M. Walter D’Alessio
24-29	Nicholas DeBenedictis
24-30	Nelson A. Diaz
24-31	Rosemarie B. Greco
24-32	Charisse R. Lillie
24-33	Denis O’Brien
24-34	Ronald Rubin
	Power of Attorney (Baltimore Gas and Electric Company)
24-35	Ann C. Berzin
24-36	Christopher M. Crane
24-37	Michael E. Cryor
24-38	James R. Curtiss
24-39	Kenneth W. DeFontes, Jr.
24-40	Joseph Haskins, Jr.
24-41	Carla D. Hayden
24-42	Denis O’Brien

Exhibit No.	Description
	Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Kenneth W. DeFontes Jr. for Baltimore Gas and Electric Company
31-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Kenneth W. DeFontes Jr. for Baltimore Gas and Electric Company
32-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

EXELON CORPORATION

By: /S/ CHRISTOPHER M. CRANE
Name: **Christopher M. Crane**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	Title
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/S/ JONATHAN W. THAYER **Jonathan W. Thayer**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ DUANE M. DESPARTE **Duane M. DesParte**	Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Darryl M. Bradford, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
John A. Canning, Jr.
Yves C. de Balmann
Nicholas DeBenedictis
Nelson A. Diaz
Sue L. Gin
Paul L. Joskow
Robert J. Lawless
Richard W. Mies
William C. Richardson
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour

By: /S/ DARRYL M. BRADFORD February 13, 2014
Name: **Darryl M. Bradford**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

EXELON GENERATION COMPANY, LLC

By: /S/ KENNETH W. CORNEW
Name: **Kenneth W. Cornew**
Title: **President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	Title
/S/ KENNETH W. CORNEW **Kenneth W. Cornew**	President (Principal Executive Officer)
/S/ BRYAN P. WRIGHT **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

COMMONWEALTH EDISON COMPANY

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	Title
/s/ ANNE R. PRAMAGGIORE **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ JOSEPH R. TRPIK, JR. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ GERALD KOZEL **Gerald J. Kozel**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director
/s/ DENIS P. O'BRIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
A. Steven Crown
Nicholas DeBenedictis
Peter V. Fazio, Jr.
Sue L. Gin
Michael Moskow
Jesse H. Ruiz

By: /s/ ANNE R. PRAMAGGIORE — February 13, 2014
Name: **Anne R. Pramaggiore**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

PECO ENERGY COMPANY

By: /s/ CRAIG L. ADAMS

Name: **Craig L. Adams**

Title: **Chief Executive Officer and President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	Title
/s/ CRAIG L. ADAMS **Craig L. Adams**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ PHILLIP S. BARNETT **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ SCOTT A. BAILEY **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director
/s/ DENIS P. O'BRIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

M. Walter D'Alessio	**Rosemarie B. Greco**
Nelson A. Diaz	**Charisse R. Lillie**
Nicholas DeBenedictis	**Ronald Rubin**

By: /s/ CRAIG L. ADAMS February 13, 2014

Name: **Craig L. Adams**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

BALTIMORE GAS AND ELECTRIC COMPANY

By: /s/ KENNETH W. DEFONTES, JR.
Name: **Kenneth W. DeFontes Jr.**
Title: **Chief Executive Officer and President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	Title
/s/ KENNETH W. DEFONTES, JR. **Kenneth W. DeFontes Jr.**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ CARIM V. KHOUZAMI **Carim V. Khouzami**	Senior Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)
/s/ DAVID M. VAHOS **David M. Vahos**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director
/s/ DENIS P. O'BRIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Kenneth W. DeFontes, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Carla D. Hayden

By: /s/ KENNETH W. DEFONTES, JR. February 13, 2014
Name: **Kenneth W. DeFontes, Jr.**

Exhibit 3.11

BYLAWS

OF

Baltimore Gas and Electric Company

Amended and Restated as of May 10, 2012

Bylaws of
Baltimore Gas and Electric Company

ARTICLE I

MEETINGS OF STOCKHOLDERS

Section 1.—*Annual Meeting.*

The annual meeting of the stockholders for the election of Directors and for the transaction of general business shall be held on any date as determined year to year by the Board of Directors. The time and location of the meeting shall be determined by the Board of Directors.

The Chief Executive Officer of the Company shall prepare, or cause to be prepared, an annual report containing a full and correct statement of the affairs of the Company, including a balance sheet and a financial statement of operations for the preceding fiscal year, which shall be submitted to the stockholders at the annual meeting.

Section 2.—*Special Meeting.*

Special meetings of the stockholders may be held in the City of Baltimore or in any county in which the Company provides service or owns property upon call by the Chairman of the Board, if one is elected, the President, or a majority of the Board of Directors whenever they deem expedient, or upon the written request of the holders of shares entitled to not less than twenty-five percent of all the votes entitled to be cast at such a meeting. Such request of the stockholders shall state the purpose or purposes of the meeting and the matters proposed to be acted on thereat and shall be delivered to the Secretary, who shall inform such stockholders of the reasonably estimated cost of preparing and mailing such notice of the meeting, and upon payment to the Company of such costs the Secretary shall give notice stating the purpose or purposes of the meeting to all stockholders entitled to vote at such meeting. No special meeting need be called upon the request of the holders of the shares entitled to cast less than a majority of all votes entitled to be cast to such meeting, to consider any matter which is substantially the same as a matter voted upon at any special meeting of the stockholders held during the preceding twelve months. The business at all special meetings shall be confined to that specifically named in the notice thereof.

Section 3.—*Notice of Meetings.*

Written or printed notice of every meeting of the stockholders, whether annual or special, stating the place, day, and hour of such meeting and (in the case of special meetings) the business proposed to be transacted shall be given by the Secretary to each stockholder entitled to vote at such meeting not less than ten days but no more than ninety days before the date fixed for such meeting, by electronic mail at his or her e-mail address as it appears on the records of the Company or by depositing such notice in the United States mail addressed to him or her at his or her post office address as it appears on the records of the Company, with postage thereon prepaid.

Section 4.—*Organization of Meeting.*

All meetings of the stockholders shall be called to order by the Chairman of the Board, or if one is not elected or is absent, by the President, or in his or her absence by a Vice President, or in the case of the absence of such officers, then by any stockholder, whereupon the meeting shall organize by electing a chairman. The Secretary of the Company, if present, shall act as secretary of the meeting, unless some other person shall be elected by the meeting to so act. An accurate record of the meeting shall be kept by the secretary thereof, and placed in the record books of the Company.

Section 5.—*Quorum.*

At any meeting of the stockholders, the presence in person or by proxy of stockholders entitled to cast a majority of the votes thereat shall constitute a quorum for the transaction of business. If a quorum be not present at any meeting, holders of a majority of the shares of stock so present or represented may adjourn the meeting either *sine die* or to a date certain.

Section 6.—*Voting.*

At all meetings of the stockholders, each stockholder shall be entitled to one vote for each share of common stock standing in his or her name and, when the preferred or preference stock is entitled to vote, such number of votes as shall be provided in the charter of the Company for each share of preferred and preference stock standing in his or her name, and the votes shall be cast by stockholders in person or by lawful proxy.

Section 7.—*Judge of Election and Tellers.*

The Directors, at a regular or special meeting of stockholders, may (but shall not be required to) appoint a Judge of Election and two Tellers to serve at each meeting of stockholders. If the Directors fail to make such appointments, or if the Judge of Election and/or Tellers, or any of them, fail to appear at the meeting, the chairman of the meeting shall appoint a Judge of Election and/or a Teller or Tellers to serve at that meeting. It shall be the duty of the Tellers to receive the ballots of all the holders of stock entitled to vote and present at a meeting either in person or by proxy, and to count and tally said ballots by the official record of stockholders of the Company, or by a summary prepared therefrom and certified by the Stock Transfer Agent or the Secretary of the Company showing the number of shares of common and, if entitled to vote, preferred and preference stock owned of record by each stockholder, who may be designated therein by name, code number, or otherwise, and certify them to the Judge of Election, and the said Judge shall communicate in writing the result of the balloting so certified by the Tellers to the chairman who shall at once announce the same to the meeting. This certificate, signed by the Tellers and countersigned by the Judge, shall be duly recorded as part of the minutes of the meeting and filed among the records of the Company.

Section 8.—*Record Date for Stockholders and Closing of Transfer Books.*

The Board of Directors may fix, in advance, a date as the record for the determination of the stockholders entitled to notice of, or to vote at, any meeting of stockholders, or entitled to receive payment of any dividend, or entitled to the allotment of any rights, or for any other proper purpose. Such date in any case shall not be more than ninety days (and in the case of a meeting of stockholders not less than ten days) prior to the date on which the particular action requiring such determination of stockholders is to be taken. Only stockholders of record on such date shall be entitled to notice of or to vote at such meeting or to receive such dividends or rights, as the case may be. In lieu of fixing a record date, the Board of Directors may close the stock transfer books of the Company for a period not exceeding twenty days or less than ten days preceding the date of any meeting of stockholders or not exceeding twenty days preceding any other of the above mentioned events.

ARTICLE II

BOARD OF DIRECTORS AND COMMITTEES

Section 1.—*Powers of Directors.*

The business and affairs of the Company shall be managed by a Board of Directors which shall have and may exercise all the powers of the Company, except such as are expressly conferred upon or reserved to the stockholders by law, by the charter, or by these bylaws. Except as otherwise provided herein, the Board of Directors shall appoint the officers for the conduct of the business of the Company, determine their duties and responsibilities and fix their compensation. The Board of Directors may remove any officer.

Section 2.—*Number and Election of Directors.*

The number of Directors (including each Independent Director) shall be set at eight; *provided, however*, that the number of Directors may be increased or decreased by the Board of Directors without an amendment to these bylaws but in no event will there be less than three Directors or more than fifteen Directors. The Directors (including each Independent Director) shall be elected at each Annual Meeting of the Stockholders except as otherwise provided in these bylaws. They shall hold their offices for one year and until their successors are elected and qualified.

Section 3.—*Director Independence and Residency.*

(a) At all times subsequent to the first meeting of the Board of Directors after March 12, 2012, in accordance with the provisions of these bylaws, at least one-third of the Directors in office, and no less than two Directors, shall meet the standards for independence set forth in the New York Stock Exchange Listing Standards, and shall be neither employees nor directors of Exelon Corporation (“Exelon”) or any Exelon affiliate (each such Director, an “Independent Director”). No resignation or removal of an Independent Director at any time when such resignation or removal would result in less than one-third of the Directors in office, or less than two Directors, being Independent Directors shall be effective until as many successor Independent Directors as needed to have at least one-third, and no less than two, of the Directors be Independent Directors shall have accepted their appointments as Independent Directors. In the event that less than one-third of the Directors in office, or less than two Directors, meeting the qualifications therefor are then holding the position of Independent Director, the Board of Directors shall, as soon as practicable, appoint as many successor Independent Directors as needed to have at least one-third, and no less than two, of the Directors be Independent Directors, and until each such vacancy is filled, the Board of Directors shall be prohibited from voting on any action specified in Section 6(b) of this Article II or the proviso to Article VIII. No Independent Director shall at any time serve as trustee in bankruptcy for any affiliate of the Company.

(b) At all times on and after the date hereof, a majority of the Directors in office shall have primary residence or principal place of business or employment in the Company's service territory.

Section 4.—*Removals and Vacancies.*

The stockholders, at any meeting duly called and at which a quorum is present, may remove any Director or Directors from office by the affirmative vote of the holders of a majority of the outstanding shares entitled to the vote thereon, and may elect a successor or successors to fill any resulting vacancies for the unexpired terms of the removed Directors.

Any vacancy occurring in the Board of Directors from any cause other than by reason of removal by the stockholders or an increase in the number of Directors may be filled by a majority of the remaining Directors although such majority is less than a quorum. Any vacancy occurring by reason of an increase in the number of Directors may be filled by action of a majority of Directors. A Director elected to fill a vacancy shall hold office until the next annual meeting of stockholders or until his successor is elected and qualified.

Section 5.—*Meetings of the Board of Directors.*

A regular meeting of the Board of Directors shall be held immediately after the annual meeting of stockholders or any special meeting of the stockholders at which the Board of Directors is elected, and thereafter regular meetings of the Board of Directors shall be held on such dates during the year as may be designated from time to time by the Board of Directors. All meetings of the Board of Directors shall be held at the general offices of the Company in the City of Baltimore or elsewhere, as ordered by the Board of Directors. Of all such meetings (except: the regular meeting held immediately after the election of Directors) the Secretary shall give notice to each Director personally or by electronic mail, by telephone, by telegram directed to, or by written notice deposited in the United States mail addressed to, his residence or business address on record with the Company at least 48 hours before such meeting. Special meetings may be held at any time or place upon the call of the Chairman of the Board or the Chief Executive Officer.

The Chairman of the Board shall preside at all meetings of the Board of Directors, or, if one is not elected or is absent, the President, or one of the Vice Presidents (if a member of the Board of Directors) shall preside. If at any meeting none of the foregoing persons is present, the Directors present shall designate one of their number to preside at such meeting.

Section 6.—*Quorum and Voting.*

(a) A majority of the Directors in office shall constitute a quorum of the Board of Directors for the transaction of business, with the exception of any meeting at which any action described in Section 6(b) of this Article II is considered, at which meeting a quorum shall consist of all Directors. All actions of the Board of Directors (other than those described in Section 6(b) of this Article II) shall require the affirmative vote of a majority of the Directors in attendance at a meeting at which a quorum is present. If a quorum be not present at any meeting, a majority of the Directors present may adjourn to any time and place they may see fit.

(b) Notwithstanding any other provision of these bylaws and any provision of law that otherwise so empowers the Company, the stockholders, the Board of Directors, any Director, any officer or any other person, neither the stockholders nor the Board of Directors nor any Director nor any officer nor any other person shall be authorized or empowered, nor shall they permit the Company, without the unanimous prior approval of the Board of Directors, including the Independent Directors, to (A) commence any case, proceeding or other action on behalf of the Company under any existing or future law of any jurisdiction relating to bankruptcy, insolvency, reorganization, or relief for debtors; (B) institute proceedings to have the Company adjudicated as bankrupt or insolvent; (C) consent to or acquiesce in the institution of bankruptcy or insolvency proceedings against the Company; (D) file a petition or consent to a petition seeking reorganization, arrangement, adjustment, winding up, dissolution, composition, liquidation, or other relief on behalf of the Company of its debts under any federal or state law relating to bankruptcy; (E) apply for, or consent to, or acquiesce in the appointment of, a receiver, liquidator, sequestrator, trustee or other officer with similar powers of such person with respect to the Company; (F) make any assignment for the benefit of the Company's creditors; (G) admit in writing the Company's inability to pay its debts generally as they become due; or (H) remove the unanimous consent requirement set forth above in this Section 6(b) of Article II.

Section 7.—*Committees.*

The Board of Directors is authorized to appoint from among its members such committees as it may, from time to time, deem advisable and to delegate to such committee or committees any of the powers of the Board of Directors which it may lawfully delegate. Each such committee shall consist of at least one Director.

Section 8.—*Fees and Expenses.*

Each member of the Board of Directors, other than salaried officers and employees, shall be paid an annual retainer fee, payable in such amount as shall be specified from time to time by the Board of Directors.

Each member of the Board of Directors, other than salaried officers and employees, shall be paid such fee as shall be specified from time to time by the Board of Directors for attending each regular or special meeting of the Board of Directors and for attending, as a committee member, each meeting of any committee appointed by the Board of Directors. Each Director shall be paid reasonable traveling expenses incident to attendance at meetings of the Board of Directors.

ARTICLE III

OFFICERS

Section 1.—*Officers.*

The Company may have a Chairman of the Board and a Vice Chairman and shall have a President, one or more Vice Presidents, a Treasurer, and a Secretary, who shall be elected by, and hold office at the will of, the Board of Directors. The Chairman of the Board and the Vice Chairman, if one is elected, shall be chosen from among the Directors, and the Board of Directors shall designate either the Chairman of the Board, the Vice Chairman or the President to be the Chief Executive Officer of the Company; provided that the Chief Executive Officer shall reside within the Company's service territory. The Board of Directors shall also elect such other officers as they may deem necessary for the conduct of the business and affairs of the Company. Any two offices, except those of President and Vice President, may be held by the same person, but no person shall sign checks, drafts and promissory notes, or execute, acknowledge or verify any other instrument in more than one capacity, if such instrument is required by law, the charter, these bylaws, a resolution of the Board of Directors or order of the Chief Executive Officer to be signed, executed, acknowledged or verified by two or more officers.

Section 2.—*Duties of the Officers.*

(a) *Chairman of the Board of Directors; Vice Chairman.*

The Chairman of the Board of Directors, if one is elected, shall preside at all meetings of the Board of Directors and of the stockholders, and shall also have such other powers and duties as from time to time may be assigned to him or her by the Board of Directors. The Vice Chairman, if one is elected, shall, in the absence of the Chairman of the Board, or if one is not elected, perform the duties of the Chairman of the Board, and shall also have such other powers and duties as from time to time may be assigned to him or her by the Board of Directors.

(b) *President.*

The President shall have general executive powers, as well as specific powers conferred by these bylaws. The President, any Vice President, or such other persons as may be designated by the Board of Directors, shall sign all special contracts of the Company, countersign checks, drafts and promissory notes, and such other papers as may be directed by the Board of Directors. The President, or any Vice President, together with the Treasurer or an Assistant Treasurer, shall have authority to sell, assign or transfer and deliver any bonds, stocks or other securities owned by the Company. The President shall also have such other powers and duties as from time to time may be assigned to him or her by the Board of Directors. In the absence of the Chairman of the Board and the Vice Chairman, or if one (or both) is (or are) not elected, the President shall perform all the duties of the Chairman of the Board.

(c) *Vice Presidents.*

Each Vice President shall have such powers and duties as may be assigned to him or her by the Board of Directors, or the Chief Executive Officer, as well as the specific powers assigned by these bylaws. A Vice President may be designated by the Board of Directors or the Chief Executive Officer to perform, in the absence of the President, all the duties of the President.

(d) *Treasurer.*

The Treasurer shall have the care and the custody of the funds and valuable papers of the Company, and shall receive and disburse all moneys in such a manner as may be prescribed by the Board of Directors or the Chief Executive Officer. The Treasurer shall have such other powers and duties as may be assigned to him or her by the Board of Directors, or the Chief Executive Officer, as well as specific powers assigned by these bylaws.

(e) *Secretary.*

The Secretary shall attend all meetings of the stockholders and the Board of Directors and shall notify the stockholders and Directors of such meetings in the manner provided in these bylaws. The Secretary shall record the proceedings of all such meetings in books kept for that purpose. The Secretary shall have such other powers and duties as may be assigned to him or her by the Board of Directors or the Chief Executive Officer, as well as the specific powers assigned by these bylaws.

Section 3.—*Removals and Vacancies.*

Any officer may be removed by the Board of Directors whenever, in its judgment, the best interest of the Company will be served thereby. In case of removal, the salary of such officer shall cease. Removal shall be without prejudice to the contractual rights, if any, of the person so removed, but election of an officer shall not of itself create contractual rights.

Any vacancy occurring in any office of the Company shall be filled by the Board of Directors and the officer so elected shall hold office for the unexpired term in respect of which the vacancy occurred or until his or her successor shall be duly elected and qualified.

In any event of absence or temporary disability of any officer of the Company, the Board of Directors may authorize some other person to perform the duties of that office.

ARTICLE IV

LIMITATIONS ON ACTIVITIES

The Company shall:

(a) not participate in the cash pool operated by Exelon or any other Exelon affiliate (other than a subsidiary of the Company) and shall not commingle funds with Exelon or any other Exelon affiliate (other than a subsidiary of the Company);

(b) hold itself out as a separate entity from Exelon, Exelon Energy Delivery Company LLC ("EEDC") and RF HoldCo LLC ("HoldCo"), conduct business in its own name and not assume liability for future debts of Exelon, EEDC or HoldCo;

(c) maintain a separate name from and not use the trademarks, service marks or other intellectual property of Exelon, EEDC or HoldCo;

(d) maintain separate books, accounts and financial statements reflecting its separate assets and liabilities;

(e) maintain arms-length relationships with Exelon, EEDC and HoldCo; and

(f) not (i) guarantee the debt or credit instruments of Exelon or any other Exelon affiliate (other than a subsidiary of the Company); (ii) grant a mortgage or other lien on any property used and useful in providing retail or wholesale utility service to, or otherwise pledge such assets as security for repayment of the principal or interest of any loan or credit instrument of, Exelon or any other Exelon affiliate (other than a subsidiary of the Company); (iii) include in any of the Company's debt or credit agreements cross-default provisions between the Company's securities and the securities of Exelon or any other Exelon affiliate (other than a subsidiary of the Company); or (iv) include in its debt or credit agreements any financial covenants or rating-agency triggers related to Exelon or any other Exelon affiliate (other than a subsidiary of the Company).

ARTICLE V

INDEMNIFICATION

Section 1.—*Procedure.*

The Company shall indemnify any present or former Director or officer of the Company and each Director or elected officer of any direct or indirect wholly-owned subsidiary of the Company who is made, or threatened to be made, a party to a proceeding by reason of his or her service in that capacity or by reason of service, while a Director or officer of the Company and at the request of the Company, as a director or officer of another company, corporation, limited liability company, partnership, trust, employee benefit plan or other enterprise, and the Company shall pay or reimburse reasonable expenses incurred in advance of final disposition of the proceeding, in each case to the fullest extent permitted by the laws of the State of Maryland. The Company may indemnify, and advance reasonable expenses to, other employees and agents of the Company and employees and agents of any subsidiary of the Company to the extent authorized by the Board of Directors. The Company shall follow the procedures required by applicable law in determining persons eligible for indemnification and in making indemnification payments and advances.

Section 2.—*Exclusivity, etc.*

The indemnification and advancement of expenses provided by these bylaws (a) shall not be deemed exclusive of any other rights to which a person seeking indemnification or advance of expenses may be entitled under any law (common or statutory), or any agreement, vote of stockholders or disinterested Directors or other provision that is consistent with law, both as to action in his or her official capacity and as to action in another capacity while holding office or while employed or acting as agent for the Company, (b) shall continue in respect of all events occurring while a person was a Director or officer after such person has ceased to be a Director or officer, and (c) shall inure to the benefit of the estate, heirs, executors and administrators of such person. All rights to indemnification and advance of expenses hereunder shall be deemed to be a contract between the Company and each Director or officer of the Company who serves or served in such capacity at any time while this Article V is in effect. Nothing herein shall prevent the amendment of this Article V, *provided* that no such amendment shall diminish the rights of any person hereunder with respect to events occurring or claims made before its adoption or as to claims made after its adoption in respect of events occurring before its adoption. Any repeal or modification of this Article V shall not in any way diminish any rights to indemnification or advancement of expenses of a Director or officer or the obligations of the Company arising hereunder with respect to events occurring, or claims made, while this Article V or any provision hereof is in effect.

Section 3.—*Severability.*

The invalidity or unenforceability of any provision of this Article V shall not affect the validity or enforceability of any other provision hereof.

ARTICLE VI

CAPITAL STOCK

Section 1.—*Evidence of Stock Ownership.*

Evidence of ownership of stock in the Company shall be pursuant to certificate(s), each of which shall represent the number of shares of stock owned by a stockholder of the Company. Stockholders may request that their stock ownership be represented by certificate(s). Each certificate shall be signed on behalf of the Company by the President or a Vice President and countersigned by the Secretary or the Treasurer, and shall be sealed with the corporate seal. The signatures may be either manual or facsimile. In case any officer who signed any certificate, in facsimile or otherwise, ceases to be such officer of the Company before the certificate is issued, the certificate may nevertheless be issued by the Company with the same effect as if the officer had not ceased to be such officer as of the date of its issue.

Section 2.—*Transfer of Shares.*

Stock shall be transferable only on the books of the Company by assignment in writing by the registered holder thereof, his or her legally constituted attorney, or his or her legal representative, either upon surrender and cancellation of the certificate(s) therefor, if such stock is represented by a certificate, or upon receipt of such other documentation for stock not represented by a certificate as the Board of Directors and the law of the State of Maryland may, from time to time, require.

Section 3.—*Lost, Stolen or Destroyed Certificates.*

No certificate for shares of stock of the Company shall be issued in place of any other certificate alleged to have been lost, stolen, or destroyed, except upon production of such evidence of the loss, theft or destruction and upon indemnification of the Company to such extent and in such manner as the Board of Directors may prescribe.

Section 4.—*Transfer Agents and Registrars.*

The Board of Directors shall appoint a person or persons, or any incorporated trust company or companies or both, as transfer agents and registrars and, if stock is represented by a certificate, may require that such certificate bear the signatures or the counter-signatures of such transfer agents and registrars, or either of them.

Section 5.—*Stock Ledger.*

The Company shall maintain at its principal office in Baltimore, Maryland, a stock record containing the names and addresses of all stockholders and the numbers of shares of each class held by each stockholder.

ARTICLE VII

SEAL

The Board of Directors shall provide, subject to change, a suitable corporate seal which may be used by causing it, or facsimile thereof, to be impressed or affixed or reproduced one the Company's stock certificates, bonds, or any other documents on which the seal may be appropriate.

ARTICLE VIII

AMENDMENTS

These bylaws, or any of them, may be amended or repealed, and new bylaws may be made or adopted at any meeting of the Board of Directors, by vote of a majority of the Directors, or by the stockholders at any annual meeting, or at any special meeting called for that purpose; *provided, however*, that, in the case of any amendment, repeal or replacement of Sections 3 and 6 of Article II or any part of Article IV or this Article VIII, each Independent Director must also have approved such amendment, repeal or replacement.

Exhibit 10.2

EXELON CORPORATION RETIREMENT PROGRAM

As Amended and Restated Effective January 1, 2013

EXELON CORPORATION RETIREMENT PROGRAM

INTRODUCTION

The title of this Plan shall be the "Exelon Corporation Retirement Program." This Plan is an amendment and restatement of the Commonwealth Edison Company Service Annuity System as in effect on December 30, 2001 and reflects the merger of the Service Annuity Plan of PECO Energy Company into the Plan effective December 31, 2001, and as previously amended and restated, and subsequent amendments and restatements. This amendment and restatement, except as otherwise provided herein, shall apply to Employees whose employment is terminated on or after January 1, 2013 and to the surviving spouses and surviving dependent children of such Employees. The rights and benefits of Employees whose employment terminates on or before December 31, 2012 and of the surviving spouses and surviving dependent children of such Employees shall, except as otherwise provided herein, be determined under the Plan as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time.

Subject to the foregoing, individuals who are "Participants" as defined in the document designated as the Commonwealth Edison Company Service Annuity System and attached hereto as Appendix A shall have their benefit under the Plan determined exclusively by the terms of Appendix A hereto. Individuals who are "Participants" as defined in the document designated as the Service Annuity Plan of PECO Energy Company and attached hereto as Appendix B shall have their benefit under the Plan determined exclusively by the terms of Appendix B hereto.

APPENDIX A

COMMONWEALTH EDISON COMPANY

SERVICE ANNUITY SYSTEM

Under the Exelon Corporation Retirement Program

(Amended and Restated as of January 1, 2013)

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COMMONWEALTH EDISON COMPANY

SERVICE ANNUITY SYSTEM

ARTICLE 1

ESTABLISHMENT AND PURPOSE

The title of this Plan shall be the "Commonwealth Edison Company Service Annuity System". This Plan is an amendment and restatement of the Commonwealth Edison Company Service Annuity System as in effect on December 31, 2012 and, except as otherwise provided, shall apply to Employees whose employment is terminated on or after January 1, 2013 and to the surviving Spouses and surviving dependent children of such Employees. The benefits of Employees whose employment terminates before January 1, 2013 and of the surviving Spouses and surviving dependent children of such Employees shall be determined under the Commonwealth Edison Company Service Annuity System as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time; provided, however, that the provisions of Article 7 (relating to limitations on benefits), Article 9 (relating to special rules relating to participation of and distribution to certain terminated or transferred employees), Article 10 (relating to administration), Article 13 (relating to miscellaneous provisions) and Article 15 (relating to amendment and termination of the Plan) shall be effective for all such persons.

For purposes of the Plan, the phrase "a member of IBEW Local Union 15" shall mean an employee whose terms of employment are subject to a collective bargaining agreement between IBEW Local Union 15 and his or her employer.

ARTICLE 2

DEFINITIONS

Section 2.1. Defined Terms. As used herein the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

(1) Administrator. The Company acting through its Vice President, Health & Benefits or such other person appointed pursuant to Section 10.1.

(2) Affiliate. (a) A corporation which is a member of the same controlled group of corporations (within the meaning of Section 414(b) of the Code) as an Employer, (b) a trade or business (whether or not incorporated) under common control (within the meaning of Section 414(c) of the Code) with an Employer, (c) an organization (whether or not incorporated) that is a member of an affiliated service group (within the meaning of Section 414(m) of the Code) that includes an Employer, a corporation described in clause (a) of this subdivision or a trade or business described in clause (b) of this subdivision, or (d) any other entity that is required to be aggregated with an Employer pursuant to Regulations promulgated under Section 414(o) of the Code.

(3) Annuity Starting Date. The first day on which a Service Annuity is payable to a Participant.

(4) Basic Compensation. A Participant's base pay rate per pay period, as determined by the Administrator. For purposes of the preceding sentence, a Participant's base pay rate per pay period shall include (i) any amount contributed by the Participant's Employer on behalf of such Participant for such year to the Participant's Before-Tax Contributions Account under the Exelon Corporation Employee Savings Plan, a qualified transportation fringe benefit plan described in section 132(f) of the Code, the Exelon Corporation Benefits Contribution Options or the Exelon Corporation Key Choices Program and (ii) such other types of compensation or payments as may be determined by the Administrator from time to time or as may be set forth from time to time in Exhibit 1 attached hereto, and shall exclude (i) bonuses (other than meter readers' bonuses, other bonuses included in Basic Compensation as described in Exhibit 1 and any payment for ratification of a collective bargaining agreement), (ii) overtime pay, (iii) shift premiums and (iv) such other types of compensation or payments as may be determined by the Administrator from time to time or as may be set forth from time to time in Exhibit 1 attached hereto. In the case of a Participant who is absent from employment due to either an authorized leave of absence (including a leave of absence for participation in Military Service) or employment by a union that represents any group of Employees, Basic Compensation shall mean, for the

period during which the Participant is absent due to an authorized leave of absence or employment by such union, the Participant's base pay rate per pay period in effect immediately preceding the first day of the Participant's authorized leave of absence or employment by a union, as the case may be. A Participant whose Termination of Employment occurs on account of a Total and Permanent Disability, but who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) shall not be treated as having any Basic Compensation for periods of Credited Service after such Termination of Employment. A Participant whose Termination of Employment occurs on account of a Total and Permanent Disability and who is receiving benefits under any Employer's long term disability plan shall be treated for periods of Credited Service after such Termination of Employment as having Basic Compensation determined under Section 5.2(c).

(5) Beneficiary. A Participant's Spouse or the Participant's Dependent Minor Child or Dependent Disabled Child entitled, in the event of the death of the Participant, to receive a Service Annuity, under Section 6.3 (relating to the pre-retirement surviving spouse benefit), Section 6.4 (relating to the pre-retirement surviving child benefits) or Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65). To the extent required by law and where applicable in the Plan, an alternate payee entitled to receive a Service Annuity under paragraph (b) of Section 13.2 (relating to exception to non-assignability for qualified domestic relations orders) shall also be a Beneficiary.

(6) CEG. Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the Merger Agreement).

(7) Child. A Participant's natural child born prior to the time payment of the Participant's Service Annuity commences hereunder or a child adopted by a Participant prior to the time payment of the Participant's Service Annuity commences hereunder.

(8) Code. The Internal Revenue Code of 1986, as amended.

(9) Company. Exelon Corporation, a Pennsylvania corporation, or any successor or successors.

(10) Consumer Price Index. The United States Bureau of Labor Statistics Consumer Price Index (U.S. City Average 1967 = 100). Such term shall also mean such index as it may from time to time be changed or, if it shall be discontinued, the most nearly comparable index, appropriately adjusted to yield results comparable with those which would have been produced if the index as defined in the preceding sentence had been used, as determined by the Investment Office.

(11) Corporate Investment Committee. The Company acting through the committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

(12) Credited Service. The period of a Participant's employment as an Eligible Employee which is used to compute the Participant's Service Annuity and eligibility for commencement of payment of such Service Annuity under Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms). A Participant's Credited Service includes (a) the Participant's Credited Service prior to the Effective Date determined in accordance with the provisions of the Plan as in effect prior to the Effective Date, (b) to the extent not duplicative, for a Participant who terminated employment prior to January 1, 2003, any additional service for actual employment credited to such Participant prior to the Effective Date in an Employer's employment records pursuant to Commonwealth Edison Company's service bridging policy, and (c) the period beginning on the Effective Date during which the Participant shall have been an Eligible Employee, including, (i) any period during which the Participant is in Military Service, provided that the Participant returns to the employ of an Employer within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (ii) any period during which the Participant is employed by a union that represents any group of Employees, (iii) any period for which back pay is awarded to the Participant and pursuant to which award the Participant is required to receive Credited Service under the Plan, (iv) the period following Termination of Employment on account of a Total and Permanent Disability during which the Participant is receiving benefits under any Employer's long term disability plan and (v) as and to the extent provided by resolutions of the board of directors of the Company, (1) any period of employment by Affiliates or other companies, and (2) any period of authorized absence from such employment or from employment as an Eligible Employee. A Participant's periods of Credited Service before and after a period of absence from employment that is not included in the Participant's Credited Service pursuant to the preceding sentences shall be aggregated only if (i) the Participant completes at least one year of Credited Service after such period of absence and (ii) the number of years of such period of absence from employment is less than five.

(13) Dependent Minor Child. A Child who, as of the time of the Participant's retirement or death, is under the age of 21 and qualifies as a dependent of the Participant within the meaning of Section 152 of the Code.

(14) Dependent Disabled Child. A Child who, as of the time of the Participant's retirement or death, has a permanent physical or mental disability, as certified by the medical director of the Company or by such other licensed physician designated by the Administrator, that causes such Child to be unable to engage in substantial gainful employment, and is a dependent of the Participant within the meaning of Section 152 of the Code (determined by disregarding any age limitation contained in Section 152 of the Code).

(15) Earnings. The Participant's earnings during the Participant's period of Credited Service on and before December 25, 1994 determined in accordance with the provisions of the Plan as in effect prior to April 1, 1995.

(16) Effective Date. Except as otherwise specifically provided herein, the Effective Date of this amendment and restatement of the Plan with respect to the Company and any other entity that was an Employer on December 31, 2012 shall be January 1, 2012 and in the case of any other Employer shall be the date designated by such Employer.

(17) Eligible Employee. (a) Any Employee who was an Eligible Employee on December 31, 2000, and who is receiving regular salary or wages from and rendering services to an Employer, or any such individual who is on an authorized leave of absence, and (b) on or after January 1, 2001, any Employee whose first Hour of Service with an Employer is prior to January 1, 2009 and who (i) is a member of IBEW Local Union 15 who becomes initially employed at a facility that, as of October 19, 2000, was owned by Commonwealth Edison Company, Unicom Corporation or any affiliate of Unicom Corporation, (ii) elects to participate in this Plan and (iii) is either receiving regular salary or wages from and rendering services to an Employer, or is on an authorized leave of absence; but, in either case excluding (i) an Employee the terms of whose employment are subject to a collective bargaining agreement that does not provide for participation in this Plan, (ii) an Employee paid on the temporary payroll of an Employer who has never completed at least 1,000 Hours of Service in any period of twelve consecutive months beginning with the Employee's date of hire or anniversary thereof, (iii) an Employee who executes a written waiver of his or her right to participate in the Plan; (iv) an individual who performs services for an Employer, pursuant to an agreement (written or oral) that classifies such individual's relationship with the Employer as other than an Employee regardless of whether such individual is at any time determined to be an Employee; (v) on or after the Effective Time, an individual who was employed immediately prior to the Effective Time (as such term is defined in the Merger Agreement) at CEG or a facility owned immediately before the Effective Time by CEG and (vi) an individual who is newly employed on or after the Effective Time (as such term is defined in the Merger Agreement) at a facility owned immediately before the Effective Time by CEG. Notwithstanding anything contained in the Plan to the contrary, any Employer may, at the time such Employer elects to participate in this Plan in the manner described in Section 11.1 (relating to adoption of the Plan), designate, with the consent of the Company, a specified group of Employees who will be Eligible Employees. In the case of Unicom Thermal Technologies Inc. ("Unicom Thermal"), the term "Eligible Employee" shall mean only those persons rendering service to Unicom Thermal who (i) formerly were employed by the Company, (ii) transferred from the employment of the Company to the employment of Unicom Thermal at the request of the Company, (iii) are

otherwise described in the definition of Eligible Employee set forth in this subdivision (16) and (iv) completed at least ten years of Credited Service under the Plan at the time of transfer from the employment of the Company to the employment of Unicom Thermal; provided, however, any such Employee who had at least eight years of Credited Service at the time of such transfer shall continue to be an Eligible Employee in the Plan until such Employee completes ten years of Credited Service. In the case of any individual who, as of December 31, 2000, was an Employee of Commonwealth Edison Company and who subsequently transfers employment to employment with the Exelon Power Team, such individual shall remain an Eligible Employee through the second anniversary of the date of such transfer of employment, and shall not thereafter be an Eligible Employee. Notwithstanding the preceding sentence, an individual who, as of December 31, 2000, was an Employee of Commonwealth Edison Company and who transferred employment to employment with the Exelon Power Team shall be an Eligible Employee as of January 1, 2004, and, without limiting the preceding clause, an individual who transfers employment from employment with an Employer to employment with the Exelon Power Team during 2003 and who was an Eligible Employee immediately prior to such transfer shall continue to be an Eligible Employee until December 31, 2003 and each individual who transfers employment from the Exelon Power Team to an Employer during 2003 shall not be an Eligible Employee prior to January 1, 2004. In the case of Exelon Services Inc., the term "Eligible Employee" shall be limited to those Employees of Exelon Services Inc. who were on the payroll of Unicom Energy Solutions as of April 1, 2001 and are otherwise Eligible Employees. Notwithstanding anything contained herein to the contrary, an Eligible Employee shall not include an individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 6.9 (relating to Special Lump Sum Payment Option).

(18) Employee. An individual whose relationship with an Employer is, under common law, that of an employee.

(19) Employer. The Company and any other Affiliate set forth on Appendix I hereto that, with the consent of the Company, elects to participate in the Plan in the manner described in Section 11.1 (relating to adoption of the Plan) either with respect to all Employees or a specified group of Employees of such Affiliate and any successor Affiliate that adopts this Plan pursuant to Article 12 (relating to continuance by a successor). If any entity described in the preceding sentence withdraws from participation in the Plan pursuant to Section 15.3 (relating to termination of the Plan by an Employer), such entity shall thereupon cease to be an Employer. Appendix I shall be updated from time to time by the Company to reflect any adoption pursuant to Section 11.1, but the failure to so update such Appendix shall not affect the effectiveness of any such adoption. Such adoptions will be effective whether occurring before, on or after the Effective Date and whether or not reflected in Appendix I.

(20) ERISA. The Employee Retirement Income Security Act of 1974, as amended.

(21) Federal Benefit. The annual amount of full old age benefits which would be payable to the Participant under the Federal Social Security Act at the age at which full old age benefits would be payable to such Participant under such Act. Except as provided in the following sentence, the amount of the Federal Benefit and the age at which full old age benefits become payable shall be determined as of December 25, 1994 in accordance with the provisions of the Plan as in effect on such date. Notwithstanding the preceding sentence, solely for purposes of Section 5.6 (relating to Federal Benefit supplemental payments), the amount of Federal Benefit and the age at which full old age benefits become payable shall be determined at the time of a Participant's Termination of Employment by using the terms of the Federal Social Security Act as in effect at such time. For purposes of the preceding sentence, the amount of Federal Benefit shall be computed (a) with respect to a member of IBEW Local Union 15 whose Termination of Employment occurs on or after January 1, 2011, by using the Participant's compensation subject to tax under the Federal Insurance Contributions Act (other than the Medicare portion), and (b) with respect to any other Participant, by using an estimated wage history determined by applying a salary scale based on the actual change in the average national wage from year to year as determined by the Social Security Administration, projected backwards, to the Participant's compensation subject to tax under the Federal Insurance Contributions Act (other than the Medicare portion) for the calendar year ending immediately prior to the Participant's Termination of Employment. Notwithstanding the preceding sentence, in no event shall a Participant's Federal Benefit be greater than the Federal Benefit determined by using a wage history that assumes the Participant earned no compensation for periods prior to employment with the Company and Affiliates and uses actual compensation paid by the Company and Affiliates for periods of employment with the Company and Affiliates and, in the case of a Participant who is absent from employment due to employment by a union that represents any group of Employees, uses actual compensation paid by such union for periods of employment with such union

(22) Highest Average Annual Pay. The sum of a Participant's average annual Basic Compensation and Incentive Pay (a) with respect to any Participant who, as of the date of the Participant's Termination of Employment, is not a member of IBEW Local Union 15, during the four consecutive years (104 biweekly pay periods), and (b) with respect to any Participant who, as of the date of the Participant's Termination of Employment, is a member of IBEW Local Union 15, during which such average annual Basic Compensation and Incentive Pay was the highest, or (c) during all years of the Participant's Credited Service if such Credited Service is less than 104 or 78 biweekly pay periods, as applicable. In determining whether a Participant has 104 or 78 consecutive biweekly pay periods, as applicable, any period of uncompensated absence from employment with an Employer, other than an absence due to participation in Military Service shall be disregarded. In computing "Highest Average Annual Pay," the total of

the Basic Compensation and Incentive Pay for a Participant for the applicable consecutive pay periods shall be multiplied, in the case of 104 pay periods by 0.25068654 and in the case of 78 pay periods by 0.33424872; provided, that in the case of a Participant whose years of Credited Service include fewer than 104 or 78 pay periods, as applicable, the multiplier shall be a fraction the numerator of which is one and the denominator of which is the quotient of (a) the number of 14-day periods during each 365-day period (or if less, during the Participant's Credited Service) and (b) the number of pay periods during the Participant's years of Credited Service. In addition, notwithstanding anything herein to the contrary, in computing an Employee's Highest Average Annual Pay, the aggregate amount of the Employee's Basic Compensation and Incentive Pay in excess of the following limits shall not be taken into account: (i) for Plan Years ending before January 1, 1996, $200,000 (as adjusted for increases in the cost of living pursuant to Section 415(d) of the Code for the year in which the computation of Basic Compensation and Incentive Pay is being made), (ii) for Plan Years beginning on or after January 1, 1996 and before January 1, 2002, $150,000 (adjusted for increases in the cost of living in accordance with Section 401(a)(17) of the Code), and (iii) for all Plan Years beginning on or after January 1, 2002, $200,000 (adjusted for increases in the cost of living in accordance with Section 401(a)(17) of the Code). For purposes of the preceding sentence, the limit determined with respect to clause (i) for the last year for which the computation is made shall be applied for such year and all preceding years. For Plan Years beginning before January 1, 1997, the Basic Compensation and Incentive Pay of an Employee who is a 5% owner of Commonwealth Edison Company or any Affiliate or one of the ten employees of Commonwealth Edison Company and all Affiliates who was paid the greatest compensation (as defined in Section 415 of the Code) for the Plan Year shall include the Basic Compensation and Incentive Pay of the Employee's spouse and any lineal descendants of the Employee who have not attained age 19 before the close of the Plan Year.

(23) Hour of Service. (a) Each hour for which an Employee is paid, or entitled to payment, for the performance of duties (such hours to be credited to the Employee for the computation period or periods in which the duties are performed); (b) each hour for which an Employee is paid, or entitled to payment, on account of a period of time during which no duties are performed (irrespective of whether a Termination of Employment has occurred) due to vacation, holiday, illness, incapacity (including disability), layoff, jury duty, military duty or leave of absence (such hours to be credited to the Employee for the computation period or periods in which the period of time during which no duties are performed occurs); and (c) each hour for which back pay, irrespective of mitigation of damages, is either awarded or agreed to by an Employer (such hours to be credited to the Employee for the computation period or periods in which the award or agreement pertains rather than the computation period in which the award, agreement or payment is made). Hours of Service shall be computed in accordance with paragraphs (b) and (c) of Section 2530.200b-2 of the Department of Labor Regulations.

(24) Incentive Pay. The payments, if any, earned by the Participant with respect to each year of Credited Service after 1994, regardless of when paid, under the plans set forth in Exhibit 2 attached hereto. Incentive Pay shall also include with respect to each year of Credited Service commencing after December 31, 2002, lump sum merit increases paid during such year of Credited Service. In the case of a Participant who is absent from employment due to employment by a union that represents any group of Employees, Incentive Pay shall mean, for the period during which the Participant is absent from employment, the payments the Participant would have received under the applicable plan set forth in Exhibit 2 attached hereto, as determined by the union employing such Participant.

(25) Investment Office. The Company acting through the Exelon Investment Office.

(26) Merger Agreement. That Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc

(27) Military Service. The performance of duty on a voluntary or involuntary basis in a "uniformed service" (as defined below) under competent authority of the United States government and includes active duty, active duty for training, initial active duty for training, inactive duty training, full-time National Guard duty, and a period for which a person is absent from employment for the purpose of an examination to determine the fitness of the person to perform any such duty. For purposes of the preceding sentence, the term "uniformed service" means the Armed Forces, the Army National Guard and the Air National Guard when engaged in active duty for training, inactive duty training, or full-time National Guard duty, the commissioned corps of the Public Health Service, and any other category of persons designated by the President of the United States in time of war or emergency.

(28) Normal Retirement Age. A Participant's 65th birthday.

(29) Participant. An Employee described in Article 3 (relating to participation). An individual shall cease to be a Participant upon the date the individual is no longer eligible to receive a benefit from this Plan (including, without limitation, upon his or her receipt of a Special Lump Sum Payment as defined in Section 6.9 (relating to Special Lump Sum Payment Option)) or upon the individual's Termination of Employment if the individual has not completed at least five years of Vesting Service upon the date of his or her Termination of Employment and is not otherwise eligible to receive a benefit from this Plan.

(30) Plan. The Plan herein set forth, as from time to time amended, which is part of the Exelon Corporation Retirement Program.

(31) Plan Year. The calendar year.

(32) Regulations. Written promulgations of the Department of Labor construing Title I of ERISA or the Internal Revenue Service construing the Code.

(33) Retiree. A Participant or Beneficiary receiving a Service Annuity.

(34) Service Annuity. The amount payable to a Retiree from the Service Annuity Fund under the Plan. Except as otherwise indicated by the context, such term includes an annuity payable pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), Section 6.2 (relating to optional Service Annuity forms), Section 6.3 (relating to surviving spouse annuities, Section 5.6 (relating to Federal Benefit supplemental payments), Section 5.7 (relating to deferred vested termination) and Section 6.4 (relating to a surviving Child annuity). Notwithstanding the foregoing, a Participant shall not be entitled to any amount payable from the Service Annuity Fund under the Plan following the Participant's receipt of a Special Lump Sum Payment within the meaning of Section 6.9 (relating to Special Lump Sum Payment Option).

(35) Service Annuity Fund. All money and property of every kind held by the Trustee under the Trust Agreement.

(36) Spouse. The individual who is the husband or wife of a Participant as the result of a legal union between one man and one woman, within the meaning of the Defense of Marriage Act, on the Participant's Pension Starting Date, or if earlier, on the date of the Participant's death. While the Spouse is living and, except as otherwise provided in a qualified domestic relations order as described in paragraph (b) of Section 13.2 (relating to exception to nonassignability in the case of a qualified domestic relations order) or paragraph (c) of Section 6.6 (relating to automatic cancellation of elections), such Spouse shall be treated as the Participant's Spouse for all purposes of this Service Annuity System without regard to whether such Spouse remains married to the Participant after the Participant's Annuity Starting Date.

(37) Termination of Employment. A Participant's ceasing to be an Employee of any Employer or any Affiliate. A transfer between employment by an Employer and employment by an Affiliate or between employment by Employers or Affiliates shall not constitute a Termination of Employment.

(38) Total and Permanent Disability. A disability which, in the opinion of the Administrator, renders the Participant unable to perform the principal duties of the Participant's regular job classification or such other job classification as may be made available to the Participant by an Employer or an Affiliate and which results from a cause other than one or more of the following, as determined by the Administrator, in its sole discretion:

(i) excessive or habitual use of drugs, intoxicants, narcotics or alcohol;

(ii) injury or disease sustained while participating in illegal activities; or

(iii) injury or disease sustained while employed by another Employer and arising out of such other employment.

(39) Trust Agreement. The agreement between the Company and the Trustee governing the Service Annuity Fund.

(40) Trustee. The trustee of the Service Annuity Fund or, if there shall be more than one trustee acting at any time, all of such trustees collectively.

(41) Vesting Service. The period of an Employee's employment which is used to determine whether the Employee is entitled to receive a Service Annuity under Article 5 (relating to Service Annuities). An Employee's Vesting Service includes (a) the Participant's vesting service prior to the Effective Date determined in accordance with the provisions of the Plan as in effect prior to the Effective Date, (b) to the extent not duplicative, for an Employee who terminated prior to January 1, 2003, any additional service for actual employment credited to such Employee prior to the Effective Date in an Employer's employment records pursuant to Commonwealth Edison Company's service bridging policy and (c) the aggregate of the periods beginning on or after the Effective Date during which the Employee is employed by an Employer or an Affiliate, provided that in the case of an Employee who has no vested right to any benefits under this Plan, such Employee's periods of Vesting Service before and after a period of absence from employment shall be aggregated only when the Employee's number of consecutive one-year periods of absence from employment is less than five and the Employee has at least one year of Vesting Service after such period of absence from employment. For purposes of the preceding sentence, an Employee shall be deemed to be employed by an Employer or an Affiliate during (a) any period of absence from employment by an Employer or an Affiliate which is of less than twelve months' duration, (b) the first twelve months of any period of absence from employment for any reason other than the Employee's quitting, retiring or being discharged, except as provided in clause (f) below, (c) any period during which the Employee is in Military Service, provided that the Employee returns to the employ of an Employer or an Affiliate within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (d) any period, whether less than or greater than twelve months, during which the Participant is employed by a union that represents any group of Employees, (e) the period following Termination of Employment on account of a Total and Permanent Disability during which the Participant is receiving benefits under any Employer's long term disability plan and (f) as and to the extent provided by resolutions of the board of directors of the Company, any period of authorized absence from employment as an Eligible Employee. The Administrator may require certification from an Employee, as a condition of granting Vesting Service under this subdivision (39), that the leave was taken for one of the reasons enumerated in the preceding sentence. Notwithstanding the preceding sentences, in

determining an Employee's period of absence from employment by an Employer or an Affiliate, the following shall be disregarded: the first twenty-four months of any period of absence from employment by reason of (i) the Employee's pregnancy, (ii) the birth of the Employee's child, (iii) the placement of a child with the Employee in connection with the adoption of such child by such Employee or (iv) caring for such child for a period beginning immediately following such birth or placement.

Section 2.2. Gender and Plurals. Wherever used in this Plan, words in the masculine gender shall include masculine or feminine gender, and, unless the context otherwise requires, words in the singular shall include the plural, and words in the plural shall include the singular.

Section 2.3. Definition of "Highly Compensated Employee". Wherever applicable for purposes of satisfying legal requirements applicable to the Plan, the term "highly compensated employee" shall mean any Employee who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q)(1)(B)(ii) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its Affiliates when ranked on the basis of compensation paid during such preceding Plan Year.

ARTICLE 3

PARTICIPATION

Section 3.1. Employees Represented by IBEW Local Union 15. Each Eligible Employee who is a member of a collective bargaining unit represented by IBEW Local Union 15 and who was a Participant in the Plan on December 31, 2000 shall continue to be a Participant as of January 1, 2001. Each other Eligible Employee who is a member of IBEW Local Union 15 shall become a Participant as of the first day that such Eligible employee completes an Hour of Service with an Employer as an Eligible Employee, provided that such Eligible Employee does not elect, in the time and manner prescribed by the Administrator for such an election, to participate in the Exelon Corporation Pension Plan for Bargaining Unit Employees. Notwithstanding the foregoing, effective January 1, 2009, an Employee who is a member of a collective bargaining unit represented by IBEW Local Union 15 and whose first Hour of Service with an Employer is on or after January 1, 2009 shall not be an Eligible Employee and shall not be eligible to become a Participant at any time.

Section 3.2. Management Employees. (a) In General. Each Participant who is not a member of a collective bargaining unit represented by IBEW Local Union 15 and who is, as of January 1, 2002, an Eligible Employee shall be permitted to elect, in the time and manner prescribed by the 'Committee', as such term was defined in the Plan prior to June 1, 2006, to either (i) continue participating in the Plan on and after January 1, 2002 or (ii) cease participating in the Plan as of December 31, 2001 and begin participating in the Exelon Corporation Cash Balance Pension Plan as of January 1, 2002. Each Eligible Employee who elects to continue participating in the Plan or who is offered and fails to make any such election shall continue to be a Participant as of January 1, 2002. Each Eligible Employee who elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participation in this Plan shall cease participation in the Plan as of December 31, 2001 and shall not be entitled to any benefit under the Plan, unless such Participant receives a notification (the "Notice") from an Employer that his or her employment with the Employers and their Affiliates will be terminated on or before December 31, 2002 and that such Participant is eligible for severance benefits under the Exelon Corporation Merger Separation Plan for Designated Management Employees or any other severance plan maintained by an Employer or an Affiliate. An Eligible Employee who receives a Notice shall continue to be a Participant in the Plan until his or her Termination of Employment, notwithstanding such Eligible Employee's election to participate in the Exelon Corporation Cash Balance Pension Plan. An Eligible Employee (i) who receives a Notice, but whose employment does not terminate on or before December 31, 2002, or (ii) whose employment terminates before December 31, 2002 without the Employee receiving a Notice shall cease participation in the Plan as of December 31, 2001 if such Employee elects, in the time and manner prescribed by the 'Committee', as such term was defined in the Plan prior to June 1, 2006, to participate in the Exelon Corporation Cash Balance Pension Plan.

Effective as of January 1, 2004, each Eligible Employee (i) who is an employee of the Exelon Power Team, (ii) who, as of December 31, 2000, was an Employee of Commonwealth Edison Company and is, as of January 1, 2004, an Eligible Employee, (iii) who was, at any time prior to January 1, 2004, a Participant and (iv) who did not previously make a valid election pursuant to the preceding paragraph shall be permitted to elect, in the time and manner prescribed by the 'Committee', as such term was defined in the Plan prior to June 1, 2006, to either (A) resume or continue participation in the Plan as of January 1, 2004 or (B) participate in the Exelon Corporation Cash Balance Pension Plan as of January 1, 2004. Each such Eligible Employee who affirmatively elects to resume or continue participation in the Plan in lieu of participation in the Exelon Corporation Cash Balance Pension Plan shall resume or continue participation in this Plan as of January 1, 2004.

(b) Transfer of Benefits and Assets to Cash Balance Pension Plan . If an Eligible Employee described in paragraph (a) above elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participating in the Plan, the Employee's Service Annuity, determined as of December 31, 2001, or December 31, 2003, as the case may be, based on the Employee's Credited Service and Highest Annual Average Pay as of such date but without giving effect to Section 5.6, shall be transferred to the Exelon Corporation Cash Balance Pension Plan and such Employee shall not accrue any additional benefit under the Plan. An amount of assets that is equal to the present value of the Participant's Service Annuity described in the preceding sentence, determined using the methods and assumptions prescribed by Section 4044 of ERISA, shall also be transferred to the Exelon Corporation Cash Balance Pension Plan. Such transfer of benefits and assets related thereto shall occur as soon as administratively practicable after the Eligible Employee makes the election described in paragraph (a) above. In the event that an Eligible Employee whose Service Annuity and related assets are transferred to the Exelon Corporation Cash Balance Pension Plan receives a Notice and has a Termination of Employment on or before December 31, 2002, the Service Annuity and related assets that were transferred to the Exelon Corporation Cash Balance Pension Plan shall be transferred back to the Plan and the amount of the pension benefit accrued by such Employee during 2002 (if any) shall be determined under the terms of this Plan rather than the Exelon Corporation Cash Balance Pension Plan. Such transfer shall occur as soon as administratively practicable.

Section 3.3. Cessation of Participation. An individual's participation in the Plan shall cease upon the date the individual is no longer eligible to receive a benefit from this Plan or upon the individual's Termination of Employment if the individual has not completed at least five years of Vesting Service upon the date of his or her Termination of Employment and is not otherwise eligible to receive a benefit from this Plan.

Section 3.4. Certain Rehired Employees. Notwithstanding anything contained herein to the contrary, no Employee who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 6.9 (relating to Special Lump Sum Payment Option) shall be eligible to become a Participant pursuant to this Article 3.

ARTICLE 4

CONTRIBUTIONS

Section 4.1. Amount of Contributions. The Employers intend to make contributions to the Service Annuity Fund of amounts which, in the aggregate over a period of time, are sufficient to finance the benefits provided by the Plan. All such contributions shall be in such amounts and shall be made in such manner and at such time as the Company shall from time to time determine in accordance with the funding policy it establishes and consistent with minimum funding standards under Section 412 of the Code. the Company may rely on the advice of actuaries in establishing and carrying out a funding policy. Forfeitures arising under the Plan for any reason shall be applied to reduce the cost of the Plan, not to increase the Service Annuities payable to Participants, Beneficiaries or Retirees.

Section 4.2. Return of Contributions. Any contribution made to the Service Annuity Fund by an Employer by reason of a good faith mistake of fact, or any contribution made to the Service Annuity Fund by an Employer which exceeds the maximum amount for which a deduction is allowable to the Employer for federal income tax purposes by reason of a good faith mistake in determining the maximum deductible amount, shall upon the request of the Employer be returned by the Trustee to the Employer. The Employer's request and the return of any such contribution must be made within one year after such contribution was mistakenly made or after the deduction of such excess portion of such contribution was disallowed, as the case may be. The amount to be returned to the Employer pursuant to this Section 4.2 shall be the excess of (a) the amount contributed over (b) the amount that would have been contributed had there not been a mistake of fact or a mistake in determining the maximum allowable deduction. Earnings attributable to the amount contributed by mistake shall not be returned to the Employer, but losses attributable thereto shall reduce the amount so returned.

ARTICLE 5

SERVICE ANNUITIES

Section 5.1. Description of Service Annuities. Each Participant whose Termination of Employment occurs on or after his or her Normal Retirement Age shall be entitled to a Service Annuity as described in Section 5.2 (relating to normal and deferred retirement). Each Participant whose Termination of Employment occurs prior to the Participant's 65th birthday but after the Participant has completed at least ten years of Credited Service and has attained age 50 shall be entitled to a Service Annuity as described in Section 5.3 (relating to early retirement). Each Participant whose Termination of Employment occurs on or after the Participant's 45th birthday on account of a Total and Permanent Disability shall be entitled to a Service Annuity as described in Section 5.4 (relating to disability retirement at or after age 45), provided such Participant has satisfied the conditions set forth in Section 5.4. Each Participant who has completed at least ten years of Credited Service and whose Termination of Employment occurs prior to the Participant's 45th birthday on account of Total and Permanent Disability shall be entitled to a Service Annuity as described in Section 5.5 (relating to disability retirement before age 45), provided such Participant has satisfied the conditions set forth in Section 5.5. Each Participant whose Termination of Employment occurs after the Participant has completed at least five years of Vesting Service but who is not described in any of the preceding sentences shall be entitled to a Service Annuity described in Section 5.7 (relating to deferred vested termination).

Section 5.2. Normal and Deferred Retirement. (a) In General. Each Participant whose Termination of Employment occurs on or after the Participant's Normal Retirement Age shall be entitled, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing on the Service Annuity payment date immediately following the day the Participant's status on the Human Resource system of the Company is changed to "inactive." The annual amount of such Service Annuity shall equal, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), the sum of the amounts described in subparagraphs (A), (B) and (C) below:

(A) 1.25% of the Participant's Earnings, reduced by 25% (less 1% for each year, if any, by which the Participant's years of Credited Service as of December 25, 1994 are less than 35, computed to the nearest full year) of the Participant's Federal Benefit, determined as of December 25, 1994.

(B) 1.60% (1.62% for Participants who terminate employment on or after October 1, 2008 and were a member of a collective bargaining unit represented by IBEW Local Union 15 immediately prior to termination of employment) of the Participant's Highest Average Annual Pay, multiplied by the number of years of the Participant's Credited Service (not in excess of 40 years).

(C) 0.5% of the Participant's Highest Average Annual Pay, multiplied by the number of years, if any, by which the Participant's years of Credited Service (not in excess of 40) exceed the limitation on the number of years of Credited Service taken into account under subparagraph (B) of paragraph (a) of this Section 5.2.

Notwithstanding the preceding, the annual amount of the Service Annuity for a Participant who has at least 10 years of Credited Service shall not be less than the applicable amount stated in Table A.

(b) Special Rule for Participants Who Attain Age 70-½ While Employed. If a Participant remains employed by an Employer or an Affiliate beyond April 1 of the year following the year in which the Participant attains age 70-½, distribution of such Participant's Service Annuity (i) shall commence, in the case of a Participant who is a 5-percent owner as defined in Section 416(i) of the Code, or (ii) may commence, upon any other such Employee's election, in either case, not later than April 1 next following the calendar year in which the Participant attains age 70-½.

The annual amount of the Participant's Service Annuity that commences under the preceding paragraph shall be recomputed pursuant to this Section 5.1 (relating to normal and deferred retirement) as of each succeeding April 1 to reflect any increase in the Participant's Credited Service and Highest Average Annual Pay attributable to the Participant's employment since the preceding April 1.

Notwithstanding anything in the Plan to the contrary, the form and timing of all distributions under the Plan to any Participant shall be in accordance with Section 401(a)(9) of the Code and regulations issued thereunder, including the incidental death benefit requirements of Section 401(a)(9)(G) of the Code and Treasury Regulation §1.401(a)(9)-2 through Treasury Regulation §1.401(a)(9)-9.

(c) Basic Compensation for Participant with Total and Permanent Disability. In the case of a Participant whose Termination of Employment is on account of a Total and Permanent Disability and who is entitled to a Service Annuity under either paragraph (b) of Section 5.4 (relating to disability retirement at or after age 45 for management Employees) or paragraph (b) of Section 5.5 (relating to disability retirement before age 45 for management Employees), Basic Compensation shall mean, for the period following the Participant's

Termination of Employment and during which the Participant is receiving benefits under any Employer's long term disability plan, the Participant's base pay rate per pay period in effect immediately preceding the first day of the Participant's absence due to such Total and Permanent Disability increased each October 1 following the Participant's Termination of Employment at a rate equal to the cost of living adjustment described in the following sentence. For purposes of the preceding sentence, the cost of living adjustment shall equal, for each October 1, the percentage by which the Consumer Price Index for the July immediately preceding such October 1 exceeds the Consumer Price Index for the July immediately preceding the twelve month period beginning October 1 in which the Participant's Termination of Employment occurred; provided, however, that:

(i) If, as of such October 1, there shall be no such excess, the adjustment percentage shall be deemed to be zero for the twelve-month period beginning on such October 1.

(ii) There shall be no negative adjustment percentage.

(iii) The aggregate adjustment percentage for any twelve-month period beginning October 1 shall never be lower than the aggregate adjustment percentage for the preceding such period.

(iv) If the percentage increase in the Consumer Price Index computed for the twelve-month period beginning on October 1 does not exceed the aggregate adjustment percentage for the preceding twelve-month period by at least three percentage points, the aggregate adjustment percentage for the preceding twelve-month period shall continue in effect during such twelve-month period beginning on October 1.

(v) The aggregate adjustment percentage for any twelve-month period beginning on October 1 shall not be more than seven percentage points greater than that for the preceding twelve-month period. If the aggregate adjustment percentage for any twelve-month period beginning on October 1 exceeds by more than seven percentage points the aggregate adjustment percentage for the preceding twelve-month period, the excess shall be carried over to succeeding twelve-month periods until such excess is reduced to zero.

(vi) The adjustment percentage for the twelve-month period beginning with the October 1 next following the date the Participant's Termination of Employment occurs shall be the adjustment percentage determined in accordance with the preceding provisions of this Section 5.2(c) multiplied by a fraction the numerator of which shall be the number of full calendar months between such date and such October 1 and the denominator of which shall be twelve.

The adjustment described in this Section 5.2(c) shall continue to be made unless and until the Participant ceases to be eligible to receive benefits under any Employer's long term disability plan. Notwithstanding the preceding sentence, if a Participant returns to employment with any Employer and ceases to be eligible to receive benefits under any Employer's long term disability plan but again becomes eligible to receive such benefits as a continuation of the same Total and Permanent Disability, as determined under the provisions, or interpretations, of the Employer's long term disability plan, the adjustments described in this Section 5.2(c) shall continue to be made as though the Participant had never ceased to be eligible for such benefits, provided that an adjustment shall be made for any earnings received by the Participant while the Participant was employed by any Employer.

Section 5.3. Early Retirement. Each Participant whose Termination of Employment occurs prior to the Participant's 65th birthday but after the Participant has completed at least ten years of Credited Service and has attained age 50 shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive an early retirement Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Participant attains age 65. The annual amount of such early retirement Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in the case of termination or curtailment) be the amount computed pursuant to Section 5.2 (relating to normal and deferred retirement) multiplied by the applicable factor (determined with reference to the Participant's attained age at the time benefits commence to be paid) from (a) with respect to any Participant who is not a member of IBEW Local Union 15, Table B, and (b) with respect to any Participant who is a member of IBEW Local Union 15, Table B-1.

Section 5.4. Disability Retirement at or After Age 45 . (a) Rules Applicable to Union Employees . Each Eligible Participant (as defined in the following paragraph) whose Termination of Employment occurs on or after the Eligible Participant's 45th birthday on account of a Total and Permanent Disability and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement) or Section 5.3 (relating to early retirement) shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), without regard to the number of the Eligible Participant's years of Credited Service, to receive a disability Service Annuity payable in semi-monthly payments for the Eligible Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Eligible Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Eligible Participant attains age 65. The annual amount of such disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the amount computed pursuant to Section 5.3 (relating to early retirement), except that if the Eligible Participant's employment terminated on account of a Total and Permanent Disability prior to the Eligible Participant's 55th birthday, the Eligible Participant shall be treated as though he or she attained age 55 for purposes of determining the applicable factor from Table B.

For purposes of this Section 5.4, an “Eligible Participant” shall mean a Participant who, at the time the Participant’s employment terminates, is a member of Local Union 15, International Brotherhood of Electrical Workers.

(b) Rules Applicable to Management Employees . Each Participant who is a management Employee, whose Termination of Employment occurs on or after the Participant’s 45th birthday on account of a Total and Permanent Disability and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement) or Section 5.3 (relating to early retirement) shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), without regard to the number of the Participant’s years of Credited Service, to receive a disability Service Annuity payable in semi-monthly payments for the Participant’s lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Participant’s status on the Human Resource system of the Company is changed to “inactive”, provided that such Participant (i) shall have qualified for and received long-term disability benefits under the Exelon Corporation Disability Benefit Plan for Management Employees (the “LTD Plan”), (ii) shall be eligible to receive Social Security benefits on account of such disability and (iii) shall no longer be eligible to receive benefits under the LTD Plan because such benefits have been exhausted. In no event shall the semi-monthly payments described in the preceding sentence commence later than the later of (a) the Service Annuity payment date coinciding with or immediately following the date the Participant attains age 65 and (b) the date the Participant ceases to be eligible to receive benefits under the

LTD Plan because such benefits have been exhausted. The annual amount of such disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the amount computed pursuant to Section 5.3 (relating to early retirement), except that if the Participant's employment terminated on account of a Total and Permanent Disability prior to the Participant's 55th birthday, the Participant shall be treated as though he or she attained age 55 for purposes of determining the applicable factor from Table B.

Section 5.5. Disability Retirement Before Age 45 . (a) Rules Applicable to Union Employees . Each Eligible Participant (as defined in the following paragraph) who has completed at least 10 years of Credited Service and whose Termination of Employment occurs prior to the Eligible Participant's 45th birthday on account of a Total and Permanent Disability shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a reduced disability Service Annuity payable in semi-monthly payments for the Eligible Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Eligible Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Eligible Participant attains age 65. The annual amount of such reduced disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the sum of (a) the amount computed pursuant to Section 5.4 (relating to disability retirement at or after age 45) plus (b) the excess, if any, of (i) 25% of the Eligible

Participant’s Highest Average Annual Pay over (ii) the sum of the annual amount computed under Section 5.4 (relating to disability retirement at or after age 45) plus the aggregate annual amount of the Federal Benefit supplemental payments payable to such Eligible Participant pursuant to Section 5.6 (relating to the Federal Benefit supplemental payments).

For purposes of this Section 5.5, an “Eligible Participant” shall mean a Participant who, at the time the Participant’s employment terminates, is a member of Local Union 15, International Brotherhood of Electrical Workers.

(b) Rules Applicable to Management Employees . Each Participant who is a management Employee, who has completed at least 10 years of Credited Service and whose Termination of Employment occurs prior to the Participant’s 45th birthday on account of a Total and Permanent Disability shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a reduced disability Service Annuity payable in semi-monthly payments for the Participant’s lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Participant’s status on the Human Resource system of the Company is changed to “inactive” and no later than the Service Annuity payment date coinciding with or immediately following the date the Participant attains age 65 provided, that such Participant (i) shall have qualified for and received long-term disability benefits under the LTD Plan, (ii) shall be eligible to receive Social Security benefits on account of such disability and (iii) shall no longer be eligible to receive benefits under the LTD Plan because such benefits have been exhausted. The annual amount of such reduced disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the sum of (a) the amount computed pursuant to Section 5.4 (relating to disability retirement at or after age 45) plus (b) the excess, if any, of (i) 25% of the Participant's Highest Average Annual Pay over (ii) the sum of the annual amount computed under Section 5.4 (relating to disability retirement at or after age 45) plus the aggregate annual amount of the Federal Benefit supplemental payments payable to such Participant pursuant to Section 5.6 (relating to the Federal Benefit supplemental payments).

Section 5.6. Federal Benefit Supplemental Payments Prior to Age 65 . Each Participant whose Service Annuity is computed pursuant to Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) and which commences prior to the Participant's attainment of age 65 shall receive supplemental monthly payments each in an amount equal to 80% of the amount of the Participant's monthly Federal Benefit and, except in the case of a Participant whose Service Annuity is computed under Section 5.5 (relating to disability retirement before age 45), shall have his or her Service Annuity reduced by an amount equal to the product of (a) the aggregate annual amount of such supplemental monthly payments multiplied by (b) the applicable factor (determined with reference to the Participant's attained age at the time benefits commence to be paid) from (i) with respect to any Participant who is not a member of IBEW Local Union 15, Table B-2, and (ii) with respect to any Participant who is a member of IBEW Local Union 15, Table B-3.

Section 5.7. Deferred Vested Termination. Each Participant whose Termination of Employment occurs after the Participant has completed at least five years of Vesting Service and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) shall be entitled, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a deferred Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing as soon as practicable after the date elected, in the manner prescribed by the Administrator, by the Participant but not earlier than the later of (i) the day the Participant's status on the Human Resource system of the Company is changed to "inactive" and (ii) the Participant's 60th birthday or, in the case of a Participant who completed at least ten years of Credited Service, the Participant's 50th birthday. The annual amount of such deferred Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the amount computed under Section 5.2 (relating to normal and deferred retirement) multiplied by the applicable factor from Table F to reflect the Participant's age, if less than 65, at the date upon which payment of the Participant's deferred Service Annuity commences. In no event shall a Participant's election hereunder to begin receiving payment of his or her Service Annuity permit such payments to begin later than April 1 of the calendar year following the calendar year in which the Participant attains age 70- ½. Notwithstanding anything herein to the contrary, if a Participant entitled to a deferred Service Annuity under this Section 5.7 fails to make an election to begin receiving his or her deferred Service Annuity, payment of the Participant's Service Annuity shall commence no later than 60 days following the Plan Year in which the Participant attains age 65.

Each Participant whose employment is terminated before the Participant completes at least five years of Vesting Service and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) shall be entitled to no benefits whatsoever under this Plan. Such a Participant's vested interest in his or her benefit under the Plan shall have a value of zero and such Participant shall be deemed to receive immediately upon the Participant's Termination of Employment a lump sum distribution of such vested interest and concurrent therewith the Participant shall forfeit his or her accrued benefit under the Plan.

Section 5.8. Special Rules Applicable to the Computation of Service Annuities . (a) Minimum Normal, Early Retirement and Deferred Vested Termination Benefits. The Service Annuity to which a Participant is entitled under Section 5.2 (relating to normal or deferred retirement) or Section 5.3 (relating to early retirement) shall in no event be less than the hypothetical Service Annuity which the Participant would have been entitled to receive had the Participant retired under Section 5.3 (relating to early retirement) at any time prior to the Participant's actual date of retirement and elected to have such hypothetical Service Annuity commence on the Participant's hypothetical early retirement date; provided, however, that any difference between such Service Annuities which is attributable to an increase in the amount of the Participant's Federal Benefit due to changes in the Federal Social Security Act between such hypothetical early retirement date and the Participant's date of retirement shall be disregarded.

(b) Termination of Employment During Authorized Absence . In computing the annual amount of the Service Annuity pursuant to Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to deferred vested termination) for a Participant whose Termination of Employment occurs during an authorized absence from employment which is included in the Participant's years of Credited Service pursuant to subdivision (12) of Section 2.1 (relating to the definition of Credited Service), such Participant shall be considered to have terminated employment on the earliest of (i) the date the authorized absence ends, (ii) the date that is twelve months after the day the authorized absence began and (iii) the date of the Participant's Termination of Service.

(c) Service Annuities Based on Compensation In Excess of the Section 401(a)(17) Limits . In the case of a Participant whose Service Annuity was computed under this Article 5 as of the last day of any Plan Year (the "grandfather date") prior to the January 1, 1989 effective date of Section 401(a)(17) of the Code, which sets forth a compensation limit, or prior to the January 1, 1996 effective date of the reduction in the compensation limit set forth in Section 401(a)(17) of the Code (the applicable limit being referred to as the "new compensation limit"), based on Earnings or the aggregate amount of Base Pay and Incentive Pay in excess of the new compensation limit, such Participant's Service Annuity under this Article 5 (relating to Service Annuities) for periods after the applicable grandfather date shall be the greater of:

(i) the sum of (a) the Participant's Service Annuity determined as of such grandfather date, plus (b) the Participant's Service Annuity determined after such date by applying the new compensation limit and based only on the Participant's years of Credited Service after such date; and

(ii) the Service Annuity determined after the grandfather date by applying the new compensation limit and based on all of the Participant's years of Credited Service.

(d) Participants Formerly Employed at the Company's Fossil-Fired Generation Facilities .

(i) Participants entitled to a Service Annuity Under Section 5.7 . Notwithstanding anything contained in the Plan to the contrary, a "Terminated Participant" (as defined below) who, but for this subparagraph (i) of Section 5.8(d), would have his or her Service Annuity computed under Section 5.7 (relating to Deferred Vested Termination), shall have his or her Service Annuity computed under (a) Section 5.2 (relating to normal and deferred retirement) if the Participant is at least age 65 on the date his or her Service Annuity payments commence or (b) Section 5.3 (relating to early retirement) if the Participant is at least age 50, but not yet age 65, on the date his or her Service Annuity payments commence, in either case, treating the Participant (solely for purposes of Section 5.2 or 5.3, as the case may be, but not for any other purpose) as though his or her Termination of Employment occurred on the day immediately preceding the date that such Participant's Service Annuity payments commence; provided, however, that such Participant's Service Annuity shall be computed taking into account his Highest Average Annual Pay and Credited Service determined as of the date of his actual Termination of Employment. For purposes of the preceding sentence, a "Terminated Participant" shall mean a Participant whose Termination of Employment with the Company occurs as a result of the sale of any of the assets sold as part of a divestiture process commencing in 1998 of the Company's fossil-fired generation facilities to one or more purchasers, provided that, on the "Determination Date" (defined in subparagraph (iii) below), (a) the sum of such Participant's years of age and years of Credited Service, including as Credited Service any period between the Participant's actual Termination of Employment date and the "Determination Date" (defined in subparagraph (iii) below) equals or exceeds 60 and (b) such Participant is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement) or Section 5.3 (relating to early retirement).

(ii) "Determination Date" Used to Determine Eligibility for a Service Annuity Under Section 5.3 . Further notwithstanding anything contained herein to the contrary, for purposes of determining whether an "Eligible Participant" (as defined below) is entitled to a Service Annuity under Section 5.3 (relating to early retirement), such Eligible Participant shall be treated (solely for purposes of Section 5.3) as though his or her Termination of Employment occurred on the "Determination Date" (defined in subparagraph (iii) below). For purposes of the preceding sentence, an "Eligible Participant" shall mean a Participant whose Termination of Employment occurs as a result of the sale of any of the assets sold as part of a divestiture process commencing in 1998 of the Company's fossil-fired generation facilities to one or more purchasers, provided that, on the "Determination Date" (defined in subparagraph (iii) below), such Participant (a) has attained at least age 50 and (b) has at least ten years of Credited Service, including as Credited Service any period between the Participant's actual Termination of Employment date and the "Determination Date" (defined in subparagraph (iii) below).

(iii) Definition of Determination Date . For purposes of this Section 5.8(d), the "Determination Date" shall mean the later of the date on which the transfer of ownership of all FGG assets offered as part of a sale process commencing in 1998 has been completed or the date any remaining FGG assets have been removed by the Company from such sale process.

(iv) As required under Section 5.5(b)(i) of that certain Asset Sale Agreement By and Between Commonwealth Edison Company and Edison Mission Energy as to Fossil Fuel Generating Assets dated as of March 22, 1999, (A) the benefits payable under the Plan to any Participant who becomes employed by Edison Mission Energy or any subsidiary thereof on the date the transactions contemplated by that Agreement are consummated (a "Transferred Participant") shall be fully vested and nonforfeitable, effective as of the Determination Date (as defined in subparagraph (iii), above), and (B) no Transferred Participant shall accrue additional benefits under the Plan after the Determination Date, or, if later, the date of such Transferred Participant's Termination of Employment.

(e) Rehired Participants. Notwithstanding anything contained herein to the contrary, if a Participant terminates employment and is reemployed as an Employee under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees, including that the Participant waives participation in, or additional benefits and accruals under the Plan, such Participant's Service Annuity shall be computed by excluding all service completed, and compensation earned, during such period of reemployment.

(f) Participant's Death During Qualified Military Service. Effective January 1, 2007, in the case of a Participant who dies while performing Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any (other than benefit accruals relating to the period of Military Service), provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

Section 5.9. Post Retirement Adjustments. The annual Service Annuity payable pursuant to this Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms) that commences by reason of (a) the Termination of Employment of a Participant after the Effective Date under circumstances that entitle the Participant to a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45), Section 5.5 (relating to disability retirement before age 45) or Section 5.7 (relating to deferred vested terminations), or

(b) the Termination of Employment of the Participant after the Effective Date by reason of the Participant's death shall, subject to the limitations set forth in this Section 5.9, be adjusted each October 1 for the twelve-month period then beginning by adding a post-retirement cost of living adjustment computed by applying an adjustment percentage to the appropriate base specified in this Section 5.9.

(a) The adjustment percentage shall equal, for each October 1, the percentage by which the Consumer Price Index for the July immediately preceding such October 1 exceeds the Consumer Price Index for the July immediately preceding the twelve-month period beginning October 1 in which the Participant terminated employment under circumstances described in the first sentence of this Section 5.9 or payment of a Service Annuity commenced; provided, however, that:

(i) If, as of such October 1, there shall be no such excess, the adjustment percentage shall be deemed to be zero for the twelve-month period beginning on such October 1.

(ii) There shall be no negative adjustment percentage.

(iii) The aggregate adjustment percentage for any twelve-month period beginning October 1 shall never be lower than the aggregate adjustment percentage for the preceding such period.

(iv) If the percentage increase in the Consumer Price Index computed for the twelve-month period beginning on October 1 does not exceed the aggregate adjustment percentage for the preceding twelve-month period by at least three percentage points, the aggregate adjustment percentage for the preceding twelve-month period shall continue in effect during such twelve-month period beginning on October 1.

(v) The aggregate adjustment percentage for any twelve-month period beginning on October 1 shall not be more than seven percentage points greater than that for the preceding twelve-month period. If the aggregate adjustment percentage for any twelve-month period beginning on October 1 exceeds by more than seven percentage points the aggregate adjustment percentage for the preceding twelve-month period, the excess shall be carried over to succeeding twelve-month periods until such excess is reduced to zero.

(vi) The adjustment percentage for the twelve-month period beginning with the October 1 next following the date the Participant's Service Annuity commences shall be the adjustment percentage determined in accordance with the preceding provisions of this Section 5.9 multiplied by a fraction the numerator of which shall be the number of full calendar months between such date and such October 1 and the denominator of which shall be twelve.

(b) To determine the amount of the monthly cost of living adjustment made after the Effective Date with respect to any employee who, on the date of his or her Termination of Employment is a member of IBEW Local Union 15, in the case of a Service Annuity payable to a Participant pursuant to this Article 5 (relating to Service Annuities) or Article 6 (relating to Service Annuity forms), the adjustment percentage shall be applied to the first $500 per month (effective December 1, 2000 for each Participant who is a member of IBEW Local Union 15, $1,000 per month) of his or her Service Annuity, computed pursuant to this Article 5 (relating to Service Annuities), subject to a maximum monthly adjustment of $1,000 or, if the monthly amount of such Service Annuity is less than $1,000 per month, subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. To determine the amount of the adjustment made after the Effective Date in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2 or surviving spouse annuity payable pursuant to Section 6.3 to the surviving Spouse of a deceased Participant, a family annuity payable pursuant to Section 6.2 to a surviving Dependent Minor Child or Children of a deceased Participant or a surviving dependent's annuity payable pursuant to Section 6.4 to a surviving Dependent Disabled Child or Children of a deceased Participant, the adjustment percentage shall be applied to the first $250 per month of such annuity or benefit, subject to a maximum monthly adjustment of $350 ($500 in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2) or, if the monthly amount of such annuity or benefit is less than $350 ($500 in the case of marital annuity under paragraph (b) of Section 6.1 or under Section 6.2), subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. Cost of living adjustments with respect to Service Annuities not described in the first sentence of this Section 5.9(a) shall be determined under the terms of the Plan as in effect at the time the adjustment was made. Notwithstanding anything herein to the contrary, the cost of living adjustments provided under this Section 5.9(a) may be the subject of bargaining between Commonwealth Edison Company and IBEW Local Union 15 beginning no earlier than the date negotiations commence regarding the successor agreement to the first collective bargaining agreement between the parties that expires on or after January 1, 2006.

(c) To determine the amount of the monthly cost of living adjustment made after the Effective Date with respect to any employee who is not described in paragraph (b), above, to in the case of a Service Annuity payable to a Participant pursuant to this Article 5 (relating to Service Annuities) or Article 6 (relating to Service Annuity forms), the adjustment percentage shall be applied to the first $500 per month of his or her Service Annuity, computed pursuant to this Article 5 (relating to Service Annuities), subject to a maximum monthly adjustment of $500 or, if the monthly amount of such Service Annuity is less than $500 per month, subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. To determine the amount of the adjustment made after the Effective Date in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2 or surviving spouse annuity payable pursuant to Section 6.3 to the surviving Spouse of a deceased Participant, a family annuity payable pursuant to Section 6.2 to a surviving Dependent Minor Child or Children of a deceased Participant or a surviving dependent’s annuity payable pursuant to Section 6.4 to a surviving Dependent Disabled Child or Children of a deceased Participant, the adjustment percentage shall be applied to the first $250 per month of such annuity or benefit, subject to a maximum monthly adjustment of $175 ($250 in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2) or, if the monthly amount of such annuity or benefit is less than $175 ($250 in the case of marital annuity under paragraph (b) of Section 6.1 or under Section 6.2), subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. Cost of living adjustments with respect to Service Annuities not described in the first sentence of this Section 5.9(a) shall be determined under the terms of the Plan as in effect at the time the adjustment was made.

ARTICLE 6

SERVICE ANNUITY FORMS

Section 6.1. Basic Service Annuity Form. (a) Unmarried Participants. A Participant who on his or her Annuity Starting Date is not married shall receive a Service Annuity payable in semi-monthly payments for the Participant's lifetime unless the Participant is eligible for and elects an optional form of Service Annuity under Section 6.2 (relating to optional Service Annuity forms) at the time and in the manner prescribed by paragraph (b) of Section 6.6 (relating to election of optional form of Service Annuity).

(b) Married Participants. A Participant who is married on his or her Annuity Starting Date and does not elect an optional form of Service Annuity under Section 6.2 (relating to optional Service Annuity forms) at the time and in the manner prescribed in paragraph (b) of Section 6.6 (relating to election of optional form of Service Annuity) shall receive in lieu of a Service Annuity payable in semi-monthly payments for the Participant's lifetime an annual marital annuity payable in semi-monthly payments for the Participant's lifetime equal to the Participant's annual Service Annuity computed pursuant to Article 5 (relating to Service Annuities) reduced by the product of (1) 50% of the annual amount of Service Annuity the

Participant would have received under Article 5 (relating to Service Annuities) multiplied by (2) 40% of the applicable factor set forth in Table D. Thereafter, if the Participant's Spouse shall survive the Participant, such Spouse shall receive during the remainder of the Spouse's lifetime an annual Service Annuity payable in semi-monthly payments equal to 50% of the annual amount of Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime.

Section 6.2. Optional Service Annuity Forms. Upon written request to the Administrator made at the time and in the manner prescribed in paragraph (b) of Section 6.6 (relating to election of optional form of Service Annuity), a Participant may elect to receive, in lieu of the basic Service Annuity form described in Section 6.1, a Service Annuity in one of the following optional forms, provided that the Participant is eligible therefor:

Service Annuity Payable for the Life of the Participant: A Participant who is married on the Participant's Annuity Starting Date may elect, with spousal consent, to receive, in lieu of the marital annuity described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), a Service Annuity payable in semi-monthly payments for the Participant's lifetime.

Optional Marital Annuity: A Participant who is married on the Participant's Annuity Starting Date may elect to receive a marital annuity described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) with a Service Annuity payable to the Participant's Spouse, if the Participant predeceases such Spouse, of a percentage less than 50 of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime. A marital annuity described in this Section 6.2 shall be payable at the same time and in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) and shall be computed in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), except that the lesser percentage of Service Annuity designated by the Participant shall be used.

75% Marital Annuity: A Participant who is married on the Participant's Annuity Starting Date may elect to receive a 75% marital annuity with a Service Annuity payable to the Participant's Spouse, if the Participant predeceases such Spouse, of a percentage equal to 75 of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime. A 75% marital annuity described in this Section 6.2 shall be payable at the same time and in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) and shall be the actuarial equivalent of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities), determined by using the annual interest rate specified under section 417(e) of the Code for the November preceding the calendar year in which such distribution is made or commences, and the mortality table prescribed for purposes of section 417(e)(3)(A)(ii)(I) of the Code.

Family Annuity: A Participant who is not married on the Participant's Annuity Starting Date and who, as of such date, has a Dependent Minor Child or Dependent Minor Children may elect to receive a family annuity payable in semi-monthly payments for the Participant's lifetime and, thereafter, payable in semi-monthly payments in equal shares to each of the Participant's Dependent Minor Children who have not yet attained age 21. The annual amount of the family annuity payable to the Participant shall be the Participant's annual Service Annuity computed pursuant to Article 5 (relating to Service Annuities), reduced by the product of (1) the annual amount of the family annuity designated by the Participant for the Participant's surviving Dependent Minor Child or Children which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 (relating to Service Annuities) multiplied by (2) the applicable factor set forth in Table E. The annual amount of the family annuity payable after the Participant's death to the Participant's Dependent Minor Child or Children who have not yet attained age 21 shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 (relating to Service Annuities).

Surviving Dependent's Annuity: A Participant who is not married on the Participant's Annuity Starting Date and who, as of such date, has a Dependent Disabled Child or Dependent Disabled Children may elect to receive a surviving dependent's annuity payable in semi-monthly payments for the Participant's lifetime and, thereafter, payable in semi-monthly payments in equal shares to each of the Participant's Dependent Disabled Children who remain disabled. The annual amount of the surviving dependent's annuity payable to the Participant shall be the Participant's annual Service Annuity computed pursuant to Article 5 (relating to Service Annuities) reduced by the product of (1) the annual amount of the surviving dependent's annuity designated by the Participant for the Participant's Dependent Disabled Child or Children, which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 multiplied by (2) 50% of the applicable factor set forth in Table D, such factor to be determined based on the age of the other parent of such Child or Children, at the Participant's Annuity Starting Date or the age such other parent would have attained had such other parent survived or if, in either case, the age of such other parent cannot be determined, the age of the Participant. The annual amount of the surviving dependent's annuity payable after the Participant's death to the Participant's Dependent Disabled Child or Children who remain disabled shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 (relating to Service Annuities).

Section 6.3. <u>Pre-retirement Surviving Spouse Benefit</u>. (a) <u>Death Occurring During Employment after Completion of Ten Years of Credited Service</u>. Except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), if the Termination of Employment of a Participant who completed at least ten years of Credited Service shall occur by reason of the Participant's death, the Participant's Spouse, if the Participant is married on the date of the Participant's death, shall receive a surviving spouse annuity payable in semi-monthly payments for the surviving Spouse's lifetime commencing on the Service Annuity payment date immediately following the later of the Participant's death and the date the Participant would have attained age 65 or, in the event that the Participant dies prior to attainment of age 65, such earlier Service Annuity payment date elected by the surviving Spouse in writing in the manner specified by the Administrator. The annual amount of such surviving spouse annuity shall be 50% of the annual amount of the Service Annuity, computed pursuant to Section 5.2 (relating to normal and deferred retirement), that would have been payable to such Participant (i) had the Participant terminated employment the day before the Participant's death; or (ii) in the case of a Participant who dies before attaining age 55, had the Participant's Service Annuity commenced on the date the Participant would have attained age 55, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds that of the Participant's surviving Spouse. Notwithstanding the preceding sentence, in no event shall the annual amount of the surviving spouse annuity computed pursuant to this paragraph (a) of Section 6.3 be less than 50% of the annual amount of the marital annuity, computed pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), that would have been payable to such Participant (i) had payment of the Participant's marital annuity commenced the day before the Participant's death or (ii) in the case of a Participant who dies before attaining age 55, had payment of such marital annuity commenced at age 55 reduced by 1/2% for each month (but not to exceed 120 months) that the Participant's death precedes the date the Participant would have attained age 55 had the Participant survived, 1/6% for each month (but not to exceed 120 months) that the Participant's death precedes the date that the Participant would have attained age 45 had the Participant survived, and 1/12% for each month the Participant's death precedes the date that the Participant would have attained age 35 had the Participant survived.

(b) Death Occurring After Termination of Employment and Completion of Ten Years of Credited Service. If a Participant who completed at least ten Years of Credited Service and who is entitled to a deferred Service Annuity under Section 5.7 (relating to deferred vested termination) shall die before the Participant's Annuity Starting Date, the Participant's Spouse, if the Participant is married on the date of the Participant's death, shall be entitled to receive a surviving spouse annuity payable in semi-monthly payments for the surviving Spouse's lifetime commencing on or about the first Service Annuity payment date immediately following the later of the date of the Participant's death and the date the Participant would have attained age 65. Notwithstanding the preceding sentence, in the case of a Participant described in the preceding sentence who dies prior to attaining age 65, such Participant's surviving Spouse may elect, in writing in the manner specified by the Administrator, to receive payment of the surviving spouse annuity on any Service Annuity payment date following the later of the date of the Participant's death and the date the Participant would have attained age 50, but in no event later than the first Service Annuity payment date immediately following the date the Participant would have attained age 65. The annual amount of the surviving spouse annuity shall be 50% of the annual Service Annuity computed pursuant to Section 5.7 (relating to deferred vested termination), that would have been payable to such Participant (i) had payment of such deferred Service Annuity commenced the day before the Participant's death, or (ii) in the case of a Participant who dies before attaining age 50, had payment of the Participant's deferred Service Annuity commenced at age 50, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds the age of the Participant's surviving Spouse. Notwithstanding the preceding sentence, in no event shall the annual amount of the surviving spouse annuity computed pursuant to this paragraph (b) of Section 6.3 be less than 50% of the annual amount of the marital annuity, computed pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), that would have been payable to such Participant (i) had payment of the Participant's marital annuity commenced the day before the Participant's death or (ii) in the case of a Participant who dies before attaining age 50, had payment of such a marital annuity commenced at age 50.

(c) Death Occurring after Completion of at Least Five Years of Vesting Service but Less than Ten Years of Credited Service. Except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), if a Participant who has at least five years of Vesting Service but less than ten years of Credited Service shall die prior to the Participant's Annuity Starting Date, the Participant's Spouse, if the Participant is married on the date of the Participant's death, shall be entitled to receive a surviving spouse annuity payable in semi-monthly payments for the surviving Spouse's lifetime commencing on or about the first Service Annuity payment date immediately following the later of the date of the Participant's death and the date the Participant would have attained age 65. Notwithstanding the preceding sentence, the surviving Spouse of a Participant who is described in the preceding sentence and who dies before the Participant's 65th birthday may elect, in writing in the manner specified by the Administrator, to receive payment of the surviving spouse annuity on any Service Annuity payment date following the later of the date of the Participant's death and the date the Participant would have attained age 60, but in no event later than the first Service Annuity payment date immediately following the date the Participant would have attained age 65. The annual amount of the surviving spouse annuity shall be 50% of the annual Service Annuity computed pursuant to Section 5.7 (relating to deferred vested termination) that would have been payable to such Participant had payment of such deferred Service Annuity commenced at age 65, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds the age of the Participant's surviving Spouse. Notwithstanding the preceding sentence, in no event shall the annual amount of the surviving spouse annuity computed pursuant to this paragraph (c) of Section 6.3 be less than 50% of the annual amount of the marital annuity, computed pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) that would have been payable to such Participant had payment of such marital annuity commenced at age 65.

Except as provided in Section 6.4 (relating to pre-retirement surviving Child benefits) or Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), no Service Annuity or other benefit shall be payable under this Plan with respect to a Participant who dies prior to the Participant's Annuity Starting Date and who on the date of the Participant's death has no surviving Spouse. In addition, except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), no Service Annuity or other benefit shall be payable under this Plan with respect to a Participant who dies prior to completion of at least five years of Vesting Service.

Section 6.4. Pre-retirement Surviving Child Benefits. In the event of the death of any Participant who (i) has at least ten years of Credited Service and (ii) has on file with the Plan Administrator either a family annuity or a surviving dependent's annuity or, for Plan Years beginning on and after January 1, 2007, meets the eligibility conditions to elect a family annuity or surviving dependent's annuity, then, except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), such Participant's surviving Dependent Minor Children or Dependent Disabled Children, as the case may be, shall receive a surviving child annuity payable in semi-monthly payments commencing on the Service Annuity payment date immediately following the Participant's death and ending with the Service Annuity payment for the period next preceding the date on which (i) in the case of a family annuity, all of the Participant's Children have attained age 21 and (ii) in the case of a surviving dependent's annuity, all of the Participant's Children cease to be Dependent Disabled Children. The annual amount of such surviving child annuity shall be the annual annuity the Participant's Child or Children would have received (i) had the Participant terminated employment on the date of the Participant's death under circumstances entitling the Participant to a Service Annuity under Section 5.2 (relating to Normal and Deferred Retirement) or Section 5.3 (relating to Early

Retirement) and died subsequently, or (ii) in the case of a Participant who dies before attaining age 55, had the Participant terminated employment at age 55 under circumstances entitling the Participant to a Service Annuity under Section 5.3 (relating to Early Retirement) and died subsequently, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds the age of the other parent of such Child or Children at the Participant's death or the age such other parent would have attained on such date had such other parent survived or if, in either case, the age of such other parent cannot be determined, the age shall be deemed to be the same as the Participant.

Section 6.5. Death Benefits for Spouse or Child of Participant Who Dies During Employment After Age 65. Notwithstanding any provision of this Plan to the contrary, in the event of the death of any Participant who (a) has attained age 65 and (b) on the date of his or her death the Participant is married or has on file with the Plan Administrator an election for a family annuity or a surviving dependent's annuity or, for Plan Years beginning on and after January 1, 2007, meets the eligibility conditions to elect a family annuity or surviving dependent's annuity, the Participant's surviving Spouse, Dependent Minor Children or Dependent Disabled Children, as the case may be, shall receive the annuities they would have received had the Participant terminated employment on the date of the Participant's death under circumstances entitling the Participant to a Service Annuity under Section 5.2 (relating to Normal and Deferred Retirement) and died subsequently, or, in the case of a surviving Spouse, a surviving spouse annuity computed pursuant to the applicable paragraph of Section 6.3 (relating to pre-retirement surviving spouse benefits), if greater.

Section 6.6. Election Procedure. (a) Notice of Availability of Elections. No less than 30 days and no more than 90 days before the Participant's Annuity Starting Date, the Administrator shall give the Participant by mail or personal delivery written notice in nontechnical language that, if the Participant is eligible, the Participant may elect an optional form of Service Annuity set forth in Section 6.2 (relating to optional Service Annuity forms).

Notwithstanding the preceding sentence, the Administrator may deliver such notice to the Participant less than 30 days before the Participant's Annuity Starting Date, provided that (i) the Participant and the Participant's spouse (if any) waive any requirement that such notice be provided no less than 30 days before the Participant's Annuity Starting Date and (ii) payment of the Participant's Service Annuity commences more than 7 days after such notice is received by the Participant. The notice referred to herein shall mean a notice written in nontechnical language that includes a general description of the benefit forms provided under the Plan, including the terms and conditions of the basic benefit forms provided under the Plan and the circumstances under which such forms will be provided unless the Participant elects otherwise, with applicable spousal consent, a description of the eligibility conditions for and any material features of the optional forms of benefit, general information on the relative financial effect upon a Participant's benefit if he elects an optional form of benefit or revokes any prior election, and a description of the relative value of the optional forms of benefit as compared to a marital annuity. In no event shall payment of a Participant's monthly benefits commence before the notice is made available to the Participant and he has had an opportunity to make the election described in Section 6.1(b). Notwithstanding the foregoing, the notice described in the previous paragraph may be provided to the Participant subsequent to the Participant's Annuity Starting Date, if the Participant so elects, provided that the following conditions are satisfied:

(i) the date the on which the first payment to be received by the Participant is made (the "initial payment date") shall be no earlier than thirty (30) days following the date that the notice is furnished to the Participant, except that the initial payment date may be as early as the seventh day after such notice is provided if (i) such notice clearly indicates that the Participant has a right to a period of thirty (30) days after receiving the notice to consider to waive the basic forms of distribution provided under the Plan and to elect (with spousal consent) an optional form of benefit, (ii) the Participant affirmatively elects a form of distribution with the consent of his or her spouse (if required) to commence as of the initial payment date, and (iii) the Participant is permitted to revoke such election until the initial payment date;

(ii) the notice shall be provided to the Participant no more than ninety (90) days before the initial payment date, however, the Plan will not fail to satisfy the ninety (90)- day requirement if the delay in providing the distribution is due solely to an administrative delay;

(iii) the Participant is not permitted to elect an Annuity Starting Date that precedes the date upon which the Participant could have otherwise started receiving benefits under the terms of the Plan as in effect on the Annuity Starting Date;

(iv) to the extent that a Participant has not received any payments for the period from the Annuity Starting Date to the initial payment date, the Participant shall receive a one-time payment to reflect any such missed payments (a "make-up payment"). Such make-up payment shall be adjusted for interest from the period beginning on the Annuity Starting Date and ending on the initial payment date, which shall be calculated with respect to such payments that would have been received prior to the initial payment date. The interest rate used to compute the adjustment described in the preceding sentence shall equal the 30 Year Treasury rate for December of the preceding Plan Year. Notwithstanding the foregoing, with respect to any Annuity Starting Date on or after January 1, 2008, the interest rate used to compute the adjustment described in the sentence above shall be the interest rate as specified or prescribed by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code, in revenue rulings, notices or other guidance for November of the preceding Plan Year. For purposes of Section 7.1 of the Plan, the limitations set forth therein shall comply with the adjustments required thereto pursuant to Treasury Regulation 1.417(e)-1 with respect to any Annuity Starting Date described in this paragraph which is a "retroactive annuity starting date" as defined for purposes of such Regulation; and

(v) if a Participant who is married elects to commence the Participant's benefit as of the initial payment date pursuant to this paragraph, then the Participant's spouse (including an alternate payee who is treated as the Participant's spouse under a qualified domestic relations order), determined as of the initial payment date, must consent to such election if the survivor benefits payable as of the Annuity Starting Date are less than the survivor benefits payable under the benefit described in Section 6.2(b) of the Plan as of the initial payment date.

(b) Election of Optional Form of Service Annuity . Subject to the terms of, and except as otherwise provided by, this paragraph, a Participant may, at any time during the 90-day period ending on the Participant's Annuity Starting Date, elect, change or revoke (i) any form of

Service Annuity provided under this Plan and (ii) the percentage of the Participant's Service Annuity to be paid to a Spouse under a marital annuity, to a Dependent Minor Child under a family annuity or to a Dependent Disabled Child under a surviving dependent's annuity. Notwithstanding the preceding sentence, if the written notice described in paragraph (a) of this Section 6.6 is delivered to the Participant within 30 days of, or after, the Participant's Annuity Starting Date, the Participant may make an election, change or revocation as described in the preceding sentence at any time within 30 days after the date the written notice described in paragraph (a) of this Section 6.6 is delivered to the Participant. The Participant and the Participant's Spouse, if any, may waive the 30 day period described in the preceding sentence and begin receiving payment of the Participant's Service Annuity prior to the expiration of such 30-day period, provided that distribution of the Participant's Service Annuity commences more than 7 days after the notice described in paragraph (a) of this Section 6.6 is delivered to the Participant. An election, change or revocation described in this paragraph (b) shall be made by delivering a written notice describing the election, change or revocation to the Administrator. Notwithstanding the foregoing, if the Participant is married on the Participant's Annuity Starting Date, the Participant's election to receive an optional form of Service Annuity under Section 6.2 (relating to optional Service Annuity forms) in lieu of the marital annuity described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) shall not be effective unless (i) it shall have been consented to at the time of such election in writing by the Participant's Spouse and such consent acknowledges the effect of such election and is witnessed by either a Plan representative or a notary public, or (ii) it is established to the satisfaction of a Plan representative that such consent cannot be obtained because the Participant's Spouse cannot be located or because of such other circumstances as may be prescribed in Regulations. An election of an optional Service Annuity form shall be deemed a rejection of the basic Service Annuity form provided in Section 6.1 (relating to the basic Service Annuity form of payment). The consent of a Spouse required by this paragraph shall not be necessary for a distribution required by a qualified domestic relations order described in paragraph (b) of Section 13.2.

(c) Automatic Cancellation of Elections. If a Participant's Service Annuity is payable in the form of a marital annuity and if, prior to the Participant's Annuity Starting Date, the Participant's spouse dies or the Participant and such spouse divorce, the Participant's election or deemed election to receive a marital annuity shall, upon the Participant's notice to the Administrator of such death or divorce, be automatically cancelled, unless, subsequent to such spouse's death or the Participant's divorce and prior to the Participant's Annuity Starting Date, the Participant remarries and notice of such new marriage is timely received by the Administrator.

If a Participant's Service Annuity is payable in the form of a marital annuity and if, after the Participant's Annuity Starting Date, the Participant's Spouse predeceases the Participant or the Participant's Spouse, pursuant to a duly entered divorce decree, specifically relinquishes all rights to receive any Service Annuity in the event of the Participant's death, the Participant's Service Annuity shall be recomputed prospectively as if the Participant were not married on the Annuity Starting Date. Any marriage by the Participant after the Participant's Annuity Starting Date shall not affect the payment of the Participant's Service Annuity or require any payment to the Participant's new spouse.

If a Participant has elected to receive a family annuity and, either before or after payment of such annuity commences, all of the Participant's previously Dependent Minor Children have predeceased the Participant or have ceased to be dependent, within the meaning of Section 152 of the Code, the Participant's election to receive a family annuity shall, upon the Participant's notice to the Administrator of such death or cessation of being a dependent, be automatically cancelled.

If a Participant has elected to receive a surviving dependent's annuity and either before or after payment of such annuity commences, all of the Participant's previously Dependent Disabled Children have predeceased the Participant or have ceased to be Dependent Disabled Children, as certified by the medical director of the Company or by such other licensed physician designated by the Company, the Participant's election to receive a surviving dependent's annuity shall, upon the Participant's notice to the Administrator of such death or cessation of being a Dependent Disabled Child, be automatically cancelled.

A Participant whose election has been automatically cancelled pursuant to this paragraph (c) shall be entitled to receive the Service Annuity described in Section 6.1 (relating to the basic Service Annuity form of payment) or, in the case of an election that is automatically cancelled prior to the Participant's Annuity Starting Date and subject to Section 6.1 (relating to the basic Service Annuity form of payment), such other form of Service Annuity described in Section 6.2 (relating to optional Service Annuity forms) for which the Participant is eligible and elects in accordance with this Section 6.6.

Section 6.7. Lump Sum Payment. Notwithstanding anything herein to the contrary, if the monthly amount of any Service Annuity shall initially be or at any time become $10 or less, the Participant, Beneficiary or Retiree may, in lieu of such annuity, elect to receive, and within 30 days after such election there shall be paid to such Participant, Beneficiary or Retiree, an amount equal to the lump sum equivalent of such annuity calculated on the basis of the "applicable interest rate" as defined in Section 417 of the Code and the Regulations promulgated thereunder and the applicable mortality table. Notwithstanding the foregoing, for purposes of computing single sum payments on or after January 1, 2008, (i) the interest rate used shall be the interest rate as defined in Section 417(e)(3)(C) of the Code for the second month preceding the calendar year in which such distribution is made or commences and (ii) the mortality table shall be the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Annuity Starting Date occurs. Notwithstanding the foregoing, for purposes of computing single sum payments on or after December 1, 2012, other than under Section 6.9 (relating to Special Lump Sum Payment Option), (i) the interest rate used shall be the interest rate as defined in Section 417(e)(3)(C) of the Code for the fifth month (or, if more favorable to the recipient of a single sum payment between December 1, 2012 and December 1, 2013), the second month) preceding the calendar year in which such distribution is made or commences and (ii) the mortality table shall be the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Annuity Starting Date occurs.

In the case of a distribution pursuant to this Section 6.7 that is an “eligible rollover distribution” within the meaning of Section 402 of the Code and that is at least $200, an eligible distributee (as defined below) may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from the Service Annuity Fund to (i) an individual retirement account described in Section 408(a) of the Code, (ii) an individual retirement annuity described in Section 408(b) of the Code, (iii) an annuity plan described in Section 403(a) of the Code, (iv) an annuity contract described in Section 403(b) of the Code, (v) a retirement plan qualified under Section 401(a) of the Code, (vi) an eligible plan under Section 457(b) of the Code which is maintained by an eligible employer described in Section 457(e)(1)(A) of the Code (the terms of which permit the acceptance of rollover contributions) or (vii) effective January 1, 2008, a Roth IRA described in Section 408A of the Code; provided, however, that (x) with respect to a plan described in clause (vii), for transfers occurring before January 1, 2010, the Participant (or surviving Spouse of a Participant or a former Spouse who is an alternate payee under a qualified domestic relations order as defined in Section 414(p) of the Code) meets the requirements of Section 408A(c)(3)(B) of the Code and (y) with respect to a distribution (or portion of a distribution) to a person who is not the Participant or the surviving Spouse of the Participant, "eligible retirement plan" shall mean only a plan described in clause (i) or (ii) or effective January 1, 2010, clause (vii), that, in either case, is established for the purpose of receiving such distribution on behalf of such person. For purposes of the preceding sentence, the term "Spouse" shall include the Participant's surviving Spouse and the Participant's Spouse or former Spouse who is the alternate payee under a qualified domestic relations order. In addition, in the case of a distribution that occurs on or after January 1, 2008, a Beneficiary who is not the Spouse of the Participant may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from this Plan to (i) an individual retirement account described in section 408(a) of the Code or (ii) an individual retirement annuity described in section 408(b) of the Code that, in either case, is established for the purpose of receiving such distribution on behalf of the Beneficiary. Notwithstanding the foregoing, an eligible distributee shall not be entitled to elect to have less than the total amount of such distribution transferred as a rollover contribution unless the amount to be transferred equals at least $500. At least 30 days but no more than 90 days prior to the date on which the eligible distributee is entitled to receive a distribution described in this Section 6.7, a written explanation shall be provided to the eligible distributee of the availability of the direct rollover option, the rules that require income tax withholding on distributions, the rules under which the eligible distributee may roll over the distribution within 60 days of receipt and, if applicable, other special tax rules that may apply to the distribution.

For purposes of this Section 6.7, “eligible distributee” shall include the Participant, his Spouse or his alternate payee under a qualified domestic relations order within the meaning of Section 414(p) of the Code and, effective January 1, 2008, the Participant’s Beneficiary who is not the Participant’s Spouse.

Section 6.8. Distributions to Dependent Minor and Disabled Children. Any distribution under this Plan to a Dependent Minor Child or Dependent Disabled Child, or payment to any person for the account of a Dependent Minor Child or Dependent Disabled Child, as the case may be, shall discharge all obligations in respect of such payment, and none of the Company, the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, shall have any duty to see to the application by any third party of any distribution made to or for the benefit of such Dependent Minor Child or Dependent Disabled Child.

Section 6.9. Special Lump Sum Payment Option. (a) Eligibility. A Participant (but not his or her Beneficiary) may elect to receive, during the election period described in paragraph (b) of this Section 6.9, his or her deferred Service Annuity (“Deferred Service Annuity”) under Section 5.7 (relating to deferred vested termination) in the form of a lump sum payment (“Special Lump Sum Payment”) or, an “Immediately Commencing Annuity” (as defined below); provided, however, that:

(i) the Participant has a Termination of Employment on or prior to June 30, 2012 and does not die and is not rehired during the period beginning July 1, 2012 and ending on the date payment is made or commences in accordance with this Section 6.9;

(ii) such Termination of Employment is not on account of the Participant's disability, following which the Participant is receiving long-term disability payments under any long-term disability program of an Employer, including on June 30, 2012;

(iii) the Participant's Deferred Service Annuity is not subject to a qualified domestic relations order as defined in Section 414(p) of the Code;

(iv) the Participant is not immediately, as of his or her Termination of Employment, eligible for early retirement benefits in accordance with Section 5.3 (relating to early retirement);

(v) the Participant is not on a leave of absence or layoff from an Employer on June 30, 2012;

(vi) the Participant is not 70 ½ years of age or older as of October 1, 2012; and

(vii) the Participant can be located, after a diligent search, as necessary, by the Plan Administrator before July 1, 2012.

For each such Participant described in this paragraph (a) of Section 6.9, the term "Immediately Commencing Annuity" shall mean, as applicable, either:

(i) with respect to a Participant eligible to commence receipt of his or her Deferred Service Annuity as of December 1, 2012, in accordance with the requirements of Section 5.7 (relating to deferred vested termination), any applicable optional form of annuity described in Sections 6.1 (relating to basic service annuity forms) or 6.2 (relating to optional service annuity forms); or

(ii) with respect to any other Participant, a "Service Annuity Payable for the Life of the Participant," an "Optional Marital Annuity" or a "75% Martial Annuity," each as described in the first paragraph of Section 6.2 (relating to optional service annuity forms).

(b) Election and Election Period. To receive the distribution of benefits described in paragraph (a) of this Section 6.9, an eligible Participant must voluntarily elect to receive a distribution pursuant to this Section 6.9 by completing an election form and spousal waiver, if required, provided by the Administrator, and submitting such forms to the Administrator after October 1, 2012 and before the following dates, as applicable,

(i) November 15, 2012, with respect to a Participant whose Termination of Employment occurs on or after April 1, 1995 and who elects a Special Lump Sum Payment;

(ii) November 30, 2012, with respect to a Participants whose Termination of Employment occurs before April 1, 1995 and who elects a Special Lump Sum Payment; and

(iii) December 15, 2012, with respect to a Participant who elects an Immediately Commencing Annuity,

or such other period during 2012 determined by the Administrator.

The Administrator shall provide each eligible Participant, not less than 30 days and not more than 180 days before the Annuity Starting Date, an application form including a general description of the material features, as well as an explanation of the relative values and financial effect, of the optional forms of benefit available under this Section 6.9, in a manner that satisfies the notice requirements of Section 417(a)(3) of the Code and the Regulations thereunder. The form shall indicate the Participant's right to waive a survivor annuity, his surviving Spouse's right to consent to such waiver or refuse such consent, and the right to revoke any waiver, within the 180 day period preceding the Annuity Starting Date, and shall include a description of the right of the Participant, if any, to defer receipt of a distribution and the consequences of failure to defer such receipt, in accordance with Treasury guidance under Section 411(a)(11) of the Code.

(c) Amount of Payment. The Special Lump Sum Payment shall equal the actuarial equivalent of the Participant's nonforfeitable Deferred Service Annuity, based on the following factors:

(i) the applicable interest rate described in Section 417(e)(3) of the Code for August of 2011;

(ii) an assumed commencement date of the later of (A) age 62, with respect to a Participant whose Termination of Employment occurs on or after April 1, 1995, or 65, with respect to a Participant whose Termination of Employment occurs before April 1, 1995, and (B) the Participant's age as of December 1, 2012;

(iii) the applicable mortality table, as defined in Section 417 of the Code and the Regulations promulgated thereunder; and

(iv) an assumed cost of living adjustment of 2.5% for purposes of Section 5.9 (relating to post retirement adjustments).

The Immediately Commencing Annuity shall be calculated:

(i) in accordance with the applicable terms of the Plan, for a Participant who is eligible to immediately commence benefits under the terms of the Plan as of the payment date set forth in paragraph (d) of this Section 6.9; and

(ii) as the actuarial equivalent of the Special Lump Sum Payment, for each other Participant.

(d) Payment of Benefit. If an eligible Participant elects the distribution of his or her Deferred Service Annuity in accordance with this Section 6.9, payment shall be made, or commence to be made, on or before December 1, 2012, or as soon as administratively practicable thereafter.

(e) Death and Rehire. If an eligible Participant elects the distribution of his or her Deferred Service Annuity in accordance with this Section 6.9 and subsequently dies or is rehired as an Employee before distributions commence, his or her election shall be null and void and the Participant's benefit shall be paid pursuant to the Plan without regard to this Section 6.9. Notwithstanding anything contained herein to the contrary, upon distribution of a Special Lump Sum Payment or an Immediately Commencing Annuity made to an individual in accordance with this Section 6.9, in the event of the individual's rehire with an Employer following the date such distribution is made, the individual shall not be eligible to participate in the Plan during such period of rehire and may be eligible to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees (or such other plan that applies to employees of an Employer hired on or after December 1, 2012), as applicable, in accordance with their terms and conditions.

ARTICLE 7

LIMITATIONS ON BENEFITS

Section 7.1. Maximum Annual Benefits. Notwithstanding any other provision of the Plan to the contrary, the amount of the Participant's annual benefit (as defined below) accrued, distributed or payable at any time under the Plan shall be limited to an amount such that such annual benefit and the aggregate annual benefit of the Participant under all other defined benefit plans maintained by the Employer or any other Affiliate does not exceed the lesser of:

(i) $160,000 (as increased to reflect the cost of living adjustments provided under Section 415(d) of the Code), multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of participation (within the meaning of Section 1.415(b)-1(g)(1)(ii) of the Regulations) and the denominator of which is 10; or

(ii) an amount equal to 100% of the Participant's average compensation for the 3 consecutive calendar years in which his or her compensation was the highest (as determined in accordance with Section 1.415(b)-1(a)(5) of the Regulations) and which are included in his or her years of service (within the meaning of Section 1.415(b)-1(g)(2)(ii) of the Regulations) with the Employers multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of service with the Employers and the denominator of which is 10.

The dollar amount set forth in clause (i) of the preceding paragraph shall be actuarially reduced in accordance with Section 1.415(b)-1(d) of the Regulations if the Participant's Pension Starting Date occurs prior to the Participant's attainment of age 62. If the Participant's Pension Starting Date occurs after the Participant's attainment of age 65, such dollar amount shall be actuarially increased in accordance with Section 1.415(b)-1(e) of the Regulations.

A Participant's "annual benefit" shall mean the Participant's accrued benefit payable annually in the form of a straight life annuity, as determined in, and accordance with, Section 1.415(b)-1(b) of the Regulations. If the annual benefit is payable in a form other than a single life annuity, the annual benefit shall be adjusted to the actuarial equivalent of a single life annuity using the assumptions of the following sentences; provided, however, that no adjustment shall be required for survivor benefits payable to a surviving spouse under a qualified joint and survivor annuity (as described in Section 6.1(b)) to the extent such benefits would not be payable if the Participant's annual benefit were paid in another form.

Effective for Plan Years beginning January 1, 2004 and January 1, 2005, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greater of (i) the amount computed using the annual interest rate specified under section 417(e) of the Code for the November preceding the calendar year in which such distribution is made or commences, and the mortality table prescribed for purposes of section 417(e)(3)(A)(ii)(I) of the Code (the "Actuarial Equivalent") and (ii) the amount computed using an interest rate assumption of 5.5% and the applicable mortality table under Section 1.417(e)-1(d)(2) of the Regulations (the "Applicable Mortality Table"). Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greatest of (i) the amount computed using the Actuarial Equivalent under the Plan, (ii) the amount computed using an interest rate assumption of 5.5% and the Applicable Mortality Table and (iii) the amount computed using the applicable interest rate under Section 1.417(e)-1(d)(3) of the Regulations and the Applicable Mortality

Table, divided by 1.05. Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit not subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be determined in accordance with Section 1.415(b)-1(c) of the Regulations. An individual's "annual benefit" under any other defined benefit plan maintained by the Employer and Affiliate shall be as determined pursuant to the provisions of Section 415 of the Code and the Regulations issued thereunder the terms of such plan.

Notwithstanding the foregoing provisions of this Section, the limitation provided by this Section shall not apply to a Participant who has not at any time participated in a defined contribution plan maintained by any Employer and whose annual benefit under the Plan does not exceed $10,000 multiplied by a fraction (not exceeding 1 and not less than 1/10th) the numerator of which is the Participant's years of years of service (within the meaning of Section 1.415(b)-1(g)(2)(ii) of the Regulations) and the denominator of which is 10.

For purposes of this Section, the term "compensation" shall have the meaning set forth in Section 415(c)(3) of the Code and the applicable Regulations, the term "defined contribution plan" shall have the meaning set forth in Section 1.415(c)-1(a)(2) of the Regulations, the term "defined benefit plan" shall have the meaning set forth in Section 1.415(b)-1(a)(2) of the Regulations and the term "Employer" shall include the Employers and all corporations and entities required to be aggregated with any of the Employers pursuant to Section 414(b) and (c) of the Code as modified by Section 415(h) of the Code. Section 415 of the Code and the Regulations thereunder are hereby incorporated by reference.

Section 7.2. Temporary Restrictions on Benefits in Case of Termination or Curtailment. This Section 7.2 sets forth restrictions required by the Internal Revenue Service on the Service Annuity payable for a Plan Year to a highly compensated employee or highly compensated former employee, as described in Section 414(q) of the Code and Regulations who is among the twenty-five highest paid nonexcludable employees in the service of the Employers for the Plan Year. The restrictions set forth in this Section 7.2 shall not become applicable if:

(1) after payment to such highly compensated employee of any Service Annuity, the value of Plan assets equals or exceeds 110 percent of the value of current liabilities (as defined in Section 412(l)(7) of the Code),

(2) the value of the Service Annuity paid to such highly compensated employee is less than one percent of the value of current liabilities of the Plan, or

(3) the value of the Service Annuity payable to or on behalf of such highly compensated employee does not exceed the amount described in Section 411(a)(11)(A) of the Code.

If the Service Annuity payable to a Participant is subject to the restrictions set forth in this Section 7.2, the Service Annuity provided from the Plan shall not exceed the payments that would be made on behalf of such Participant under a single life annuity that is the actuarial equivalent of the sum of the Participant's Service Annuity and the Participant's other benefits under the Plan.

The foregoing conditions do not restrict the full payment of any death or survivor's benefits on behalf of a Participant who dies while the Plan is in full effect and its full current costs have been met.

Any amounts that become due but because of the limitations of this Section 7.2, if applicable, cannot be made available to or for the Participant (either currently or later) shall be applied to reduce subsequent contributions of the Employers; but if the Employers have ceased contributions to the Plan, such amounts shall be applied for the benefit of Participants not affected by this Section 7.2 in an equitable and nondiscriminatory manner.

This Section 7.2 is inserted solely for the purpose of complying with the requirements of the Internal Revenue Service and shall not be applied except to the extent necessary to comply with such requirements.

Section 7.3 Benefit Restrictions as a Result of Funding. (a) Notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's "Adjusted Funding Target Attainment Percentage" (the "AFTAP"), as defined in Section 436(j) of the Code, is at or below the following levels.

(i) If the Plan's AFTAP is 60% or greater but less than 80% for a Plan Year, the Plan shall not pay any prohibited payment (as defined in subsection 7.3(a)(iv) below) after the valuation date for the Plan Year to the extent the amount of the payment exceeds the lesser of (x) 50% of the amount of the payment which could be made without regard to the restrictions under this subsection 7.3 and (y) the present value (determined pursuant to guidance prescribed by the Pension Benefit Guaranty Corporation, using the interest and mortality assumptions under Section 417(e) of the Code) of the maximum guarantee with respect to the Participant under Section 4022 of ERISA. Notwithstanding the preceding sentence, only one such prohibited payment may be made with respect to any Participant during any period of consecutive Plan Years to which the limitations under either clause (x) or (y) of the preceding sentence apply. For purposes of this subsection 7.3(a)(i), a Participant, his Beneficiary and any alternate payee (as defined in Section 414(p)(8) of the Code) shall be deemed a single "Participant."

(ii) If the Plan's AFTAP is less than 60% for a Plan Year, the Plan shall not pay any prohibited payment after the valuation date for the Plan Year.

(iii) During any period in which the Company is a debtor in a case under Title 11, United States Code (or similar federal or state law), the Plan shall not make any prohibited payment. The preceding sentence shall not apply on or after the date on which the Plan's enrolled actuary certifies that the AFTAP is not less than 100%.

(iv) For purposes of this subsection 7.3(a), the term "prohibited payment" means (x) any payment, in excess of the monthly amount paid under a single life annuity (plus any supplements described in Section 6.2), to a Participant or Beneficiary whose annuity starting date (as defined in Section 417(f)(2) of the Code and any regulations promulgated thereunder) occurs during any period a limitation under subsection 7.3(a)(ii) or (iii) is in effect, (y) any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or (z) any other payment specified by the Secretary of the Treasury by regulations.

(b) In any Plan Year in which the Plan's AFTAP for such Plan Year is less than 60%, benefit accruals under the Plan shall cease as of the valuation date for the Plan Year. This restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company or the Employers of a contribution (in addition to any minimum required contribution under Section 430 of the Code) equal to the amount sufficient to result in an AFTAP of 60%.

(c) No amendment which has the effect of increasing Plan liabilities by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accruals or the rate at which benefits become nonforfeitable shall take effect during any Plan Year if the Plan's AFTAP for such Plan Year is less than 80% or would be less than 80% after taking into account such amendment; provided, however, that the preceding restriction shall not apply to an amendment which provides for an increase in benefits under a formula which is not based on a Participant's compensation if the rate of such increase is not in excess of the contemporaneous rate of increase in average wages of Participants covered by the amendment; and provided, further, that such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year (or if later, the effective date of the amendment), upon payment by the Company or the Employers of a contribution as described in Section 436(c)(2) of the Code.

(d) The Plan shall not provide an unpredictable contingent event benefit payable with respect to any event occurring during any Plan Year if the AFTAP for such Plan Year is less than 60% or would be less than 60% after taking into account such occurrence; provided, however, such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company or the Employers of a contribution as described in Section 436(b)(2) of the Code. For purposes of this subsection 7.3(d), the term “unpredictable contingent event benefit” means any benefit payable solely by reason of a plant shutdown (or similar event, as determined by the Secretary of the Treasury), or any event other than the attainment of any age, performance of any service, receipt or derivation of any compensation, or occurrence of death or disability.

(e) To avoid benefit restrictions, the Company may take any action permitted by Section 436 of the Code and the regulations promulgated thereunder.

(f) The provisions of this subsection 7.3 are intended to comply with Section 436 of the Code and any regulations promulgated thereunder, and shall be construed to comply therewith.

ARTICLE 8

SERVICE ANNUITY FUND

The Service Annuity Fund is the Service Annuity Fund created by the Company for the payment of Service Annuities. All contributions under this Plan shall be paid to the Trustee. The Trustee shall hold all monies and other property received by it and shall invest and reinvest the same, together with the income therefrom, on behalf of the Participants collectively in accordance with the directions of the Investment Office. The Investment Office shall be a “named fiduciary” under the Plan for purposes of ERISA and, as such, may, in its discretion, delegate to one or more investment managers, as defined in ERISA, the authority to hold, manage, acquire and dispose of all or any part of the Service Annuity Fund. Any investment manager appointed by the Investment Office pursuant to this Article 8 which is a bank or trust company supervised by a State or Federal agency is authorized and empowered to invest and reinvest all or any part of the Service Annuity Fund allocated to it for investment in any common, collective or commingled trust qualified under the provisions of Section 401(a) and exempt from tax under Section 501(a) of the Code which is maintained by such investment manager ("common trust"). During such period of time as all or any portion of the Service Annuity Fund shall be invested in a common trust, the trust document governing such common trust shall govern any investment therein and such trust document shall be a part hereof. Investment of the common trust in deposits of the trustee of the common trust is hereby expressly authorized.

In addition, the Investment Office is authorized and empowered to direct the Trustee as to the investment and reinvestment all or any part of the Service Annuity Fund in the Commonwealth Edison Pooled Fund (the "Pooled Fund"). During such period of time as all or any portion of the Service Annuity Fund is invested in the Pooled Fund, the trust document governing the Pooled Fund shall govern any investment therein and such trust document shall be a part hereof. On and after November 1, 2010, the Service Annuity Fund shall be invested in the Exelon Corporation Pension Master Retirement Trust (the "Master Trust"), which is an amendment and restatement of the Pooled Fund, and the Master Trust document shall govern any investment therein. The Investment Office may delegate to one or more investment managers, as defined in ERISA, the authority to hold, manage, acquire and dispose of all or any part of the Service Annuity Fund invested in the Pooled Fund or, on and after November 1, 2010, in the Master Trust.

The Trustee shall make distributions from the Service Annuity Fund at such time or times to such person or persons and in such amounts as the Administrator shall direct in accordance with this Plan.

ARTICLE 9

SPECIAL RULES RELATING TO PARTICIPATION OF AND DISTRIBUTION TO CERTAIN TERMINATED OR TRANSFERRED EMPLOYEES

Section 9.1. Employment After Commencement of Service Annuity . A retired Employee or former Employee, other than an Employee described in either of the following paragraphs, receiving, or eligible to begin receiving, a Service Annuity may be employed in any business, including that of an Employer or an Affiliate, without in any way affecting the payment to him or her of his or her Service Annuity, provided however, that if he or she is employed by an Employer or an Affiliate, such employment satisfies the applicable conditions for continuation of payment of retirement benefits as set forth in the Company's policy regarding the rehiring of retirees.

A retired bargaining unit Employee or former bargaining unit Employee, if such bargaining unit Employee was a member of Local Union 15 (or a predecessor union), International Brotherhood of Electrical Workers, receiving a Service Annuity may be employed in any business, other than that of the Company, without in any way affecting the payment to him or her of his or her Service Annuity. Such retired bargaining unit Employee, or former bargaining unit Employee, receiving a Service Annuity may be employed in the temporary service of an Employer or an Affiliate, but, except as otherwise provided in paragraph (b) of Section 5.2, during the term of such employment, he or she shall not receive any Service Annuity payments unless such employment is for less than 40 Hours of Service per calendar month. Upon the conclusion of such temporary service employment, Service Annuity payments shall again be made to him or her, as described in Section 9.4 (relating to suspension of Service Annuities).

Notwithstanding anything contained herein to the contrary, a retired Employee or former Employee who becomes re-employed by an Employer or an Affiliate after his or her Service Annuity payments have commenced shall not, under any circumstances, have the right to elect to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees or any plan sponsored by CEG. In addition, a retired Employee or former Employee who becomes re-employed by an Employer after payments have begun to be paid to him or her under the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees or any plan sponsored by CEG shall not, under any circumstances, have the right to elect to participate in this Plan.

Section 9.2. Social Security Increases. The Service Annuity of a Retiree or a Participant who has terminated employment under circumstances that entitle the Participant to a deferred Service Annuity under Section 5.7 (relating to deferred vested termination) shall not be recomputed to reflect any change in the benefit levels payable under Title II of the Federal Social Security Act or any change in the wage base under such Title II if such change takes place after the earlier of the date payment of such Service Annuity commences or the date of such termination, as the case may be.

Section 9.3. Leased Employees. A leased employee (within the meaning of section 414(n)(2) of the Code) shall not be eligible to participate in the Plan. If a person who performed services as a leased employee (as defined below) of any Employer or Affiliate becomes an Employee, or if an Employee becomes such a leased employee, then any period during which such services were so performed shall be taken into account solely for the purposes of determining whether and when such person is eligible to participate in this Plan under

Article 3 (relating to participation), measuring such person's years of Vesting Service and determining when such person has terminated his or her employment for purposes of Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms) to the same extent it would have been had such service been as an Employee. In addition, any contributions or benefits provided under another plan to such leased employee by his or her leasing organization shall be treated as provided under this Plan and shall be taken into account under Section 7.1 to the extent required under Section 1.415(a)-1(f)(3) of the Regulations. This Section 9.3 shall not apply to any period of service during which such a leased employee was covered by a plan described in Section 414(n)(5) of the Code and during which the total number of leased employees did not constitute more than 20% of the Employer's non-highly compensated work force within the meaning of Section 414(n)(1)(C)(ii) of the Code. For purposes of this Plan, a "leased employee" shall mean any person who is not an employee of an Employer and who pursuant to an agreement between an Employer or Affiliate has performed services for an Employer or an Affiliate on a substantially full-time basis for a period of at least one year, which services were performed under the primary direction or control of an Employer or an Affiliate.

Section 9.4. Suspension of Service Annuities. (a) Notwithstanding anything contained in the Plan to the contrary and except as provided in paragraph (b) of Section 5.2 (relating to special rule for Participants who attain age 70-1/2 while employed), a Participant who remains an Employee after the Participant's Normal Retirement Age without having any Termination of Employment that results in the Participant beginning to receive his or her Service Annuity shall not be entitled to receive any Service Annuity for any calendar month of employment by an Employer or an Affiliate during which the Participant completes at least 40 Hours of Service. If the Service Annuity payments of a Participant described in the preceding sentence or a Participant described in either of the second or third paragraph of Section 9.1 (relating to employment after commencement of Service Annuity System) are suspended, then such payments shall resume at the earlier of (i) such Participant's actual retirement, or (ii) such Participant's ceasing to work 40 Hours of Service or more per calendar month. A Participant's Service Annuity payments which have been suspended pursuant to this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System) shall be resumed not later than the third calendar month after the calendar month in which the Participant ceases to be employed as described in the preceding sentence. The initial payment upon resumption of the Service Annuity payments shall include any amounts withheld during the period between the cessation of the period during which his or her Service Annuity was suspended and the resumption of payments, but shall not be actuarially adjusted for such delay in resumption of his or Service Annuity nor shall any Service Annuity payment be made with respect to any month during which his or her Service Annuity was suspended pursuant to this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System).

(b) No Service Annuity shall be suspended under this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System) unless the Participant is notified by personal delivery or first class mail during the first calendar month or payroll period in which the Service Annuity is being suspended. Such notice will contain such information as may from time to time be required by Section 2530.203-3(b)(4) of the regulations of the Department of Labor or any amendment thereto.

(c) If a Participant erroneously receives Service Annuity payments for a month during which such payments should have been suspended pursuant to this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System), then the Administrator may deduct from future Service Annuity payments such erroneously received payments. However, no such deduction may exceed in any one month 25 percent of that month's payment to which the Participant or the Participant's Beneficiary, as the case may be, would have been entitled.

Section 9.5. Reemployment Before Commencement of Service Annuity . (a) Employees Represented by IBEW Local Union 15 . The following rules shall apply to an Eligible Employee who is a member of a collective bargaining unit represented by IBEW Local Union 15 who incurs a Termination of Employment and who is rehired by an Employer prior to commencing his or her Service Annuity or any benefits under the Exelon Corporation Pension Plan for Bargaining Unit Employees:

(i) Rehire Date Before Absence of 5 Years. If an Employee terminates employment and is later rehired by an Employer before having an absence from employment with the Employers and their Affiliates of five years and, on the date of such Employee's rehire, the Employee is a member of a collective bargaining unit represented by IBEW Local Union 15, then either: (1) if such Employee was a Participant on the date his or her employment terminated, such Employee shall become a Participant in the Plan as of his or her rehire date or (2) if such Employee was not a Participant on the date his or her employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant.

(ii) Rehire Date After Absence of at Least 5 Years. If an Eligible Employee terminates employment, regardless of whether such Eligible Employee was a Participant on the date that his or her employment terminated, and is later rehired by an Employer after having an absence from employment with the Employers and their Affiliates of at least five years and, on the date of such Employee's rehire, the Employee is a member of a collective bargaining unit represented by IBEW Local Union 15, such Eligible Employee shall (A) if he or she was a Participant with a vested Service Annuity as of his or her termination date, become a Participant as of his or her rehire date, (B) if he or she was not a Participant as of his or her termination date and was a participant entitled to a vested benefit under the Exelon Corporation Pension Plan for Bargaining Unit Employees as of his or her termination date, he or she shall not be an Eligible Employee and shall not become a Participant, or (C) if he or she was neither a

Participant with a vested Service Annuity nor a participant entitled to a vested benefit under the Exelon Corporation Pension Plan for Bargaining Unit Employees as of his or her termination date, then, (1) if he or she is rehired prior to January 1, 2009, be permitted to elect, in accordance with procedures established by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to participate in the Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees as of his or her rehire date, or (2) if he or she is rehired on or after January 1, 2009, he or she shall not be an Eligible Employee and shall not become a Participant.

(b) Management Employees. The following rules shall apply to an Eligible Employee who is not a member of a collective bargaining unit represented by IBEW Local Union 15 and who is rehired by an Employer after a Termination of Employment and prior to commencing his or her Service Annuity or any benefits under the Exelon Corporation Cash Balance Pension Plan, as applicable:

(i) Rehire Date Before Absence of 5 Years. If an Employee terminates employment and is later rehired by an Employer before having an absence from employment with the Employers and their Affiliates of five years and, on the date of his or her rehire, such Employee is not a member of a collective bargaining unit represented by IBEW Local Union 15, then either: (1) if such Employee was a Participant on the date his or her employment terminated, such Employee shall be Participant in the Plan as of his or her rehire date if he or she is then an Eligible Employee or (2) if such Employee was not a Participant on the date his or her employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant. Notwithstanding clause (1) of the preceding sentence, if an Eligible Employee described in the preceding sentence was not at any time permitted to make the election described in Section 3.2(a) or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his or her Service Annuity and related assets transferred to such plan in the manner described in Section 3.2(b).

(ii) Rehire Date After Absence of at Least 5 Years. If an Employee terminates employment with the Employers and their Affiliates and the Employee was not a Participant or was a Participant who did not have a vested Service Annuity as of the date his or her employment terminated, and such Employee is rehired by an Employer after having an absence from employment with the Employers and their Affiliates of at least five years and, on the date of his or her rehire, such Employee is not a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall not be an Eligible Employee and shall not become a Participant upon such rehire. If a Participant with a vested Service Annuity terminates employment with the Employers and their Affiliates and the Participant is rehired after having an absence from employment with the Employers and their Affiliates of at least five years, such Participant shall remain a Participant upon his or her rehire. Notwithstanding the preceding sentence if a Participant described in the preceding sentence was not at any time permitted to make the election described in Section 3.2(a) or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his or her Service Annuity and related assets transferred to such plan in the manner described in Section 3.2(b).

Section 9.6. Employees whose Representation by IBEW Local Union 15 Changes. Except as provided in the last paragraph of Section 9.1 (relating to employment after commencement of Service Annuity) if an Employee who, on the day he or she first performed an Hour of Service with an Employer, was not a member of a collective bargaining unit represented by IBEW Local Union 15 and was not an Eligible Employee later becomes an Eligible Employee as a result of becoming a member of a collective bargaining unit represented by IBEW Local Union 15 and being employed at a facility that, as of October 19, 2000, was owned by Commonwealth Edison Company, Unicom Corporation or any affiliate of Unicom Corporation, such Employee shall become a Participant as of the date he or she first becomes a member of a collective bargaining unit represented by IBEW Local Union 15, provided that such Employee becomes a member of a collective bargaining unit represented by IBEW Local Union 15 prior to January 1, 2009 and does not elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date for such an election, to participate in the Exelon Corporation Pension Plan for Bargaining Unit Employees. Except as provided in the last paragraph of Section 9.1 (relating to employment after commencement of Service Annuity) if an Employee who was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer prior to January 1, 2001 later ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall be permitted to elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to either (a) continue to participate in the Plan as of the date he or she ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15 or (b) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his or her Service Annuity and related assets transferred to such plan in the manner described in Section 3.2(b).

Section 9.7. Transfer of Employment to or Reemployment in Positions Eligible for Participation in the Plan or the Service Annuity Plan of PECO Energy Company by Certain Individuals Who Were Participants in Such a Plan on December 31, 2000. If a Participant who was a Participant on December 31, 2000 transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in the Service Annuity Plan of PECO Energy Company (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Service Annuity Plan of PECO Energy Company. If a participant in the Service Annuity Plan of PECO Energy Company who was a participant in such plan on December 31, 2000 transfers employment to or is reemployed by an Employer or an Affiliate in a management job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a participant in the Service Annuity Plan of PECO Energy Company and shall not participate in the Plan.

Section 9.8. Change in Employment Status or Transfer to Affiliate. Except as otherwise provided in Sections 9.9, 9.10 and elsewhere in the Plan, if an Employee who was a Participant transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead either eligible to participate in another plan maintained by such Employer or Affiliate or are not eligible to participate in any plan, then such individual shall upon such transfer or reemployment participate in the plan, if any, determined pursuant to rules established by the Company, which rules may be set forth in a Supplement hereto.

Section 9.9. Certain Rehired Employees. Notwithstanding anything contained herein to the contrary, an Employee who is reemployed by an Employer after December 1, 2012 and has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 6.9 (relating to Special Lump Sum Payment Option) shall not be eligible to become a Participant pursuant to Article 3.

Section 9.10. Transfer of Employment to or from Facilities formerly Owned by CEG. Effective as of the Effective time (as such term is defined in the Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code (each such plan, a "CEG Pension Plan") , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Pension Plan. If a participant in the CEG Pension Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Pension Plan and shall not participate in the Plan.

ARTICLE 10

ADMINISTRATION

Section 10.1. The Administrator, the Investment Office and the Corporate Investment Committee . (a) The Administrator. The Company, acting through its Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Retirees, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan. The determination of the Administrator with respect to an Employee's years of Credited Service, the amount of the Employee's Earnings, Highest Average Annual Pay, Federal Benefit and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his or her discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his or her duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 6 (relating to Service Annuity forms). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Retirees, the amounts of all Service Annuities, the dates of death of Retirees and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Service Annuities to be paid out of the Service Annuity Fund.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator. The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

(c) The Investment Office. The Investment Office shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Sections 404(a)(2) of ERISA and the terms of the Plan and all other applicable limitations. In addition to the duties, responsibilities and rights of the Investment Office set forth in Article 8, the Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Trust Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Office.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

(d) The Corporate Investment Committee. The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Office and shall review annual manager review results and any other reports and documents submitted by the Investment Office.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Office, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Office.

(iii) The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

(e) Status of Administrator, the Investment Office and the Corporate Investment Committee. The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

(f) Notice to Trustee of Members. The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

(g) Allocation of Responsibilities. Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

(h) General Governance. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

(i) Indemnification. The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

(j) No Compensation. None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

(k) Employ of Counsel and Agents. The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

Section 10.2. Claims Procedure. Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Section 13.8 and 13.9) to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to the officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

Section 10.3. Procedures for Domestic Relations Orders. If the Administrator shall receive any judgment, decree or order (including approval of a property settlement agreement) pursuant to State domestic relations or community property law relating to the provision of child support, alimony or marital property rights of a spouse, former spouse, child or other dependent of a Participant and purporting to provide for the payment of all or a portion of the Participant's Service Annuity to or on behalf of one or more of such persons (such judgment, decree or order being hereinafter called a "domestic relations order"), the Administrator shall promptly notify the Participant and each other payee specified in such domestic relations order of its receipt and of the following procedures. After receipt of a domestic relations order, the Administrator shall determine whether such order constitutes a "qualified domestic relations order" as defined in paragraph (b) of Section 13.2, and shall notify the Participant and each payee named in such order in writing of the Administrator's determination within a reasonable time after receipt of such order. Such notice shall be written in a manner calculated to be understood by the parties and shall contain an explanation of the review procedure under this Plan. If the Administrator determines that the order is not a "qualified domestic relations order," such notice also shall set forth specific reasons for the Administrator's determination. The Administrator shall advise each party that each party or a duly authorized representative of such party may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the Administrator's determination by filing with such officer within 60 days of receipt of the Administrator's determination a written request for such review. The Administrator shall give every party affected by any such request for review notice of such request. Each party also shall be informed that he or she may have reasonable access to pertinent documents and submit comments in writing to the officer in connection with such request for review. Within 60 days after a request for review, each party shall be given written notice of the officer's final determination, which notice shall be written in a manner calculated to be understood by the parties and shall include specific reasons for such final determination.

Section 10.4. Computation of Benefits. The benefit formula, factors contained in any Tables or Schedules and the Federal Benefit taken into account in determining the amount of a Participant's Service Annuity (including the amount paid under the applicable form of payment of such Service Annuity) or the amount of any surviving spouse or surviving child annuity payable with respect to any Participant shall be the formula, factors and/or Federal Benefit, as applicable, in effect on the date of the Participant's Termination of Employment.

Section 10.5. Actuary to Be Employed. The Company or the Investment Office shall engage an actuary to do such technical and advisory work as the Company or the Investment Office may request, including analyses of the experience of this Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Office of an annual actuarial report, which report shall contain information showing the financial condition of this Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Office.

Section 10.6. Funding Policy. The Company shall establish a funding policy and method consistent with the objectives of this Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Office.

Section 10.7. Notices to Participants, Etc. All notices, reports and statements given, made, delivered or transmitted to a Participant or any other person entitled to or claiming benefits under this Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or such other person at the address last appearing on the records of the Administrator.

Section 10.8. Notices to Employers or Administrator. Written directions, notices and other communications from Participants or any other person entitled to or claiming benefits under this Plan to the Employers or Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the forms prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

Section 10.9. Records. Each of the Administrator, the Investment Office and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

Section 10.10. Responsibility to Advise Administrator of Current Address. Each person entitled to receive a payment under this Plan shall file with the Administrator in writing such person's complete mailing address and each change therein. A check or communication mailed to any person at such person's address on file with the Administrator shall be deemed to have been received by such person for all purposes of this Plan. Although neither the Administrator nor the Trustee shall be obliged to search for or ascertain the location of any person, the Administrator shall make reasonable efforts to locate any missing Participant or Beneficiary entitled to benefits hereunder. If the Administrator is in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his or her last address known to the Administrator, notify such person that all future payments will be withheld until such person submits to the Administrator evidence of his or her continued life and proper mailing address.

Section 10.11. Electronic Media. Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

Section 10.12. Correction of Error. If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

ARTICLE 11

PARTICIPATION BY OTHER EMPLOYERS

Section 11.1. Adoption of Plan. With the consent of the Company, any entity may become a participating Employer under this Plan with respect to all or a designated group of its employees by taking such action as shall be necessary or desirable to adopt this Plan and executing and delivering such instruments as may be necessary or desirable to put this Plan into effect with respect to such entity.

Section 11.2. Withdrawal from Participation. Any Employer shall terminate its participation in the Plan at any time, under such circumstances as the Company may provide, by delivering to the Company a duly certified copy of a resolution of its board of directors (or other governing body) to that effect, or by ceasing to be a member of the same controlled group as the Company (within the meaning of section 1563(a) if the Code).

Section 11.3. Company and Administrator Agent for Employers . Each corporation which shall become a participating Employer pursuant to Section 11.1 (relating to adoption of the Plan) or Article 12 (relating to continuance by a successor) by so doing shall be deemed to have appointed the Company and the Administrator its agent to exercise on its behalf all of the powers and authorities hereby conferred upon the Company and the Administrator by the terms of this Plan, including, but not by way of limitation, the power to amend and terminate this Plan. The authority of the Company and the Administrator to act as such agent shall continue unless and until the portion of the Service Annuity Fund held for the benefit of Employees of the particular Employer and their Beneficiaries is set aside in a separate trust as provided in Section 15.2 (relating to establishment of separate plan).

ARTICLE 12

CONTINUANCE BY A SUCCESSOR

In the event that any Employer shall be reorganized by way of merger, consolidation, transfer of assets or otherwise, so that a corporation, partnership or person other than an Employer shall succeed to all or substantially all of such Employer's business, such successor may be substituted for such Employer under this Plan by adopting this Plan and, if necessary, becoming a party to the Service Annuity Fund. Contributions by such Employer shall be automatically suspended from the effective date of any such reorganization until the date upon which the substitution of such successor corporation for the Employer under this Plan becomes effective. If, within 90 days following the effective date of any such reorganization, such successor shall not have elected to become a party to this Plan, or if such successor shall adopt a plan of complete liquidation other than in connection with a reorganization, this Plan shall be automatically terminated with respect to employees of such Employer as of the close of business on the 90th day following the effective date of such reorganization or as of the close of business on the date of adoption of such plan of complete liquidation, as the case may be, and the Administrator shall direct the Trustee to distribute the portion of the Service Annuity Fund applicable to such Employer in the manner provided in Section 15.2 (relating to establishment of separate plan).

ARTICLE 13

MISCELLANEOUS

Section 13.1. Expenses. The expenses of the Trustee in the administration of the Service Annuity Fund, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Service Annuity Fund, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan, the Service Annuity Fund, the Pooled Fund or the Master Trust, as applicable, including, but not limited to, "direct expenses" incurred in administering the Plan, the Service Annuity Fund, the Pooled Fund and the Master Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan, the Service Annuity Fund, the Pooled Fund or the Master Trust), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Pooled Fund or the Master Trust, as applicable, shall be paid by the Trustee from the Service Annuity Fund or the Pooled Fund or the Master Trust, as applicable, in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Any such expenses that are borne by the Employers shall be paid out of their own funds in such proportions as the Administrator shall determine. In the event that the Company or any other Employer advances money on behalf of the Service Annuity Fund for the payment of any expenses incurred in the operation of the Plan, the Trustee shall reimburse the Company or such other Employer from the Service Annuity Fund for any amount so advanced, without interest or fees.

Section 13.2. Non-Assignability. (a) It is a condition of this Plan, and all rights of each Participant, Beneficiary and Retiree shall be subject thereto, that no right or interest of any Participant, Beneficiary or Retiree in this Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not by way of limitation, execution, levy, garnishment, attachment, pledge or bankruptcy, but excluding devolution by death or mental incompetency, and no right or interest of any Participant, Beneficiary or Retiree in this Plan shall be liable for, or subject to, any obligation or liability of such Participant, Beneficiary or Retiree, including claims for alimony or the support of any spouse or child, except as provided in paragraph (b) of this Section 13.2 (relating to exception for qualified domestic relations orders).

(b) Exception for Qualified Domestic Relations Orders . Notwithstanding any provision of this Plan to the contrary, if a Participant's Service Annuity under this Plan, or any portion thereof, shall be the subject of one or more qualified domestic relations orders, as defined below, such Service Annuity or portion thereof shall be paid to the person at the time and in the manner specified in any such order. For purposes of this paragraph (b), "qualified domestic relations order" shall mean any "domestic relations order" as defined in Section 10.3 (relating to procedures for domestic relations orders) which creates (or recognizes the existence of) or assigns to a person other than the Participant (an "alternate payee") rights to all or a portion of the Participant's Service Annuity under this Plan, and:

(A) clearly specifies

(i) the name and last known mailing address (if any) of the Participant and each alternate payee covered by such order,

(ii) the amount or percentage of the Participant's Service Annuity to be paid by this Plan to each such alternate payee, or the manner in which such amount or percentage is to be determined,

(iii) the number of payments to, or period of time for which, such order applies, and

(iv) each plan to which such order applies;

(B) does not require

(i) this Plan to provide any type or form of benefit or any option not otherwise provided under this Plan at the time such order is issued,

(ii) this Plan to provide increased benefits (determined on the basis of actuarial equivalence), or

(iii) the payment of benefits to an alternate payee which at the time such order is issued already are required to be paid to a different alternate payee under a prior qualified domestic relations order; and

(C) does not require the payment of benefits to any alternate payee before the first to occur of (i) the earliest date as of which payment of the Participant's Service Annuity could commence after his or her Termination of Employment, and (ii) the Participant's attainment of age 50,

all as determined by the Company pursuant to the procedures contained in Section 10.3 (relating to procedures for domestic relations orders). Any amounts subject to a domestic relations order prior to determination of its status as a qualified domestic relations order which but for such order would be paid to the Participant shall be segregated in a separate account or an escrow account pending such determination. If, within a reasonable time after receipt of written evidence of such order by the Company, it is determined that a domestic relations order constitutes a qualified domestic relations order, the amount so segregated (plus any interest thereon) shall be paid to the alternate payee in accordance with the terms of the order. If, within a reasonable time after receipt of a domestic relations order by the Company, it is determined that a domestic relations order does not constitute a qualified domestic relations order, then the amount so segregated (plus any interest thereon) shall, as soon as practicable, be paid to the Participant. Any subsequent determination that such order constitutes a qualified domestic relations order shall apply only to payments made on or after the date of such subsequent determination.

Section 13.3. Employment Non-Contractual. Neither this Plan nor any action taken by the Administrator or the Investment Office confers any right upon any Employee to continue in employment with any Employer.

Section 13.4. Limitation of Rights. No Participant, Beneficiary or Retiree shall have any right, title, interest or claim in or to any part of the Service Annuity Fund at any time, but shall have the right only to distributions from the Service Annuity Fund on the terms and conditions herein provided. Neither this Plan nor any action taken by the Administrator or the Investment Office shall obligate any Employer to make contributions to the Service Annuity Fund in excess of the contributions authorized by the board of directors of the Company or create any liability on an Employer for the payment of Service Annuities under this Plan.

Section 13.5. Merger or Consolidation with or Transfer to Another Plan. A merger or consolidation with, or transfer of assets or liabilities to, any other Plan shall not be effected unless the terms of such merger, consolidation or transfer are such that each Participant, Beneficiary, Retiree or other person entitled to receive benefits from this Plan would, if this Plan were to terminate immediately after the merger, consolidation or transfer, receive a benefit equal to or greater than the benefit such person would be entitled to receive if this Plan were to terminate immediately before the merger, consolidation, or transfer.

If an Employee or a group of Employees ceases to be an Employee or Employees of an Employer and becomes an employee or employees of an Affiliate that is not an Employer but that maintains its own pension plan, there shall be transferred from the Service Annuity Fund to the trust fund for the pension plan of such Affiliate assets in an amount equal to the proportion of the amount of the total assets of the Service Annuity Fund, after deducting therefrom the amount actuarially determined to be necessary for the payment in full of Service Annuities theretofore granted to all Retirees and Participants, which the actuarial reserve allocable to such Employee or such group of Employees, as the case may be, bears to the actuarial reserve allocable to all Employees. If, however, any such group of Employees shall include all of the Employees of all Employers, all of the assets of the Service Annuity Fund shall be so transferred.

If and when a separate pension plan and trust fund is created by the Company for supervisory, administrative and management Employees, there shall be transferred from the Service Annuity Fund to such separate trust fund assets in an amount equal to the sum of (a) that proportion of the amount of the total assets of the Service Annuity Fund, after deducting therefrom the amount actuarially determined to be necessary for the payment in full of Service Annuities theretofore granted to all Retirees and Participants, which the actuarial reserve allocable to such supervisory, administrative and management Employees bears to the actuarial reserve allocable to all Employees, and (b) the amount of assets actuarially determined to be necessary for the payment in full of Service Annuities theretofore granted to Retirees who were supervisory, administrative or management Employees at the time of the granting of such Service Annuities. If and when an Employee shall thereafter be transferred to or from the management payroll, there shall be transferred from the Service Annuity Fund to such separate trust fund or from such separate trust fund to the Service Annuity Fund, as the case may be, assets in an amount determined in the same manner as described in the preceding sentence (and the Employee’s Service Annuity or benefits in the nature of a service annuity shall subsequently be paid out of the Service Annuity Fund or such separate trust fund, as the case may be).

If and when an employee or a group of employees of an Affiliate that is not an Employer shall cease to be an employee or employees of such Affiliate and shall become an Employee or Employees of an Employer, the Trustee under the Service Annuity Fund shall accept, upon transfer from the trust fund of the pension plan of such Affiliate, assets in an amount equivalent to that proportion of the amount of the total assets of such trust fund, after deducting therefrom the amount actuarially determined to be necessary for the payment in full of benefits theretofore granted, which the actuarial reserve allocable to such Employee or such groups of Employees, as the case may be, bears to the actuarial reserve allocable to all employees. If, however, any such group of Employees shall include all of the employees of such Affiliate, all of the assets of such trust fund shall be so accepted.

In the case of each transfer of assets made or accepted pursuant to the provisions of this Section 13.5, the amount of the total assets and (if less than all assets are to be transferred) the proportion thereof to be transferred shall be determined as of a date not earlier than December 31 of the preceding calendar year.

All assets accepted, upon transfer, by the Trustee under the Service Annuity Fund, pursuant to the provisions of this Section 13.5, shall be held and applied in accordance with the provisions of the Trust Agreement relating to the Service Annuity Fund.

Section 13.6. Medical Examination. A Participant or Beneficiary for whom a determination or verification of physical or medical condition is in the opinion of the Administrator relevant to the application of this Plan shall, if and when reasonably requested by the Administrator, submit to medical examination by a physician appointed by the Administrator.

Section 13.7. Applicable Law. Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

Section 13.8. Statute of Limitations for Actions under the Plan. Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

Section 13.9. Forum for Legal Actions under the Plan. Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

Section 13.10. Legal Fees. Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Corporate Investment Committee, any Plan fiduciary, the Chief Human Resources Officer, any Plan administrator, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE 14

TOP-HEAVY PLAN REQUIREMENTS

Section 14.1. Top-Heavy Plan Determination. If, as of the determination date (as hereinafter defined) for any Plan Year, the aggregate present value of (a) the accrued Service Annuities under this Plan and the accrued benefits under all other defined benefit plans in the aggregation group (as defined below) and (b) the aggregate account balances under all defined contribution plans in such aggregation group, in each case with respect to all participants in such plans who are key employees (as defined in Section 416(i) of the Code) for such Plan Year, exceeds 60% of the aggregate of the present value of the Service Annuities, accrued benefits and account balances of all participants in such plans as of the determination date, then this Plan shall be a top-heavy plan for such Plan Year, and the requirements of Section 14.2 (relating to minimum benefit for top-heavy years), Section 14.3 (relating to top-heavy vesting requirements) and Section 14.4 (relating to special rules for applying statutory limitations on benefits) shall be applicable for such Plan Year as of the first day thereof. An employee's compensation, as defined in Section 1.415(c)-2 of the Regulations, from the Company and its Affiliates for a Plan Year shall be used, where applicable, in determining whether such employee is a key employee.

For purposes of the first sentence of the preceding paragraph, for any Plan Year, the Service Annuity accrued in respect of any Employee shall be the amount calculated as of the determination date, and the present value of such amount shall be based on the actuarial assumptions used in the actuarial valuation as of such determination date. The calculation of the present value of the Service Annuity accrued in respect of any Employee shall be subject to adjustments required under Section 416 of the Code.

If this Plan shall be a top-heavy plan for any Plan Year and not be a top-heavy plan for any subsequent Plan Year, the requirements of this Article shall not be applicable for such subsequent Plan Year except to the extent provided in Section 14.3 (relating to top-heavy vesting requirements).

For purposes of this Article, (a) the aggregation group shall consist of (i) if a key employee was a Participant in this Plan during the Plan Year containing the determination date (defined below) or any of the four preceding Plan Years, then this Plan and each other plan of an Employer which is qualified under Section 401(a) of the Code and in which a key employee is a participant during any of such Plan Years, (ii) this Plan and each other plan which enables this Plan to meet the requirements of Section 401(a)(4) or 410(b) of the Code during the Plan Year containing the determination date (defined below) or any of the four preceding Plan Years, and (iii) this Plan and each other plan of an Employer which it shall so designate and which together with this Plan shall satisfy the requirements of Sections 401(a)(4) and 410 of the Code; (b) the determination date for all plans in the aggregation group shall be the last day of the preceding plan year; and (c) the valuation date applicable to a determination date shall be (i) in the case of a defined benefit plan, the date as of which the most recent actuarial valuation for the plan year including the determination date is prepared, and (ii) in the case of a defined contribution plan, the date as of which account balances are determined which is coincident with or immediately precedes the determination date, except that if any such plan specifies a different determination or valuation date, such different date shall be used with respect to such plan. For the purpose of determining the Service Annuity, accrued benefit or account balance of a participant, any person who received a distribution from a plan in the aggregation group during the one-year period ending on the last day of the preceding plan year shall be treated as a participant in such plan, and any such distribution shall be included in such participant's Service Annuity, accrued benefit or account balance as the case may be, except that in the case of any distribution made for a reason other than severance from employment, death or disability, this sentence shall be applied by substituting "five-year period" for the "one-year period" stated herein.

Section 14.2. Minimum Benefit for Top-Heavy Years. (a) Subject to paragraph (b) of this Section 14.2 and the applicable reductions set forth in Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms), the annual amount of Service Annuity on a single life basis to which an eligible employee (other than an eligible employee who is a key employee as defined in Section 416(i) of the Code) is entitled at age 65 under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45), Section 5.5 (relating to disability retirement before age 45) or Section 5.7 (relating to deferred vested termination) shall in no event be less than (i) the product of (A) 2% of such eligible employee's average compensation, as described in Section 416(c) of the Code, from the Company and its Affiliates during such eligible employee's five highest-paid consecutive calendar years of service beginning after January 1, 1983 and while the Plan is top-heavy, multiplied by (B) the number of such eligible employee's years of Credited Service (but not in excess of ten) ending after

December 31, 1983 while the Plan is top-heavy less (ii) the annual actuarial equivalent of the eligible employee's vested portion of such eligible employee's account balances attributable to employer contributions and forfeitures, and earnings and losses thereon (including prior distributions thereof) and accrued benefits to which such eligible employee is entitled on Termination of Employment under all other qualified plans maintained by the Company or its Affiliates.

For purposes of this Article 14 (relating to top-heavy plan requirements), "eligible employee" shall mean any employee other than an employee who is included in a unit of employees covered by a collective bargaining agreement between employee representatives and an Employer, if there is evidence that retirement benefits have been the subject of good faith bargaining between such employee representatives and such Employer.

(b) The provisions of paragraph (a) shall not apply with respect to an eligible employee if, for each year in which this Plan is top-heavy, (i) the eligible employee's Employer also maintains a defined contribution plan which is included in the aggregation group for such year, and (ii) contributions made on behalf of each eligible employee other than key employees and forfeitures allocated to such eligible employee during such Plan Year are at least 5% of such eligible employee's compensation.

Section 14.3. Top-Heavy Vesting Requirements. Not-withstanding any provision of this Plan to the contrary, if an eligible employee's Termination of Employment occurs during a Plan Year in which this Plan is top-heavy and after the eligible employee has completed at least two years of Vesting Service but before the eligible employee has completed five years of Vesting Service, or after this Plan has been top-heavy and during the time this Plan was top-heavy such eligible employee has completed three years of Vesting Service, then such eligible employee shall be entitled, subject to Article 6 (relating to Service Annuity forms) and Article 7 (relating to limitation on benefits), to receive, determined in accordance with the following table, the vested percentage of the eligible employee's Service Annuity computed pursuant to Section 5.7 (relating to deferred vested termination):

Years of Vesting Service	Vested Percentage
2 but less than 3	20%
3 but less than 4	40%
4 but less than 5	60%
5 or more	100%

Section 14.4. Special Rules for Applying Statutory Limitations on Benefits . In any Plan Year for which this Plan is top-heavy, clauses (C)(I) and (D)(I) of the first paragraph of Section 7.1 (relating to maximum annual benefits) shall be applied by substituting "100%" for "125%" appearing therein unless, for such Plan Year (i) the percentage of Service Annuities accrued by Participants who are key employees does not exceed 90% of the Service Annuities accrued by all Participants, and (ii) the minimum accrued benefit of each Participant under all defined benefit plans in the aggregation group is at least 3% of such Participant's average compensation multiplied by each year of such Participant's Credited Service after 1983, not in excess of 10, while such plans are top-heavy.

ARTICLE 15

AMENDMENT AND TERMINATION

Section 15.1. Amendment. The board of directors of the Company (or a committee thereof) may at any time and from time to time amend or modify this Plan in any manner deemed by the board of directors of the Company to be necessary or desirable, provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility and, provided, further, that no amendment shall be made that affects Employees who are represented by IBEW Local Union 15 that is not consistent with that portion of the Company's collective bargaining agreements with IBEW Local Union 15 concerning the Plan. Any such amendment or modification shall become effective on such date as the board of directors of the Company shall determine and may apply to Participants in this Plan at the time thereof as well as to future Participants, provided, however, that no such amendment or modification which reduces the basis for the computation of Service Annuities shall be retroactive as to service prior to the date of such amendment or modification.

In addition, the Administrator may amend or modify subdivision (4) of Section 2.1 (relating to the definition of Basic Compensation) and subdivision (24) of Section 2.1 (relating to the definition of Incentive Pay) by changing such subdivisions as described therein.

Section 15.2. Establishment of Separate Plan. If an Employer shall withdraw from this Plan under Section 11.2 (relating to withdrawal from participation), the Investment Office shall determine the portion of the Service Annuity Fund held by the Trustee which is applicable to the Participants and Retirees of such Employer and direct the Trustee to segregate such portion in a separate trust. Such separate trust shall thereafter be held and administered as a part of the separate plan of such Employer.

Section 15.3. Termination of the Plan by an Employer. The Company may at any time, by resolution adopted by its board of directors, terminate this Plan in its entirety. In addition, any Employer may at any time terminate its participation in this Plan by resolution adopted by its board of directors to that effect. If the Internal Revenue Service shall refuse to issue an initial favorable determination letter that this Plan and the Service Annuity Fund as adopted by the Company meets the requirements of Section 401(a) of the Code and that the Service Annuity Fund is exempt from tax under Section 501(a) of the Code, any Employer may terminate its participation in this Plan and direct the Trustee to pay and deliver to that Employer the portion of the Service Annuity Fund applicable to its contributions.

Section 15.4. Distribution upon Termination or Partial Termination. Upon termination or partial termination of this Plan, the Service Annuities accrued as of the date of termination or partial termination, as the case may be, of all affected Participants shall be fully vested. After providing for any expenses of the termination of this Plan, or, in the event of the partial termination of this Plan, any expenses of such partial termination which are to be borne by the portion of the Service Annuity Fund applicable to those Employees affected by the partial termination, the remainder of such portion of the Service Annuity Fund (the "asset value") shall be allocated pursuant to the priority categories set forth in Section 4044 of ERISA and PBGC Regulations. In the event that after the termination of this Plan there is any asset value remaining after such allocation, the assets representing such asset value shall be paid over and applied for the benefit of the Employees of the Employers. The portion of the asset value allocated to provide Service Annuities to any person or group of persons may be applied for the benefit of such person or persons by the distribution of cash, continuance of the Service Annuity Fund, establishment of a new trust fund, purchase of annuities from an insurance company, or otherwise, as determined by the Company in its sole discretion. Notwithstanding the preceding sentences, if the Plan is terminated, the Service Annuity of each highly compensated employee as defined in Section 414(q) of the Code (and any former highly compensated employee) is limited to a Service Annuity that is nondiscriminatory under Section 401(a)(4) of the Code.

Section 15.5. Trust to Be Applied Exclusively for Participants and Their Beneficiaries . Subject only to the provisions of Section 4.2 (relating to return of contributions), Section 15.3 (relating to termination of the Plan by an Employer), Section 15.4 (relating to distribution upon termination or partial termination of the Plan) and any other provision of this Plan to the contrary notwithstanding, it shall be impossible for any part of the Service Annuity Fund to be used for or diverted to any purpose not for the exclusive benefit of Participants and their Beneficiaries either by operation or termination of this Plan, power of amendment or other means.

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its duly authorized officer on this ______ day of December, 2012.

EXELON CORPORATION

By ____
Chief Human Resources Officer

Exhibit 1

Items Included as Basic Compensation

Effective on and after April 1, 1995, the payments to Participants which shall be included in "Basic Compensation" for purposes of subdivision (4) of Section 2.1 of the Plan shall be as follows:

1. Regular earnings,
2. Nuclear license bonuses, and
3. Meter reader bonuses.
4. Payroll deductions for any commuter benefit offered to management employees pursuant to Section 132(f)(4) of the Code.

In addition, to the extent they relate to but are not a part of regular earnings for a given period which otherwise have been used in calculating Basic Compensation, the following items shall be included in the determination of "Basic Compensation" for purposes of subdivision (4) of Section 2.1 of the Plan:

1. Payments for disability absences,
2. Back pay included that is not subject to FICA and any other back pay which is awarded to the Participant and pursuant to which award the Participant is required to have such back pay included as Basic Compensation under the Plan,
3. Paid and unpaid absences,
4. Permissible rest period payments,
5. Credit for service by union officials on union business,
6. Payments allowed for military duty and
7. Credits allowed upon return from a military leave of absence.

Exhibit 2

Plans Included for Incentive Pay

Payments under the following plans shall be considered in determining a Participant's Incentive Pay, as defined in subdivision (24) of Section 2.1 of the Plan:

1. the Unicom Corporation 1995 Variable Compensation Award for Management Employees Under the Unicom Corporation Long-Term Incentive Plan,
2. any annual incentive award provided under the Unicom Corporation Long Term Incentive Plan or any other successor or other plan that provides annual incentive awards to Participants; provided, however that awards payable under any such plans with respect to any period beginning on or after January 1, 2001 to a Participant who is a member of IBEW Local Union 15 shall not be Incentive Pay for Plan purposes,
3. the Commonwealth Edison Pension Fund Management Incentive Pay Plan (effective January 1, 1993),
4. the Pension Fund Management Deferred Incentive Pay Plan (effective January 1, 1994),
5. the Commonwealth Edison Company Bulk Power Marketing Incentive Plan (effective April 1, 1994),
6. any variable pay plan negotiated by the Company with respect to its union Employees, and
7. Quarterly Incentive Awards paid to a management Employee pursuant to the Exelon Corporation Quarterly Incentive Award.

Supplement 1

Early Retirement Window for Certain Employees

This Supplement 1 sets forth the early retirement benefits available to each "Eligible Participant" (as defined below) who is at least age 50 and has completed at least 5 years of Credited Service (after taking into account the grant of any "Service Equivalent" under Section II below) and who submits a signed election and waiver and release of claims to the Company no earlier than the date of the Eligible Participant's "Termination Date" (as defined below), or, if later, 45 days after the Participant receives a summary of the benefits provided hereunder, on forms prescribed by the Company, electing one of the Options set forth below and waiving all employment-related claims against the Employers.

I. Definitions. As used in this Supplement 1, the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Cause. Willful commission of acts or omissions which have, have had, or are likely to have, a material adverse effect on the business, operations, financial condition or reputation of an Employer; or conviction (including a plea of guilty or *nolo contendere*) of a felony or any crime of fraud, theft, dishonesty or moral turpitude.

B. Eligible Participant. A Participant (i) whose employment with the Employers is terminated other than for Cause as a result of either (A) his or her Employer's restructuring related to the merger or pending merger of Unicom Corporation and PECO Energy or (B) the Participant's rejection of an offer of a Significant Transfer, (ii) who is notified that his or her Termination Date shall occur on or before December 31, 2002 and is eligible for the normal retirement benefits or early retirement benefits set forth in this Supplement 1, (iii) who continues employment with the Employers until the Termination Date set forth in the Participant's notification of eligibility (or until such earlier date permitted by the Employers) and who does not accept before such Termination Date (or, if later, the date the Eligible Employee's waiver of claims becomes effective) another position with any Employer, Exelon Corporation or any of their respective affiliates and (iv) who maintains an acceptable level of performance during the period ending on his or her Termination Date.

C. Service Equivalent. An amount equal to 12 months plus, if applicable, one additional week for each year of an Eligible Participant's Credited Service in excess of 10; provided, however, that only that portion of the Service Equivalent necessary to satisfy the eligibility requirements for an early retirement Service Annuity (granted under Section 5.3 or under the pension enhancement described in Section III B.2.b.) shall be taken into account for purposes of determining the amount of an Eligible Participant's early retirement Service Annuity.

D. Significant Transfer. An offer of a position with Exelon Corporation or a transfer (between or within business units) that, in either case, results in one or more of the following;

1. an increase in the Participant's one-way commuting distance of more than 50 miles;

2. a substantial change in the Participant's major position responsibilities and duties (as determined by the head of the Participant's business unit);

3. a salary band for the Participant that is lower than the salary band for the Participant's previous position; or

4. a reduction in the Participant's annual base salary or hourly compensation rate, as applicable.

E. Termination Date. The date on which an Eligible Participant's Termination of Employment occurs.

F. Week of Base Salary. In the case of an Eligible Participant who is a full-time Employee, a "Week of Base Salary" shall be determined by dividing (i) the Participant's annual base salary in effect on the his or her Termination Date, excluding any additives, premiums or other adjustments, by (ii) 52. In the case of an Eligible Participant who is a part-time Employee, a "Week of Base Salary" shall equal the product of (i) his or hourly compensation rate in effect on his or her Termination Date multiplied by (ii) the number of hours each week that such Participant is regularly scheduled to work with an Employer.

II. Grant of Service Equivalent. An Eligible Participant shall be granted a Service Equivalent only if, after addition of the Service Equivalent, the Participant would become eligible for an early retirement Service Annuity under Section 5.3 or would be deemed to be age 50 with at least 5 years of Credited Service. The Service Equivalent shall not be granted to a Participant if such Participant, as of his or her Termination Date, is eligible, without the addition of the Service Equivalent, for an early retirement Service Annuity under Section 5.3 or, as of his or her Termination Date, he or she has attained age 50 and has at least 5 years of Credited Service, unless in the latter case, the grant of the Service Equivalent would qualify the Eligible Participant for an early retirement Service Annuity under Section 5.3 pursuant to Section IIIb hereof.

III. Benefits.

A. Eligible Participants who are Age 50 with at Least 10 Years of Credited Service. Notwithstanding anything contained in the Plan to the contrary, if an Eligible Participant, after taking into account the Service Equivalent granted to such Eligible Participant under Section II hereof, is at least age 50 on his or her Termination Date and has at least 10 years of Credit Service as of such date or would be deemed to be age 50 with at least 10 years of Credited Service as of such date, such Eligible Participant shall be entitled to an early retirement Service Annuity under Section 5.3. Payment of the Eligible Participant's early retirement Service

Annuity under Section 5.3 shall commence at the time elected by the Eligible Participant, provided that the Eligible Participant has had a Termination of Employment and has attained at least age 50 (determined, for this purpose, by disregarding any Service Equivalent granted to the Eligible Participant). Payment shall be made in any form provided under the Plan.

B. Eligible Participants who are Age 50 with at Least 5, but Less than 10, Years of Credited Service. Notwithstanding anything contained in the Plan to the contrary, if an Eligible Participant, after taking into account the Service Equivalent granted to such Eligible Participant under Section II hereof, is at least age 50 on his or her Termination Date and has completed at least 5 but less than 10 years of Credited Service as of such date or would be deemed to be age 50 with at least 5 but less than 10 years of Credited Service as of such date, such Eligible Participant shall be entitled to elect one of the following normal or early retirement benefit under the Plan:

1. Option 1—Unreduced Additional Benefit. An additional benefit equal to 52 weeks of Base Salary. An Eligible Participant may elect to receive the additional benefit in the form of a lump sum distribution (which shall be paid in the same manner and subject to the terms provided under Section 6.7) or in any other form provide under the Plan. An Eligible Participant who elects this Option 1 shall not be eligible for an early retirement Service Annuity under Section 5.3.

2. Option 2 – Reduced Additional Benefit and Pension Enhancement. An Eligible Participant who elects Option 2 shall be entitled to the following two benefits:

   a. Reduced Additional Benefit. An additional benefit equal to 26 Weeks of Base Salary. An Eligible Participant may elect to receive the additional benefit in the form of a lump sum distribution (which shall be paid in the same manner and subject to the terms provided under Section 6.7) or in any other form provided under the Plan.

   b. Pension Enhancement. In lieu of a deferred Service Annuity under Section 5.7, a normal retirement Service Annuity under Section 5.2 or an early retirement Service Annuity under Section 5.3, using the Eligible Participant's age and years of Credited Service (including any Service Equivalent granted to the Eligible Participant under Section II hereof) as of his or her Termination Date (or, if later, the date that the Eligible Participant begins receiving his or her normal retirement Service Annuity under Section 5.2 or early retirement Service Annuity under Section 5.3). Payment of the Eligible Participant's normal retirement or early retirement Service Annuity shall commence at the time elected by the Eligible Participant, provided that the Eligible Participant has had a Termination of Employment and has attained at least age 50 or age 65, as applicable (determined, for this purpose, by disregarding an Service Equivalent granted to the Eligible Participant). Payment shall be made in any form provided under the Plan.

C. Eligible Participants who are not Age 50 or who do not have at Least 5 Years of Credited Service . An Eligible Participant who, (after the addition of any Service Equivalent) as of his or her Termination Date, is not age 50 or does not have at least 5 years of Credited Service shall not be entitled to any benefits under this Supplement 1.

D. Adjustments to Comply with Nondiscrimination Rules . If payment of the benefits described in this Supplement 1 to any Eligible Participant who is a “highly compensated employee,” as defined in section 414(q) of the Code would cause the Plan to fail any nondiscrimination requirements of section 401(a) of the Code, the benefits otherwise payable under this Supplement 1 shall be restricted in any manner determined by the Administrator so as to permit the Plan to satisfy such nondiscrimination requirements.

Exhibit A

Table B
Early Retirement Service Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied (a) to determine the reductions applicable to the early retirement Service Annuity of any Participant who is not a member of IBEW Local Union 15, and whose Termination of Employment occurs on or after April 1, 1995, and (b) to determine the reductions applicable to the early retirement Service Annuity of any Participant who is a member of IBEW Local Union 15 and whose Termination of Employment occurred after April 1, 1995 and before October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7200	.7225	.7250	.7275	.7300	.7325	.7350	.7375	.7400	.7425	.7450	.7475
51	.7500	.7525	.7550	.7575	.7600	.7625	.7650	.7675	.7700	.7725	.7750	.7775
52	.7800	.7825	.7850	.7875	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075
53	.8100	.8125	.8150	.8175	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375
54	.8400	.8425	.8450	.8475	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675
55	.8700	.8725	.8750	.8775	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975
56	.9000	.9025	.9050	.9075	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275
57	.9300	.9325	.9350	.9375	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575
58	.9600	.9617	.9633	.9650	.9667	.9683	.9700	.9717	.9733	.9750	.9767	.9783
59	.9800	.9817	.9833	.9850	.9867	.9883	.9900	.9917	.9933	.9950	.9967	.9983
60	1.0000											

Exhibit B

Table B1
Early Retirement Service Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied to determine the reductions applicable to the early retirement Service Annuity of any Participant who is a member of IBEW Local Union 15 whose Termination of Employment occurs on or after October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075	.8100	.8125	.8150	.8175
51	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375	.8400	.8425	.8450	.8475
52	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675	.8700	.8725	.8750	.8775
53	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975	.9000	.9025	.9050	.9075
54	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275	.9300	.9325	.9350	.9375
55	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575	.9600	.9625	.9650	.9675
56	.9700	.9725	.9750	.9775	.9800	.9825	.9850	.9875	.9900	.9925	.9950	.9975
57	1.0000											

Table B2
Early Retirement Supplemental Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied (a) to determine supplemental monthly payments to age 65 for any Participant who is not a member of IBEW Local Union 15 and whose Termination of Employment occurs on or after April 1, 1995, and (b) to determine the supplemental monthly payments to age 65 for any participant who is a member of IBEW Local Union 15 whose Termination of Employment occurred after April 1, 1995 and before October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.4200	.4175	.4150	.4125	.4100	.4075	.4050	.4025	.4000	.3975	.3950	.3925
51	.3900	.3875	.3850	.3825	.3800	.3775	.3750	.3725	.3700	.3675	.3650	.3625
52	.3600	.3575	.3550	.3525	.3500	.3475	.3450	.3425	.3400	.3375	.3350	.3325
53	.3300	.3275	.3260	.3225	.3200	.3175	.3150	.3125	.3100	.3075	.3050	.3025
54	.3000	.2975	.2950	.2925	.2900	.2875	.2850	.2825	.2800	.2775	.2760	.2725
55	.2700	.2675	.2650	.2625	.2600	.2575	.2550	.2525	.2500	.2475	.2450	.2425
56	.2400	.2375	.2350	.2325	.2300	.2275	.2250	.2225	.2200	.2175	.2150	.2125
57	.2100	.2075	.2050	.2025	.2000	.1975	.1950	.1925	.1900	.1875	.1850	.1825
58	.1800	.1775	.1750	.1725	.1700	.1675	.1650	.1625	.1600	.1575	.1550	.1525
59	.1500	.1479	.1458	.1438	.1417	.1396	.1375	.1354	.1333	.1313	.1292	.1271
60	.1250	.1229	.1208	.1188	.1167	.1146	.1125	.1104	.1083	.1063	.1042	.1021
61	.1000	.0979	.0958	.0938	.0917	.0896	.0875	.0854	.0833	.0813	.0792	.0771
62	.0750	.0729	.0708	.0688	.0667	.0646	.0625	.0604	.0583	.0563	.0542	.0521
63	.0500	.0479	.0458	.0438	.0417	.0396	.0375	.0354	.0333	.0313	.0292	.0271
64	.0250	.0229	.0208	.0188	.0167	.0146	.0125	.0104	.0083	.0063	.0042	.0021

Exhibit D

Table B3
Early Retirement Supplemental Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied to determine the supplemental monthly payments to age 65 for any Participant who is a member of IBEW Local Union 15 whose Termination of Employment occurs on or after October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.4100	.4075	.4050	.4025	.4000	.3975	.3950	.3925	.3900	.3875	.3850	.3825
51	.3800	.3775	.3750	.3725	.3700	.3675	.3650	.3625	.3600	.3575	.3550	.3525
52	.3500	.3475	.3450	.3425	.3400	.3375	.3350	.3325	.3300	.3275	.3250	.3225
53	.3200	.3175	.3150	.3125	.3100	.3075	.3050	.3025	.3000	.2975	.2950	.2925
54	.2900	.2875	.2850	.2825	.2800	.2775	.2750	.2725	.2700	.2675	.2650	.2625
55	.2600	.2575	.2550	.2525	.2500	.2475	.2450	.2425	.2400	.2375	.2350	.2325
56	.2300	.2275	.2250	.2225	.2200	.2175	.2150	.2125	.2100	.2075	.2050	.2025
57	.2000	.1979	.1958	.1938	.1917	.1896	.1875	.1854	.1833	.1803	.1782	.1761
58	.1750	.1729	.1708	.1688	.1667	.1646	.1625	.1604	.1583	.1563	.1542	.1521
59	.1500	.1479	.1458	.1438	.1417	.1396	.1375	.1354	.1333	.1313	.1292	.1271
60	.1250	.1229	.1208	.1188	.1167	.1146	.1125	.1104	.1083	.1063	.1042	.1021
61	.1000	.0979	.0958	.0938	.0917	.0896	.0875	.0854	.0833	.0813	.0792	.0771
62	.0750	.0729	.0708	.0688	.0667	.0646	.0625	.0604	.0583	.0563	.0542	.0521
63	.0500	.0479	.0458	.0438	.0417	.0396	.0375	.0354	.0333	.0313	.0292	.0271
64	.0250	.0229	.0208	.0188	.0167	.0146	.0125	.0104	.0083	.0063	.0042	.0021

APPENDIX B

SERVICE ANNUITY PLAN

OF

PECO ENERGY COMPANY

Under the Exelon Corporation Retirement Program

Amended and Restated Effective January 1, 2013

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SERVICE ANNUITY PLAN

OF

PECO ENERGY COMPANY

As Amended and Restated Effective January 1, 2013

The name of the plan set forth herein shall be the “Service Annuity Plan of PECO Energy Company” (the “Plan”). This Plan is an amendment and restatement of the Service Annuity Plan of PECO Energy Company as in effect on December 31, 2012 and, except as otherwise provided, shall apply to Employees whose employment is terminated on or after January 1, 2013 and to the beneficiaries of such Employees. The rights and benefits of Employees whose employment terminates before January 1, 2013 and of the beneficiaries of such Employees shall be determined under the Service Annuity Plan of PECO Energy Company as in effect at the time of such Employees’ termination, including any provisions of this Plan effective at such time; provided, however, that certain provisions of Articles 4 and 9 (relating to limitations on benefits), certain provisions of Article 2 (relating to special participation and distribution rules relating to recommencement of employment and employment by related entities), Article 8 (relating to administration), Article 9 (relating to amendment and termination of the Plan) and Article 10 (relating to miscellaneous provisions) shall be effective for all such persons.

ARTICLE I Definitions.

Whenever used in this Plan:

1.1 “Accrued Benefit” means the amount of pension payable in the form of a Single Life Annuity commencing on a Participant’s Normal Retirement Date (or, immediately, if the Participant has passed his Normal Retirement Date) accrued by a Participant under Article III as of the date of reference. Accrued Benefits shall only be payable in accordance with Articles IV and V.

1.2 “Active Participant” means a Participant who is an Eligible Employee.

1.3 “Actuarial Equivalent” means a benefit of equal actuarial value under the assumptions set forth in Appendix A.

1.4 “Administrator” means the Company acting through its Vice President, Health & Benefits or such other person appointed pursuant to Section 8.1.

1.5 “Affiliate” means, as of any time of reference: (a) any corporation included with the Company in a controlled group of corporations within the meaning of Section 414(b) of the Code, (b) any trade or business (whether or not incorporated) which is under common control with the Company within the meaning of Section 414(c) of the Code, (c) any member of any affiliated service group of which the Company is a member within the meaning of Section 414(m) of the Code, and (d) any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code; provided, however, that for purposes of Section 4.6, when applying Sections 414(b) and (c) of the Code, the phrase “more than 50%” shall be substituted for the phrase “at least 80%” each place it appears in Section 1563(a)(1) of the Code.

1.6 “Age” means age on last birthday, except that an individual attains age 70-1/2 on the corresponding date in the sixth calendar month following the month in which his seventieth birthday occurs (or the last day of such sixth month if there is no such corresponding date therein). Notwithstanding the preceding sentence, solely for purposes of determining whether a Participant is eligible to elect the Contingent Annuity Option under Section 5.3, “Age” means the Participant’s age on his nearest birthday, rounding his actual age up or down as appropriate.

1.7 “Benefit Accrual Computation Period” means the portion of a calendar year that begins on the latest of (a) January 1, (b) the date on which an Employee becomes an Eligible Employee or (c) the date an Active Participant resumes work after receiving benefits under the Company’s Disabilitant Plan (or June 1, 1992, for an Active Participant who is receiving benefits under the Company’s Disabilitant Plan on June 1, 1992) and ends on the earliest of (1) December 31, (2) the date an Employee ceases to be an Eligible Employee, (3) the date an Active Participant commences receiving benefits under the Company’s Disabilitant Plan (except with respect to Participants described in the proviso to the penultimate sentence of Section 1.9(b)), (4) an Employee’s Normal Retirement Date (in the case of an Employee who does not complete an Hour of Service on or after January 1, 1988), or (5) the date of an Employee’s death.

1.8 “Benefit Commencement Date” means, for any Participant, the date as of which his first periodic benefit payment or single sum payment is due. “Benefit Commencement Date” also means, with respect to a surviving Spouse or other beneficiary, the date on which the survivor’s benefit under Section 5.3 or 5.4 commences to the surviving Spouse or other beneficiary.

1.9 “Benefit Year” means a credit awarded as follows, subject to Article VI:

(a) Each Employee as of December 31, 1975 shall be credited with a number of Benefit Years equal to his years of service under the Plan as of that date;

(b) Each Active Participant shall be credited with one Benefit Year for each 12 month Benefit Accrual Computation Period after December 31, 1975 during which he completes 1,000 or more Hours of Service and 1/12th of a Benefit Year for each month or part of a month of a Benefit Accrual Computation Period of less than 12 months during which his Hours of Service equal or exceed 83 1/3 times the number of full months in the period. Benefit Years are not credited with respect to any period during which an Active Participant is receiving benefits under the Company’s Disabilitant Plan; provided, however, that Benefit Years shall be credited to an Active Participant who is receiving benefits under the Company’s Disabilitant Plan on June 1, 1992, with respect to any period after May 31, 1992 for which such benefits are received. Effective January 1, 2002, Benefit Years are credited with respect to any period following an Active Participant’s Separation from Service or absence on account of a disability for illness or accident during which the Participant is eligible for and receiving benefits under any long-term disability benefit plan sponsored by the Company.

(c) A Power Team Employee shall not receive credit for any Benefit Year that accrues while he is a Power Team Employee. Notwithstanding the foregoing, for the purposes of Section 5.3 only, a Power Team Employee shall be deemed to receive credit for Benefit Years to the extent such Power Team Employee otherwise would have earned such credit but for the provisions of this Section 1.9(c).

(d) An EIS Senior Management Employee shall not receive credit for any Benefit Year, or portion of a Benefit Year, that accrues after October 31, 1999, or the date on which such Participant becomes an EIS Senior Management Employee, if later, and the Benefit Accrual Computation Period for such Participant that would otherwise include such date shall end on such date. Notwithstanding the foregoing, for the purposes of Section 5.3 only, an EIS Senior Management Employee shall be deemed to receive credit for Benefit Years to the extent such EIS Senior Management Employee otherwise would have earned such credit but for the provisions of this Section 1.9(d).

(e) Notwithstanding the foregoing, for purposes of calculating a Participant's Benefit Years, each period of Qualified Military Service served by a Participant is, upon reemployment by the Company or an Affiliate within the time during which the Participant's right to reemployment is protected by applicable law, deemed to constitute service with the Company for such purposes.

1.10 "CEG" means Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the CEG Merger Agreement.)

1.11 "CEG Merger Agreement" means that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

1.12 "Code" means the Internal Revenue Code of 1986, as amended, or any superseding provision of law.

1.13 "Company" means, (i) prior to the Merger Date, PECO Energy Company, a Pennsylvania corporation (known prior to January 1, 1994 as the "Philadelphia Electric Company"), and any Affiliate of PECO Energy Company which adopts this Plan, and (ii) on and after the Merger Date, Exelon Corporation, PECO Energy Company, and any Affiliate of Exelon Corporation set forth on Appendix I which adopts this Plan either with respect to all Employees or a particular group of Employees of such Affiliate. Appendix I shall be updated from time to time by the Company to reflect any such adoption, but the failure to so update such Appendix shall not affect the effectiveness of any such adoption. Such adoptions will be effective whether occurring before, on or after the Effective Date and whether or not reflected in Appendix I.

1.14 “Compensation” means:

(a) for service prior to January 1, 1939 – normal full-time wages or salary at the established payroll rates;

(b) for service subsequent to December 31, 1938 wages, salary, and any other remuneration actually paid or credited to the Employee in recompense for his services as an Employee, including such amounts contributed at the direction of the Employee to the PECO Energy Company Employee Savings Plan, the Exelon Corporation Employee Savings Plan, the PECO Energy Company Employees’ Section 125 Plan, the Exelon Corporation Benefits Contributions Options, the Exelon Corporation Flexible Benefits Program or, effective January 1, 2002, amounts contributed on a pre-tax basis to a qualified transportation fringe benefit plan under Code Section 132(f)(4);

(c) effective for plan years beginning on or after December 12, 1994, for purposes of subsection (b) above, a Participant’s Compensation shall include the Compensation that the Participant would have received during a period of Qualified Military Service (or, if the amount of such Compensation is not reasonably certain, the Participant’s average earnings from the Company or an Affiliate for the twelve-month period immediately preceding the Participant’s period of Qualified Military Service); provided, however, that the Participant returns to work within the period during which his right to reemployment is protected by law.

The remuneration of an Employee who is absent for the purposes described in one of Sections 1.22(a) through 1.22(e) shall be deemed to continue at his base rate in effect immediately prior to the start of his absence; provided, however, that no Compensation shall be imputed under this sentence for any period prior to June 1, 1992 during which the Employee is receiving benefits under the Company’s Disabilitant Plan. Effective January 1, 1990, Compensation shall not include any lump sum payment of an Employee’s vacation pay or sick pay, nor any severance payment made by the Company or an Affiliate or pursuant to any plan maintained by the Company or an Affiliate. Compensation shall include annual incentive award payments under the Exelon Corporation Annual Incentive Award Program and quarterly incentive payments under the Exelon Corporation Quarterly Incentive Award Program payable with respect to years beginning on or after January 1, 2002.

Notwithstanding the foregoing, (i) Compensation for a Power Team Employee shall not include any Compensation earned while such Employee is a Power Team Employee; (ii) for an individual who retires after December 31, 1993 and prior to January 1, 1996, “Compensation” shall include all accrued vacation, accrued sick pay and severance payments for purposes of Section 3.1(a)(2) and 4C.3(a)(1)(A)(II); and (iii) Compensation for an EIS Senior Management Employee shall not include any Compensation earned after October 31, 1999 or the date on which such Participant becomes an EIS Senior Management Employee, if later.

1.15 “Corporate Investment Committee” means the Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

1.16 “Covered Compensation” means, as of any date of reference, the average of the taxable wage base in effect under the Social Security Act, as amended, in each of the thirty-five (35) consecutive years ending with the year prior to such Plan Year; provided however, that (i) for any Participant who has attained Age 65, “Covered Compensation” will at all times thereafter be “Covered Compensation” for the Plan Year in which the Participant attained Age 65, (ii) for any Participant who retires after December 31, 1993 and on or before January 1, 1995, Covered Compensation will be determined as of the year-end 1993, and (iii) for any Participant who retires after December 31, 1994 and on or before January 1, 1996, Covered Compensation will be determined as of year-end 1994.

1.12A “EIS” means Exelon Infrastructure Services, Inc.

1.12B “EIS Senior Management Employee” means an Employee of PECO Energy Company who is assigned to perform services for EIS on a full-time basis in a position that is eligible to participate in the EIS Long Term Incentive Plan.

1.17 “Eligibility Computation Period” means, with respect to any Employee, the twelve-month period beginning on his Employment Date and all calendar years beginning after his Employment Date.

1.18 “Eligibility Year” means a credit awarded as follows, subject to Article VI:

(a) Each Employee as of December 31, 1975, shall be credited with a number of Eligibility Years equal to the greater of:

(1) one Eligibility Year for each full year of the Employee’s service as of that date under the Plan as then in effect; or

(2) one Eligibility Year for each Eligibility Computation Period beginning before January 1, 1976, in which the Employee completed at least 1,000 Hours of Service, disregarding any Eligibility Computation Period that would have been disregarded under Article VI if it had applied at the time in question.

(b) Each Employee shall be credited with one Eligibility Year for each Eligibility Computation Period beginning after December 31, 1975, in which he completes 1,000 or more Hours of Service.

1.19 “Eligible Employee” means an Employee employed by the Company or on leave during a period of Qualified Military Service and, for the time period beginning on the Merger Date, who (a) was an Eligible Employee prior to the Merger Date or (b) first becomes an Employee on or after the Merger Date and is employed initially at a facility owned immediately before the Merger Date by PECO Energy Company or an Affiliate that was an Affiliate of PECO Energy Company immediately before the Merger Date.

Notwithstanding the foregoing, an Eligible Employee shall not include (i) an Employee who is employed by a joint venture in which the Company is a joint venturer, (ii) an Employee whose wages are subject to collective bargaining except to the extent a collective bargaining agreement relating to him so provides, (iii) a probationary Employee, (iv) an Employee who is an Employee solely by reason of being a leased employee within the meaning of Section 414(n) or 414(o) of the Code, (v) an Employee who executes a written waiver of his right to participate in the Plan (vi) an individual who is an independent contractor or any other person who is not treated by the Company or an Affiliate as an Employee for the purposes of withholding federal employment taxes, regardless of any contrary governmental or judicial determination relating to such employment status or tax withholding, (vii) on or after the Effective Time, an individual who was employed immediately prior to the Effective Time (as such term is defined in the CEG Merger Agreement) at CEG or a facility owned immediately before the Effective Time by CEG or (viii) an individual who is newly employed on or after the Effective Time (as such term is defined in the CEG Merger Agreement) at a facility owned immediately before the Effective Time by CEG.

Notwithstanding the foregoing, an Eligible Employee shall not include any Power Team Employee while he is a Power Team Employee, or any Employee of the Exelon Generation Company, LLC Power Team division who is a participant in the Commonwealth Edison Company Service Annuity System.

Notwithstanding the foregoing, effective October 31, 1999, an Eligible Employee shall not include any EIS Senior Management Employee. EIS Senior Management Employees hired on or after October 1, 1999 shall not be eligible to participate in the Plan.

Notwithstanding anything herein to the contrary, subject to the provisions relating to rehired employees in Section 2.10, no Employee who was not a Participant before January 1, 2001 shall be eligible to participate in the Plan after December 31, 2000.

An Eligible Employee who transfers employment to the Exelon Generation Company, LLC Power Team division during 2003 shall remain an Eligible Employee until December 31, 2003. An individual who has a benefit under this Plan and who transfers employment from the Exelon Generation, LLC Power Team division to a participating employer in this Plan shall not be an Eligible Employee prior to January 1, 2004.

Notwithstanding anything contained herein to the contrary, an Eligible Employee shall not include an individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 5.11.

1.20 “Employee” means a person who is employed by the Company or an Affiliate or is absent under circumstances included in his Employment. An individual shall be deemed to be actively employed by the Company or an Affiliate if such individual is employed directly by the Company or an Affiliate or is a leased employee within the meaning of Section 414(n) or 414(o) of the Code with respect to whose services the Company or Affiliate is the recipient and to whom Section 414(n)(5) of the Code does not apply. An individual who receives a back pay award from the Company or an Affiliate shall be deemed to be an Employee for the period for which back pay is awarded. An Employee shall cease to be such on his retirement, resignation, discharge, or death. Notwithstanding the foregoing, the term “Employee” shall not include independent contractors or any other persons who are not treated by the Employer as employees for purposes of withholding federal employment taxes, regardless of any contrary governmental or judicial determination relating to such employment status or tax withholding.

1.21 “Employer” means the Company.

1.22 “Employment” means active employment by the Company or an Affiliate. In addition, any of the following types of absence shall be counted as Employment (on the same work schedule under which the Employee was employed by the Company or Affiliate immediately prior to the absence) if it immediately follows a period of active employment with the Company or an Affiliate:

(a) absence due to a period of Qualified Military Service, if the Employee resumes work with the Company or an Affiliate, following discharge, within the time specified by then applicable laws.

(b) absence resulting from disability on account of illness or accident during which the Employee is eligible for and receives disability benefits under a disability benefit plan sponsored by the Company or an Affiliate.

(c) absence which the Company or an Affiliate certifies was for good cause.

(d) leave of absence granted by the Company or an Affiliate.

(e) lay-off, if the Employee returns to work within such period as may be specified in the rules of the Company or Affiliate in effect at the time of reference.

(f) absence during which regular remuneration is paid.

1.23 “Employment Date” means the day on which an Employee completes his first Hour of Service.

1.24 “Fund” means the assets accumulated for purposes of the Plan.

1.25 “Highly Compensated Employee” means, effective January 1, 2006, an Employee who performs services for the Company or an Affiliate during the current Plan Year who was:

(a) an Employee who was, at any time during the current Plan Year or in the immediately preceding Plan Year, a 5% owner, as defined in Section 416(i)(1) of the Code; or

(b) an Employee who, during the immediately preceding Plan Year, both (1) received compensation (as defined in Section 415(c)(3) of the Code plus, for Plan Years beginning after December 31, 2000, amounts excluded from income under Section 132(f)(4) of the Code) from the Company or an Affiliate in excess of $80,000, as adjusted by the Secretary of the Treasury in accordance with Section 415(d) of the Code, and (2) was in the group of employees consisting of the top 20% of the employees of the Company and its Affiliates when ranked on the basis of compensation paid during the preceding Plan Year.

1.26 “Hour of Service” means, for each Employee, a credit used to measure his service for various purposes under the Plan. Hours of Service are credited as follows:

(a) Each hour which is not included in a period described in Paragraph (b), below, but for which the Employee is directly or indirectly paid or entitled to payment by the Company or an Affiliate, for the performance of duties or otherwise, including back pay, without regard to mitigation of damages, shall count as one Hour of Service. Notwithstanding the preceding sentence, no Hours of Service shall be credited under this Paragraph (a) to the extent such credit will cause the Employee to be credited with more than 501 Hours of Service (including Hours of Service credited under Paragraph (b)) with respect to any single continuous period during which the Employee performs no duties; provided, however, that this limit shall not apply in the case of an award of back pay to the extent the award so specifies.

(b) Each week of absence for Qualified Military Service from which the Employee returns to the Company or an Affiliate with legally protected reemployment rights shall count as a number of Hours of Service determined under subsection (e) if the Employee was employed in a position designated as full-time immediately before the period of Qualified Military Service or, if subsection (e) does not apply, a number of Hours of Service equal to the number of hours of work in the Employee’s customary week of work at the time the absence began.

(c) Hours of Service for the performance of duties shall be credited to the Employee for the computation period or periods in which the services are performed. Hours of Service for non-performance of duties shall be credited to the Employee for the computation period or computation periods in which the non-performance of duties occurs. Hours of Service for back pay shall be credited to the Employee for the computation period or computation periods to which the award or agreement pertains rather than the computation period or periods in which it was made.

(d) Solely for purposes of determining whether a One-Year Break in Service (as defined in Article VI) has occurred in an Eligibility Computation Period or a Vesting Computation Period, an Employee who is absent from work for Maternity/Paternity Leave shall receive credit for the Hours of Service which would otherwise have been credited to such Employee but for such absence, or in any case in which such Hours of Service cannot be determined, eight Hours of Service per day of such absence. An Employee shall be credited with Hours of Service under this Paragraph (d) in the computation period in which the absence begins if necessary to prevent a Break in Service in that period, or, in all other cases, in the following computation period.

(e) An Employee who is employed by the Company or an Affiliate shall be credited with forty-five (45) Hours of Service for each week during which he is otherwise entitled to be credited with at least one Hour of Service. Paragraphs (a)-(c) notwithstanding, Hours of Service shall be credited at least as liberally as required by Department of Labor Regulation §2530.200b-2(b) and (c).

(f) In the case of an Employee who is such solely by reason of service as a leased employee (within the meaning of Section 414(n) or 414(o) of the Code), Hours of Service shall be credited as if such Employee were employed and paid with respect to such service (or with respect to any related absences or entitlement) by the Company or the Affiliate that is the recipient thereof.

1.27 “Investment Office” means the Company acting through the Exelon Investment Office.

1.28 “Maternity/Paternity Leave” means, for any Employee, an absence:

(a) by reason of the Employee’s pregnancy;

(b) by reason of the birth of the child of the Employee;

(c) by reason of placement of the child with the Employee in connection with the adoption of such child by the Employee; or

(d) for purposes of caring for such child for a period immediately following such birth or placement.

1.22A “Merger Date” means the effective date of the merger of Unicom Corporation with and into Exelon Corporation.

1.29 “Normal Retirement Date” means, for each Employee, the first day of the calendar month coincident with or next following the date he attains Age 65, except that the Normal Retirement Date of an Employee who becomes an Active Participant in the Plan after attaining Age 60 shall be the first day of the calendar month coincident with or next following the fifth anniversary of the date on which the Employee became an Active Participant.

1.30 “Participant” means (a) an Eligible Employee who has become an Active Participant under Article II, and (b) a former Active Participant whose Accrued Benefit and Benefit Years have not been canceled under Section 6.2 or have been restored under Section 6.5. An individual shall cease to be a Participant upon the date the individual is no longer eligible to receive a benefit from this Plan (including, without limitation, upon his or her receipt of a Special Lump Sum Payment as defined in Section 5.11).

1.31 “Plan” means the Service Annuity Plan set forth herein, provided that, on and after January 1, 1994, the Plan shall be known as the “Service Annuity Plan of PECO Energy Company” and on and after January 1, 2003, the Plan shall be known as the “Service Annuity Plan of PECO Energy Company under the Exelon Corporation Retirement Program.”

1.32 “Plan Year” means a calendar year after 1975. The Plan Year shall be the limitation year for purposes of computing limitations on contributions, benefits and allocations.

1.26A “Power Team Employee” means an Employee who is employed by the Exelon Generation Company, LLC Power Team division or its successor, and (i) who was not eligible to participate in the Plan before January 1, 2001, or (ii) who was eligible to participate in the Plan before January 1, 2001 but is eligible to participate in the performance share award program for Power Team employees under the Exelon Corporation Long Term Incentive Plan or any predecessor or successor incentive compensation program applicable to employees of the Power Team division. An Employee who is described in clause (ii) of the preceding sentence will be a Power Team Employee only during the period in which he satisfies clause (ii).

1.33 “Qualified Joint and Survivor Annuity” means the form of pension benefit described in this Section. Under a Qualified Joint and Survivor Annuity payments begin on the date provided in Article IV and continue until the first day of the month following the month in which the Participant’s death occurs. On the first day of the second month following the month of the Participant’s death, payments in an amount equal to 50% of the amount payable to the Participant begin to his surviving Spouse, but only if the Spouse was married to the Participant on the Participant’s Benefit Commencement Date. Such payments to the Spouse shall end on the first day of the month following the month in which the Spouse’s death occurs. The anticipated payments under a Qualified Joint and Survivor Annuity shall be the Actuarial Equivalent of a pension in the form of a Single Life Annuity in the amount set forth in Article IV.

1.27A “Qualified Military Service” means any service in the uniformed services (as defined in chapter 43 of title 38, United States Code) where the Participant’s right to reemployment is protected by law.

1.34 “Required Beginning Date” means April 1 of the calendar year following the later of (a) the calendar year in which the Participant attains Age 70-1/2; or (b) in the case of a Participant who is not a 5% owner (within the meaning of Section 416(i) of the Code), the calendar year in which the Participant’s Separation from Service occurs. Notwithstanding the foregoing, a Participant who is not a 5% owner (as defined above), reached age 70-1/2 in 1999 or 2000, and has not incurred a Separation from Service may elect April 1, 2000 or April 1, 2001, respectively, as his Required Beginning Date.

1.35 “Separation from Service” means the termination of an Employee’s status as an Employee or any absence of an Employee in Employment which is not described in Section 1.22.

1.36 “Single Life Annuity” means a form of pension benefit under which payments begin on the date provided in Article IV and end on the first day of the month following the month in which the Participant’s death occurs.

1.37 “Social Security Retirement Age” means (a) for any individual born before January 1, 1938, Age 65, (b) for any individual born after December 31, 1937, but before January 1, 1955, Age 66, or (c) for any individual born after December 31, 1954, Age 67.

1.38 “Spouse” means the individual who is a husband or wife of a Participant as the result of a legal union between one man and one woman, within the meaning of the Defense of Marriage Act.

1.39 “TXU Participant” means a Participant who participated in the TXU Pension Plan immediately prior to the closing date of the acquisition of TXU by the company and whose benefit under the TXU Pension Plan was determined using the final average pay formula (and not the cash balance plan formula).

1.40 “Vesting Computation Period” means a calendar year.

1.41 “Vesting Year” means a credit awarded as follows, subject to Article VI:

(a) Each Employee as of December 31, 1975, shall be credited with a number of Vesting Years equal to his years of service (with fractions rounded to the next full year) under the Plan as in effect on that date.

(b) Each Employee shall be credited with one Vesting Year for each Vesting Computation Period after 1975 in which he completes 1,000 or more Hours of Service.

(c) If an Employee is credited with an Eligibility Year for an Eligibility Computation Period that overlaps two Vesting Computation Periods, but he is not credited with a Vesting Year for either of those Vesting Computation Periods, the Employee shall be credited with one Vesting Year. An Employee may have only one Vesting Year to his credit under this Paragraph at any time.

(d) An Employee shall be deemed to have completed a Vesting Year when he completes his one-thousandth Hour of Service in the relevant Vesting Computation Period.

1.42 The masculine gender shall include the feminine.

ARTICLE II Participation.

2.1 Each Eligible Employee who is covered by the Plan as of December 31, 1975 shall be an Active Participant as of January 1, 1976.

2.2 Each other Eligible Employee shall become an Active Participant on the later of January 1, 1976 or January 1 of the first Eligibility Computation Period in which he completes 1,000 Hours of Service.

2.3 If a former Eligible Employee is not an Eligible Employee on the date on which he would otherwise become an Active Participant under Section 2.2, he shall not then become an Active Participant but shall become an Active Participant on the first day thereafter on which he is an Eligible Employee, provided that if he has a Separation from Service before becoming an Active Participant, Section 6.4 shall apply.

2.4 Participation Freeze for Power Team Employees. Notwithstanding the foregoing, all participation in the Plan by Power Team Employees shall be frozen as of the date the Employee becomes a Power Team Employee.

2.5 Participation Freeze for EIS Senior Management Employees. Notwithstanding the foregoing, all participation in the Plan by EIS Senior Management Employees shall be frozen as of October 31, 1999, or the date such Participant becomes an EIS Senior Management Employee, if later, and no Employee who is an EIS Senior Management Employee shall be eligible to become a Participant in the Plan after October 31, 1999.

2.6 Participation Freeze for all Employees after December 31, 2000. Notwithstanding anything herein to the contrary, but subject to the provisions of Section 2.10 or 2.11, no Employee who is not a Participant on December 31, 2000 shall be eligible to participate in the Plan after December 31, 2000.

2.7 Transfer of Employment to or Reemployment in Positions Eligible for Participation in the Plan or the Commonwealth Edison Company Service Annuity System by Certain Individuals Who Were Participants in Such a Plan on December 31, 2000. If a Participant who was a Participant on December 31, 2000 transfers employment to or is reemployed by the Company or an Affiliate in a job classification with respect to which similarly situated employees of the Company or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in the Commonwealth Edison Company Service Annuity System (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Commonwealth Edison Company Service Annuity System. If a participant in the Commonwealth Edison Company Service Annuity System who was a participant in such plan on December 31, 2000 transfers employment to or is reemployed by the Company or an Affiliate in a management job classification with respect to which similarly situated employees of the Company or Affiliate are eligible to participate in the Plan (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a participant in the Commonwealth Edison Company Service Annuity System and shall not participate in the Plan.

2.8 Pension Choice Election.

(a) In General. Each Participant who is, as of January 1, 2002, an Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (i) continue participating in the Plan on and after January 1, 2002 or (ii) cease participating in the Plan as of December 31, 2001 and begin participating in the Exelon Corporation Cash Balance Pension Plan as of January 1, 2002. Each Eligible Employee who elects to continue participating in the Plan or who is offered and fails to make any such election shall continue to be a Participant as of January 1, 2002. Each Eligible Employee who elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participation in this Plan shall cease participation in the Plan as of December 31, 2001 and shall not be entitled to any benefit under the Plan, unless such Participant receives a notification (the "Notice") from the Company that his employment with the Company and the Affiliates will be terminated on or before December 31, 2002 and that such Participant is eligible for benefits under Article IVE of the Plan or any severance plan maintained by the Company or an Affiliate. An Eligible Employee who receives a Notice shall continue to be a Participant in the Plan until his Separation from

Service, notwithstanding such Eligible Employee's election to participate in the Exelon Corporation Cash Balance Pension Plan. An Eligible Employee (i) who receives a Notice, but whose employment does not terminate on or before December 31, 2002, or (ii) whose employment terminates before December 31, 2002 without the Employee receiving a Notice, shall cease participation in the Plan as of December 31, 2001 if such Employee elects, in the time and manner prescribed by the Administrator, to participate in the Exelon Corporation Cash Balance Pension Plan.

Effective as of January 1, 2004, each Eligible Employee who (i) was eligible to participate in the Plan as of December 31, 2000, (ii) ceases to be a Power Team Employee as of January 1, 2004 because such Eligible Employee is no longer eligible to participate in the performance share award program for Power Team employees under the Exelon Corporation Long Term Incentive Plan and (iii) did not previously make a valid election pursuant to the preceding paragraph shall be permitted to elect, in the time and manner prescribed by the Committee, to either (i) participate in the Exelon Corporation Cash Balance Pension Plan in lieu of this Plan as of January 1, 2004 or (ii) continue or resume participation in the Plan as of January 1, 2004. Each such Eligible Employee who affirmatively elects to continue or resume participation in this Plan in lieu of participation in the Exelon Corporation Cash Balance Pension Plan shall continue or resume participation in this Plan as of January 1, 2004.

(b) Transfer of Benefits and Assets to Cash Balance Pension Plan. If an Eligible Employee described in paragraph (a) above elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participating in the Plan, the Employee's pension, determined as of December 31, 2001, or December 31, 2003, as the case may be, based on the Employee's Benefit Years, Compensation and average annual base salary as of such date, shall be transferred to the Exelon Corporation Cash Balance Pension Plan, and such Employee shall not accrue any additional benefit under the Plan. An amount of assets that is equal to the present value of the Participant's pension described in the preceding sentence, determined using the methods and assumptions prescribed by Section 4044 of ERISA, shall also be transferred to the Exelon Corporation Cash Balance Pension Plan. Such transfer of benefits and assets related thereto shall occur as soon as administratively practicable after the Eligible Employee makes the election described in paragraph (a) above. In the event that an Eligible Employee whose pension and related assets are transferred to the Exelon Corporation Cash Balance Pension Plan receives a Notice and has a Separation from Service on or before December 31, 2002, the pension and related assets that were transferred to the Exelon Corporation Cash Balance Pension Plan shall be transferred back to the Plan and the amount of the pension benefit accrued by such Employee during 2002 (if any) shall be determined under the terms of this Plan rather than the Exelon Corporation Cash Balance Pension Plan. Such transfer shall occur as soon as administratively practicable.

2.9 Cessation of Participation. An individual's participation in the Plan shall cease upon the first to occur of (i) the date the individual is no longer eligible to receive a benefit from this Plan or (ii) the individual's Separation from Service if the individual has not completed at least five Vesting Years upon the date of his Separation from Service.

2.10 Rehire of Employees. The following rules shall apply to an Eligible Employee who is rehired by the Company after a Separation from Service and prior to commencing his pension or any benefits under the Exelon Corporation Cash Balance Pension Plan, as applicable:

(a) Rehire Date Before Absence of 5 Consecutive One-Year Breaks in Service. If an Employee terminates employment and is later rehired by the Company before having an absence from employment with the Company and the Affiliates of five consecutive One-Year Breaks in Service, then either: (1) if such Employee was a Participant on the date his employment terminated, such Employee shall be a Participant in the Plan as of his rehire date if he is then an Eligible Employee, or (2) if such Employee was not a Participant on the date his employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant. Notwithstanding clause (1) of the preceding sentence, if an Eligible Employee described in the preceding sentence was not at any time permitted to make the election described in Section 2.8(a) or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Separation from Service, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his pension and related assets transferred to such plan in the manner described in Section 2.8(b).

(b) Rehire Date After Absence of at Least 5 Consecutive One-Year Breaks in Service. If an Employee terminates employment with the Company and the Affiliates and the Employee was not a Participant or was a Participant who did not have a vested pension as of the date his employment terminated, and such Employee is rehired by the Company after having an absence from employment with the Company and the Affiliates of at least five consecutive One-Year Breaks in Service, such Employee shall not be an Eligible Employee and shall not become a Participant upon such rehire. If a Participant with a vested pension terminates employment with the Company and the Affiliates and the Participant is rehired after having an absence from employment with the Company and the Affiliates of at least five consecutive One-Year Breaks in Service, such Participant shall remain a Participant upon his rehire. Notwithstanding the preceding sentence if a Participant described in the preceding sentence was not at any time permitted to make the election described in Section 2.8(a), or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Separation from Service, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his pension and related assets transferred to such plan in the manner described in Section 2.8(b).

(c) Circumstances Permitting Commencement of Pension. Notwithstanding anything contained herein to the contrary, if a Participant terminates employment and is reemployed as an Employee under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring or retirees, such Participant may elect to commence his pension during such period of reemployment if he is otherwise eligible to commence such pension.

(d) Rehire After Receipt of Benefit Under Section 5.11. Notwithstanding anything contained herein to the contrary, an Employee who is reemployed by an Employer after December 1, 2012 and has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 5.11 shall not be eligible to become a Participant pursuant to this Article 2.

2.11 Change in Employment Status or Transfer to Affiliate. Except as otherwise provided herein, if an Employee who was a Participant transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead either eligible to participate in another plan maintained by such Employer or Affiliate or are not eligible to participate in any plan, then such individual shall upon such transfer or reemployment participate in the plan, if any, determined pursuant to rules established by the Company, which rules may be set forth in a Supplement hereto.

2.12 Certain Rehired Employees. Notwithstanding anything contained herein to the contrary, no Employee who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 5.11 shall be eligible to become a Participant pursuant to this Article 2.

2.13 Transfer of Employment to or from Facilities formerly Owned by CEG. Effective as of the Effective Time (as such term is defined in the CEG Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code (each such plan, a "CEG Pension Plan") , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Pension Plan. If a participant in the CEG Pension Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Pension Plan and shall not participate in the Plan.

ARTICLE III Accrual of Benefits.

3.1 Accrued Benefit. Except as otherwise provided in this Article or in Article VI, each Participant shall have an Accrued Benefit equal to one-twelfth of the greater of:

(a) The sum of (1) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (2) 2% of his aggregate Compensation for employment as an Eligible Employee after December 31, 1938, or

(b) The sum of (1) a percentage of his average annual base salary plus, after December 31, 2001, amounts earned (whether paid in the current or subsequent period) under the Exelon Corporation Annual Incentive Award Program for Management Employees, and the Exelon Corporation Quarterly Incentive Award Program (but excluding amounts earned under any other business or group incentive or bonus programs) during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5% plus 1.2% for each of his first forty Benefit Years, and (2) 0.35% of such highest average in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%). (For the purposes of this Paragraph (b), (A) employment during the most recent 5 years shall include absences which are included in Employment, except an absence prior to June 1, 1992 during which an Employee receives benefits under the Company's Disabilitant Plan, and the average annual base salary of an Employee on an included absence shall be calculated as if his base salary continued during any period of such absence for which he did not receive compensation, such salary to be that in effect when such period began, adjusted for increases applicable to his job classification which occur prior to the end of such period, (B) with respect to a Participant who is employed by the Company for less than 60-consecutive months, the Participant's average annual base salary shall be determined by averaging the Participant's annual base salary for each calendar year in which the Participant was at any time an Employee, determined as if the Participant had remained an Employee for the entire year, provided, that, if there are more than 5 such calendar years, the 5 years which result in the highest average will be used, (C) for purposes of determining consecutive months of employment, months in which the Participant performs no services, other than months for which salary is imputed under (A) above, shall be disregarded, (D) annual base salary shall be determined prior to reduction by amounts contributed at the direction of the Employee to the PECO Energy Company Employee Savings Plan, the Exelon Corporation Employee Savings Plan, the PECO Energy Company Employees' Section 125 Plan, the Exelon Corporation Benefits Contributions Options, the Exelon Corporation Flexible Benefits Program, or for Plan Years beginning after December 31, 2001, amounts contributed to a qualified transportation fringe benefit plan under Section 132(f)(4) of the Code, (E) effective January 1, 1990, a Participant's annual base salary shall not include any lump sum payment of his accrued vacation pay or sick pay, nor any severance payment made by the Company or an Affiliate or pursuant to any plan maintained by the Company or any Affiliate), (F) effective January 1, 1996 for purposes of calculating average annual base salary, any raise received during the month shall be deemed to have been received on the first of such month and (G) amounts earned under the Exelon Corporation Annual Incentive Award Program for Management Employees and the Exelon Corporation Quarterly Incentive Award Program shall be credited for the period such amounts are earned, regardless of when such amounts are actually paid).

A Participant's Accrued Benefit, however, shall not be less than the largest early retirement benefit that he could at any time elect to receive under the Plan. For purposes of the preceding sentence, the early retirement benefit that a Participant may elect to receive at any time of reference is the monthly annuity which, assuming he had a Separation from Service on the date of reference, would be payable to him in the form of a Single Life Annuity beginning as of the later of the day ten years prior to his Normal Retirement Date or the first day of the month following the date of reference.

Notwithstanding the foregoing, the Accrued Benefit of a Power Team Employee shall be frozen as of the date the Employee becomes a Power Team Employee and no Power Team Employee shall earn any additional Accrued Benefit under the Plan while the Employee is a Power Team Employee. The calculation of the benefit of a Power Team Employee under subsection (a) and (b) shall be made without regard to any Compensation, annual base salary or earnings attributable to any period while the Employee is a Power Team Employee.

Notwithstanding the foregoing, an EIS Senior Management Employee's Accrued Benefit shall be frozen as of October 31, 1999, or the date such Participant becomes an EIS Senior Management Employee, if later, and no EIS Senior Management Employee shall earn any additional Accrued Benefit under the Plan after such date. The calculation of an EIS Senior Management Employee's benefit under subsection (a) and (b) shall be made without regard to any Compensation, annual base salary or earnings attributable to any period after October 31, 1999, or the date such Participant becomes an EIS Senior Management Employee, if later.

Notwithstanding the foregoing provisions of this Section 3.1, the Accrued Benefit for a TXU Participant shall be equal to the greater of (1) such Participant's accrued benefit under the TXU Pension Plan immediately prior to the closing date of the acquisition of TXU by the Company, and (2) such Participant's Accrued Benefit determined under subsection (b) above, calculated by including compensation earned by the Participant while he was employed by TXU to the extent such compensation would have been included under subsection (b) if TXU had been part of the Company during the relevant time period and by including the years of service that were credited to the Participant under the TXU Pension Plan immediately prior to the closing date of the acquisition of TXU by the Company.

3.2 Minimum Accrued Benefit. Except as provided in Section 6.5:

(a) as a result of the imposition of the $200,000 cap on compensation under Section 401(a)(17) of the Code effective January 1, 1989 pursuant to Section 3.3, the Accrued Benefit of a Section 401(a)(17) Employee determined as of any date on or after January 1, 1989 and prior to January 1, 1994 shall not be less than the sum of:

(1) his Accrued Benefit determined as of December 31, 1988 under the provisions of the Plan as in effect through December 31, 1988; plus

(2) the Participant's Accrued Benefit determined under Section 3.1 based on the Participant's Benefit Years earned on and after January 1, 1989 and before January 1, 1994;

(b) as a result of the reduction of the $200,000 cap on compensation under Section 401(a)(17) of the Code to $150,000 effective January 1, 1994 pursuant to Section 3.3, the Accrued Benefit of a Section 401(a)(17) Employee determined as of any date on or after January 1, 1994 shall not be less than the sum of:

(3) his Accrued Benefit under Section 3.1 as of December 31, 1993 or, to the extent applicable, his Accrued Benefit under Section 3.2(a) as of December 31, 1993, if greater, determined in each case under the provisions of the Plan as in effect through December 31, 1993; provided, however, that, notwithstanding any provision of the Plan to the contrary, base salary for any determination period (as defined in Section 3.3) that is taken into account in determining an Employee's average annual base salary as of December 31, 1993 shall be subject to the Section 401(a)(17) Compensation Limit (as defined in Section 3.3) in effect for 1993; plus

(4) the Participant's Accrued Benefit determined under Section 3.1 based on the Participant's Benefit Years earned on and after January 1, 1994.

For purposes of Section 3.2(a), a 'Section 401(a)(17) Employee' means an Eligible Employee who completes an Hour of Service on or after January 1, 1989 and whose Accrued Benefit as of a date on or after January 1, 1989 and prior to January 1, 1994 is based on annual Compensation or base salary for a determination period (as defined in Section 3.3) beginning prior to January 1, 1989 that exceeds $200,000. For purposes of Section 3.2(b), a 'Section 401(a)(17) Employee' means an Eligible Employee who completes an Hour of Service on or after January 1, 1994 and whose Accrued Benefit as of a date on or after January 1, 1994 is based on annual Compensation or base salary for a determination period (as defined in Section 3.3) beginning prior to January 1, 1994 that exceeds $150,000.

3.3 Application of Section 401(a)(17) Compensation Limit. Annual Compensation taken into account for purposes of Section 3.1(a) (and Articles IVA, IVB and IVC) and annual base salary taken into account for purposes of Section 3.1(b) (and Articles IVA, IVB and IVC) shall not exceed $200,000 ($150,000, effective January 1, 1994), or such other amount as may be applicable under Code Section 401(a)(17) (the 'Section 401(a)(17) Compensation Limit'). Except as provided below, the Section 401(a)(17) Compensation Limit in effect for a calendar year applies to any period, not exceeding 12 months, over which Compensation or base salary is determined ('determination period') and which begins in such calendar year. Annual base salary for any determination period beginning prior to 1989 that is taken into account in determining an Employee's average annual base salary for purposes of determining the Employee's Accrued Benefit as of a date on or after January 1, 1989 but prior to January 1, 1994 shall be subject to the Section 401(a)(17) Compensation Limit in effect for 1989. Annual base salary for any determination period beginning prior to 1994 that is taken into account in determining an Employee's average annual base salary for purposes of determining the Employee's Accrued Benefit as of a date on or after January 1, 1994 shall be subject to the Section 401(a)(17) Compensation Limit in effect for 1994.

If a determination period consists of fewer than 12 months, the Section 401(a)(17) Compensation Limit will be multiplied by a fraction, the numerator of which is the number of months in the determination period, and the denominator of which is 12. For Plan Years beginning before January 1, 1997, the family aggregation rules of Sections 401(a)(17)(A) of the Code, as in effect on December 31, 1996, shall apply.

3.4 Transferred Employees. The Accrued Benefit of a Participant who has ceased to be an Eligible Employee but who is still an Employee shall be calculated on the basis of his Compensation, average annual base salary, Benefit Years, and the formula in effect under this Article III as of the last date on which he is an Eligible Employee.

3.5 Rehired Employees. A Participant who is reemployed as an Employee and who continues, or commences, his pension payments during the period of his reemployment shall, as required to continue pension payments in accordance with the Company's policy regarding the rehiring of retirees, waive participation in, or additional benefits and accruals under the Plan and accordingly, shall not be entitled to accrue any additional benefits under the Plan during his period of reemployment.

ARTICLE IV. Benefits.

4.1 Normal Retirement. If an Active Participant has not already become vested pursuant to Section 4.4, he shall become fully vested in his Accrued Benefit when he attains Age 65, or, if later, upon the fifth anniversary of the date upon which he first became an Active Participant and may retire on his Normal Retirement Date. Upon retiring, the Participant shall be entitled to a monthly annuity that begins as of the first day of the month following the month in which his Normal Retirement Date occurs and is equal to his Accrued Benefit.

4.2 Postponed Retirement.

(a) An employee may continue in service after his Normal Retirement Date. Except as provided in Section 4.11, an Active Participant who continues in service after his Normal Retirement Date shall receive an annuity commencing as of the first day of the month following actual retirement, or as of his Required Beginning Date, if earlier. Such annuity shall be based upon service, Compensation, average annual base salary and Covered Compensation measured as of the date he retires or his Required Beginning Date, whichever applies, and the benefit formula under Section 3.1 in effect as of such date. Effective as of January 1, 2000, the annuity for an Employee whose Retirement Beginning Date is April 1 of the calendar year following the year in which he incurs a Separation from Service shall include an Actuarial Equivalent adjustment to reflect commencement of payments after April 1 following the calendar year in which he attained age 70 ½. The Actuarial Equivalent adjustment described in the preceding sentence shall be made to Participant's Accrued Benefit as of each December 31 following his Required Beginning Date and preceding his Separation from Service, with the last such adjustment made as of his Separation from Service, and for each such year or portion of a year, shall reduce (but not below zero) any increase in the Participant's Accrued Benefit for the year or portion of a year attributable to Benefit Years, Compensation, annual base salary, or changes in Covered Compensation for that year or portion of a year.

(b) Notwithstanding Paragraph (a), effective January 1, 1994, an executive shall continue as an Employee after his Normal Retirement Date only with the consent of the Company or an Affiliate. For purposes of this Paragraph (b), an "executive" means a Participant who:

(1) Is (A) bona fide executive as defined in Title 29 Code of Federal Regulations §§541.1 and 1625.12 or (B) employed in a high policy making position in the Company or an Affiliate within the meaning of Title 29 Code of Federal Regulations §1625.12;

(2) Has attained Age 65;

(3) Has been in a position described in Paragraph (1) for the two-year period immediately prior to his retirement; and

(4) Is entitled to an immediate vested annual retirement pension, commencing at Age 65 (or retirement, if later), from all employee pension, profit sharing, savings and deferred compensation plans sponsored by the Company and all Affiliates which equals, in the aggregate, at least $44,000 (or such other amount as may be prescribed pursuant to Title 29 Code of Federal Regulations §541.1 from time to time). In calculating the annual retirement pension, (A) all benefits shall be adjusted in accordance with regulations prescribed by the Equal Employment Opportunity Commission so that the benefit is the equivalent of a Single Life Annuity (with no ancillary benefits) under a plan to which employees do not contribute and under which no rollover contributions have been made and (B) there shall be excluded from the calculation of the retirement pension amounts attributable to Social Security, employee contributions, contributions of prior employers, rollover contributions, and contributions described in Code §402(e)(3).

(a) If a Participant's Benefit Commencement Date precedes his actual retirement, the pension payable to the Participant shall be determined as of the December 31 preceding his Benefit Commencement Date and adjusted as of January 1 in each calendar year following his Benefit Commencement Date, with the final adjustment to be made as of the date of his actual retirement. Such annual adjustment shall include any increase (but not any decrease) in the Participant's Accrued Benefit, determined in accordance with Article III, as a result of additional Benefit Years and Compensation and changes to average annual base salary, since the Participant's Benefit Commencement Date or the last such annual adjustment, whichever applies.

4.3 Early Retirement.

(a) Effective August 1, 2000, an Active Participant who terminates after he has attained Age 50 and has to his credit at least 10 Vesting Years may retire and shall upon so retiring be entitled to a monthly annuity that begins, at his election, as of the first day of the month following his retirement or as of the first day of any subsequent month, but not after the first month following his Normal Retirement Date. Such election may be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant and in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a). The amount of the annuity under this Subsection 4.3(a) shall be equal to the Participant's Accrued Benefit determined as of his Benefit Commencement Date reduced as follows:

Attained Age at Benefit Commencement Date	Reduction Factor
64–60	1.00
59	0.98
58	0.96
57	0.93
56	0.90
55	0.87
54	0.84
53	0.81
52	0.78
51	0.75
50	0.72

Notwithstanding the foregoing provisions of this subsection (a), effective January 1, 2002, there shall be no reduction to the Accrued Benefit of an Active Participant who is an hourly, nonexempt Eligible Employee and who has attained age 59 at the time of his Benefit Commencement Date.

(b) Notwithstanding any other provision of the Plan to the contrary, a Participant who has ceased to be an Active Participant because he is an EIS Senior Management Employee, or because he has ceased to be an Employee of the Company and has thereupon become an Employee of EIS, shall continue to be treated as an Active Participant for purposes of this Section 4.3 and, effective January 1, 2002, Section 5.3, but not for any other provision of the Plan, so long as (i) he continuously remains an Employee of EIS or a wholly owned subsidiary of EIS and (ii) EIS continuously remains an Affiliate.

(c) Notwithstanding any other provision of the Plan to the contrary, a Participant who has ceased to be an Eligible Employee and Active Participant because he is a Power Team Employee, shall continue to be treated as an Active Participant for purposes of this Section 4.3 and, effective December 31, 1996, Section 5.3, but not for any other provision of the Plan, so long as he continuously remains a Power Team Employee.

4.4 Deferred Annuity. Effective as of August 1, 2000, any Participant who has a Separation from Service prior to satisfying the requirements for retirement under Sections 4.1-4.3 but at a time when he has to his credit at least five Vesting Years shall upon his Separation from Service be entitled to receive a monthly annuity that begins as of the first day of the month following his Normal Retirement Date and is equal to his Accrued Benefit determined as of his Separation from Service. Alternatively, a Participant described in the preceding sentence may, at his election, receive a monthly annuity that begins as of the first day of the month following his fiftieth birthday or, at his option, on the first day of any month thereafter but not after the first month following his Normal Retirement Date that is equal to the Actuarial Equivalent of the Participant's Accrued Benefit determined as of his Separation from Service. Any election of a Benefit Commencement Date prior to Normal Retirement Date made under this Section may be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant and in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a).

4.5 Disabled Eligible Employees. A Participant who has become disabled within the meaning of the Company's Disabilitant benefit plans while an Eligible Employee shall continue to be credited with Benefit Years and Vesting Years during his period of Disabilitant to the extent set forth in Sections 1.7 (relating to Benefit Accrual Computation Period), 1.9 (relating to Benefit Year), 1.22 (relating to Employment) and 1.40 (relating to Vesting Service). If a disabled Participant has met the requirements to receive a pension under any Section of this Article IV (determined as if his Separation from Service had occurred on the date of reference), such Participant may elect as his Benefit Commencement Date any date as may be provided under the applicable Section. If a disabled Participant continues to be credited with Benefit Years after his Benefit Commencement Date, the amount of annuity payable to the Participant shall be determined as of his Benefit Commencement Date and shall be adjusted annually as of January 1 in each calendar year following his Benefit Commencement Date, up to and including the January 1 next following the date the disabled Participant ceases to be credited with Benefit Years. Such annual adjustment shall include any increase (but not any decrease) in the Participant's Accrued Benefit, determined in accordance with Article III, as a result of additional Benefit Years and Compensation and changes to average annual base salary, since the Participant's Benefit Commencement Date or the last such annual adjustment, whichever applies. In addition, such annual adjustment shall be reduced (but not below zero) by the Actuarial Equivalent of any benefit paid to the Participant since his Benefit Commencement Date during any period (a) prior to Normal Retirement Date or (b) after Normal Retirement Date that would have constituted "Section 202(a)(3)(B) Service" under Title 29 Code of Federal Regulations §2530.203-3(c)(1), to the extent not previously taken into account under this Section; provided, however, that the amount, if any, of the benefits paid to the Participant which exceeds the amount the Participant would have received if distribution had been made in the normal form of benefits described in Section 5.1 or 5.2(a), whichever applies to the Participant, shall be disregarded in determining the Actuarial Equivalent of such benefits for purposes of the reduction described in this sentence.

4.6 Maximum Annuity. Notwithstanding any other provision of the Plan to the contrary, the amount of the Participant's annual benefit (as defined below) accrued, distributed or payable at any time under the Plan shall be limited to an amount such that such annual benefit and the aggregate annual benefit of the Participant under all other defined benefit plans maintained by the Employer or any other Affiliate does not exceed the lesser of:

(i) $160,000 (as increased to reflect the cost of living adjustments provided under Section 415(d) of the Code), multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of participation (within the meaning of Treas. Reg. § 1.415(b)-1(g)(1)(ii)) and the denominator of which is 10; or.

(ii) an amount equal to 100% of the Participant's average compensation for the 3 consecutive calendar years in which his compensation was the highest (as determined in accordance with Treas. Reg. § 1.415(b)-1(a)(5)) and which are included in his years of service (within the meaning of Treas. Reg. § 1.415(b)-1(g)(2)(ii)) with the Employers multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of service with the Employers and the denominator of which is 10.

The dollar amount set forth in clause (i) of the preceding paragraph shall be actuarially reduced in accordance with Treas. Reg. § 1.415(b)-1(d) if pension benefits commence prior to the Participant's attainment of age 62. If a Participant's pension benefit payments commence after the Participant's attainment of age 65, such dollar amount shall be actuarially increased in accordance with Treas. Reg. § 1.415(b)-1(e).

A Participant's "annual benefit" shall mean the Participant's accrued benefit payable annually in the form of a straight life annuity, as determined in, and accordance with, Treas. Reg. § 1.415(b)-1(b). If the annual benefit is payable in a form other than a single life annuity, the annual benefit shall be adjusted to the Actuarial Equivalent of a single life annuity using the assumptions of the following sentences; provided, however, that no adjustment shall be required for survivor benefits payable to a surviving Spouse under a Qualified Joint and Survivor Annuity (as described in Section 5.2) to the extent such benefits would not be payable if the Participant's annual benefit were paid in another form.

Effective for Plan Years beginning January 1, 2004 and January 1, 2005, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greater of (i) the amount computed using the interest rate and mortality table used to determine actuarial equivalence under the Plan and (ii) the amount computed using an interest rate assumption of 5.5% and the applicable mortality table under Treas. Reg. § 1.417(e)-1(d)(2) (the "Applicable Mortality Table"). Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greatest of (i) the amount computed using the interest rate and mortality table used to determine actuarial equivalence under the Plan, (ii) the amount computed using an interest rate assumption of 5.5% and the Applicable Mortality Table and (iii) the amount computed using the applicable interest rate under Treas. Reg. § 1.417(e)-1(d)(3) and the Applicable Mortality Table, divided by 1.05. Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit not subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be determined in accordance with Treas. Reg. § 1.415(b)-1(c). An individual's "annual benefit" under any other defined benefit plan maintained by the Employer and Affiliate shall be as determined pursuant to the provisions of Section 415 of the Code and the regulations issued thereunder the terms of such plan.

Notwithstanding the foregoing provisions of this Section, the limitation provided by this Section shall not apply to a Participant who has not at any time participated in a defined contribution plan maintained by any Employer and whose annual benefit under the Plan does not exceed $10,000 multiplied by a fraction (not exceeding 1 and not less than 1/10th) the numerator of which is the Participant's years of service (within the meaning of Treas. Reg. § 1.415(b)-1(g)(2)(ii)) and the denominator of which is 10.

For purposes of this Section, the term "compensation" shall have the meaning set forth in Section 415(c)(3) of the Code and the applicable Regulations, the term "defined contribution plan" shall have the meaning set forth in Treas. Reg. § 1.415(c)-1(a)(2), the term "defined benefit plan" shall have the meaning set forth in Treas. Reg. § 1.415(b)-1(a)(2) and the term "Employer" shall include the Employers and all corporations and entities required to be aggregated with any of the Employers pursuant to Section 414(b) and (c) of the Code as modified by Section 415(h) of the Code. Section 415 of the Code and the Regulations thereunder are hereby incorporated by reference.

4.7 Benefit Commencement Date. Unless the Participant elects otherwise, the pension to which he is entitled under this Article IV or Articles IVA or IVB shall begin within sixty days of the close of the Plan Year in which falls the later of his Normal Retirement Date or his Separation from Service. The failure of the Participant to apply for his benefit pursuant to Section 5.9 by the date prescribed in the preceding sentence shall be deemed an election to defer payment to a later date. Notwithstanding the above, payment of such pension shall begin no later than a Participant's Required Beginning Date, or the first day of the month following the date the Participant first becomes entitled to such pension, if later.

4.8 Post-Retirement Adjustment.

(a) Commencing with installments due September 1, 1978, benefit payments to Participants who retired under Sections 4.1, 4.2 or 4.3, or corresponding prior Sections, prior to January 1, 1978 and their Contingent Annuity Option beneficiaries are increased by 2% for each calendar year of retirement to a maximum of 4%.

(b) Commencing with installments due September 1, 1980, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1980 and their Contingent Annuity Option beneficiaries are increased by 3% for each calendar year of retirement to a maximum of 6%.

(c) Commencing with installments due September 1, 1982, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1982 and their Contingent Annuity Option beneficiaries are increased by 3% for each calendar year of retirement to a maximum of 6%.

(d) Commencing with installments due September 1, 1984, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1984, and their Contingent Annuity Option beneficiaries are increased by 2% for each calendar year of retirement to a maximum of 4%.

(e) Commencing with installments due September 1, 1986, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1986, and their Contingent Annuity Option beneficiaries are increased by 2% for each calendar year of retirement to a maximum of 4%.

(f) Commencing with installments due February 1, 1991, benefit payments to:

(1) Participants who retired under Section 4.1, 4.2 or 4.3 of the Plan (or corresponding prior Sections) prior to January 1, 1990;

(2) Contingent Annuity Option beneficiaries of deceased Participants who died or retired under the foregoing provisions prior to January 1, 1990;

(3) Qualified Joint and Survivor Annuity beneficiaries of deceased Participants who retired under the foregoing provisions prior to January 1, 1990; and

(4) surviving Spouses receiving benefits under Section 5.4 due to the death of a Participant while an Active Participant prior to January 1, 1990, are increased by a factor of 3/4 of 1% multiplied by the difference obtained by subtracting the Participant's year of retirement or death, as appropriate, from 1990. A Participant or beneficiary described in this Paragraph (f) may irrevocably elect to waive this increase in benefit payments by written notice to the Company made no later than 60 days after the Participant or beneficiary is first notified of the increase by the Company.

(g) Commencing with installments due February 1, 1997, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1994, and Contingent Annuity Option beneficiaries of deceased Participants who died or retired under the foregoing provisions of the Plan prior to January 1, 1994, are increased by fifty dollars ($50) per month.

(h) Commencing with installments due January 1, 2000, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1994, and Contingent Annuity Option beneficiaries of deceased Participants who died or retired under the foregoing provisions of the Plan prior to January 1, 1994, are increased by fifty dollars ($50) per month.

4.9 Special Early Retirement Benefit. The annuity (and any Contingent Annuity Option benefit) of a Participant who retires under the early retirement provisions of Section 4.3 between February 1, 1978 and June 1, 1978, inclusive, shall be computed without the 4% per year reduction described in the last sentence of Section 4.3. In addition, the monthly benefit paid to such a Participant (but not the benefit to any Contingent Annuity Option beneficiary) shall be supplemented by a monthly payment equal to the Social Security old age insurance benefit to which the Participant would be entitled at Age 65 based on earnings received as an Employee of the Company, assuming he has no wages for Social Security purposes after his retirement and there is no change in the Social Security law or rates subsequent to his retirement. The supplemental benefit described in the preceding sentence shall end with the payment on the first day of the month preceding the month in which the Participant first receives (or could have received if he had applied) Social Security old age insurance benefits unreduced on account of age, or with the payment last preceding the Participant's death, if earlier. The special benefits described in this Section shall also be paid with respect to a Participant who elects early retirement during the period February 1, 1978 through June 1, 1978, inclusive, but whose actual retirement is postponed at the request of the Company in order to provide for personnel replacement and training.

4.10 Minimum Annuity. The annuity of a Participant who retires or has retired under Sections 4.1, 4.2 or 4.3, or corresponding prior Sections regardless of the form of his benefit under Article V, and who is not at any time a Highly Compensated Employee, shall not be less than $150 per month.

4.11 Suspension of Benefits. With respect to any Participant whose employment by the Company or an Affiliate continues past his Normal Retirement Date, or who is receiving benefits under the Plan and again becomes an Employee, the following rules shall apply:

(a) If the reemployed Participant has not reached his Normal Retirement Date, his pension shall be suspended and recomputed under the Plan upon his subsequent Separation from Service.

(b) If the Participant has reached his Normal Retirement Date, for each calendar month or for each four or five week payroll period ending in a calendar month during which the Participant either completes forty or more Hours of Service (counting each day of Employment as five Hours of Service), or receives payment for any such Hours of Service performed on each of eight or more days or separate work shifts in such month or payroll period, (referred to herein as "Suspension Service") no pension payment shall be made, and no adjustment to the Participant's pension shall be made on account of such non-payment. No payment shall be withheld pursuant to this Paragraph (b) until the Employee is notified by personal delivery or first class mail during the first calendar month or payroll period in which payments are suspended that his benefits are suspended. Such notification shall contain a description of the specific reasons why benefit payments are being suspended, a general description of the Plan provisions relating to the suspension of payments and a copy of such provisions (or a reference to the relevant pages of the summary plan description providing such information), and a statement to the effect that applicable Department of Labor Regulations may be found in Section 2530.203-3 of the Code of Federal Regulations. In addition, the suspension notification shall inform the Employee of the Plan's procedure for affording a review of the suspension of benefits.

(c) The pension of a reemployed Participant whose benefits were suspended under this Section 4.11 shall begin again no later than the earlier of (1) the first day of the third month following the month in which the Participant first fails to satisfy the service requirements described in Paragraph (b) or has a Separation from Service or (2) his Required Beginning Date. The resumed pension shall be recalculated to reflect Compensation, average annual base salary and Benefit Years earned under the Plan as in effect during such period of reemployment and shall be reduced by the

Actuarial Equivalent of any payment received by the Employee under the Plan prior to his Normal Retirement Date; provided, however, that in no event shall the Participant's monthly pension payable in the form of a single life annuity when reemployment ends be less than the monthly pension that was payable to the Participant in the form of a single life annuity prior to his period of reemployment. The full amount of the resumed pension shall be paid in the form determined pursuant to Article V at the time payments are resumed, without regard to the form of payment in effect for the Participant prior to his reemployment. The pension of any Participant whose employment continued past his Normal Retirement Date (and whose benefits are not suspended because of employment as described in Paragraph (b)) shall be paid pursuant to Section 4.2.

(d) Notwithstanding the foregoing provisions of this Section 4.11, a Participant who received a pension while the Participant worked for Linden Chapel Corporation (formerly known as VSI Group, Inc., a Maryland corporation) before the assets of Linden Chapel Corporation (formerly known as VSI Group, Inc., a Maryland corporation) were acquired by EIS or its Affiliate, shall not have his pension suspended under this Section 4.11 solely as a result of the acquisition of the assets of Linden Chapel Corporation (formerly known as VSI Group, Inc., a Maryland corporation) by EIS or its Affiliate, so long as the Participant remains continuously employed thereafter by the Company or an Affiliate. Notwithstanding the foregoing provisions of this Section 4.11, this Section 4.11 shall not apply to a Participant who is reemployed by an Affiliated Company that does not maintain a defined benefit pension plan.

(e) Notwithstanding the foregoing provisions of this Section 4.11, a reemployed Participant who is employed under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees shall not have his pension suspended under this Section 4.11 nor shall such reemployed Participant be prohibited from commencing his pension if he is otherwise eligible to commence such pension.

4.12. Benefit Restrictions as a Result of Funding. (a) Notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's "Adjusted Funding Target Attainment Percentage" (the "AFTAP"), as defined in Section 436(j) of the Code, is at or below the following levels.

(i) If the Plan's AFTAP is 60% or greater but less than 80% for a Plan Year, the Plan shall not pay any prohibited payment (as defined in Section 4.12(a)(iv)) after the valuation date for the Plan Year to the extent the amount of the payment exceeds the lesser of (x) 50% of the amount of the payment which could be made without regard to the restrictions under this subsection 4.13 and (y) the present value (determined pursuant to guidance prescribed by the Pension Benefit Guaranty Corporation, using the interest and mortality assumptions under Section 417(e) of the Code) of the maximum guarantee with respect to the Participant under Section 4022 of ERISA. Notwithstanding the preceding sentence, only one such prohibited payment may be made with respect to any Participant during any period of consecutive Plan Years to which the limitations under either clause (x) or (y) of the preceding sentence apply. For purposes of this Section 4.12(a)(i), a Participant, his beneficiary and any alternate payee (as defined in Section 414(p)(8) of the Code) shall be deemed a single "Participant."

(ii) If the Plan's AFTAP is less than 60% for a Plan Year, the Plan shall not pay any prohibited payment after the valuation date for the Plan Year.

(iii) During any period in which the Company is a debtor in a case under Title 11, United States Code (or similar federal or state law), the Plan shall not make any prohibited payment. The preceding sentence shall not apply on or after the date on which the Plan's enrolled actuary certifies that the AFTAP is not less than 100%.

(iv) For purposes of this Section 4.12(a), the term "prohibited payment" means (x) any payment, in excess of the monthly amount paid under a single life annuity (plus any social security supplements described in the last sentence of Section 411(a)(9) of the Code) to a Participant or beneficiary whose annuity starting date (as defined in Section 417(f)(2) of the Code and any regulations promulgated thereunder) occurs during any period a limitation under Section 4.12(a)(ii) or (iii) is in effect, (y) any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or (z) any other payment specified by the Secretary of the Treasury by regulations.

(b) In any Plan Year in which the Plan's AFTAP for such Plan Year is less than 60%, benefit accruals under the Plan shall cease as of the valuation date for the Plan Year. This restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company of a contribution (in addition to any minimum required contribution under Section 430 of the Code) equal to the amount sufficient to result in an AFTAP of 60%.

(c) No amendment which has the effect of increasing Plan liabilities by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accruals or the rate at which benefits become nonforfeitable shall take effect during any Plan Year if the Plan's AFTAP for such Plan Year is less than 80% or would be less than 80% after taking into account such amendment; provided, however, that the preceding restriction shall not apply to an amendment which provides for an increase in benefits under a formula which is not based on a Participant's compensation if the rate of such increase is not in excess of the contemporaneous rate of increase in average wages of Participants covered by the amendment; and provided, further, that such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year (or if later, the effective date of the amendment), upon payment by the Company of a contribution as described in Section 436(c)(2) of the Code.

(d) The Plan shall not provide an unpredictable contingent event benefit payable with respect to any event occurring during any Plan Year if the AFTAP for such Plan Year is less than 60% or would be less than 60% after taking into account such occurrence; provided, however, such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company of a contribution as described in Section 436(b)(2) of the Code. For purposes of this Section 4.12(d), the term “unpredictable contingent event benefit” means any benefit payable solely by reason of a plant shutdown (or similar event, as determined by the Secretary of the Treasury), or any event other than the attainment of any age, performance of any service, receipt or derivation of any compensation, or occurrence of death or disability.

(e) To avoid benefit restrictions, the Company may take any action permitted by Section 436 of the Code and the regulations promulgated thereunder.

(f) The provisions of this Section 4.12 are intended to comply with Section 436 of the Code and any regulations promulgated thereunder, and shall be construed to comply therewith.

4.13. Participant’s Death During Qualified Military Service. Effective January 1, 2007, in the case of a Participant who dies while performing Qualified Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any (other than benefit accruals relating to the period of Qualified Military Service), provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant’s death.

ARTICLE IVA. Special Limited Duration Early Retirement Benefit.

4A.1 Eligibility.

(a) The special limited duration early retirement benefit described in Section 4A.3 shall be available to any Active Participant who:

(1) as of December 31, 1990, has attained Age 50 and has to his credit at least five Benefit Years; and

(2) makes a Special Early Retirement Election in accordance with the provisions of Section 4A.2 and does not withdraw such Election on or before September 15, 1990 as provided in Section 4A.2(b).

(b) The Accrued Benefit of an Active Participant who satisfies the requirements of Paragraph (a)(1) above and who dies after July 14, 1990, but before September 16, 1990, shall be calculated under Section 4A.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 or 5.4, notwithstanding his failure to satisfy the requirement of Paragraph (a)(2) above.

4A.2 Special Early Retirement Election.

(a) for the purposes of this Article, a "Special Early Retirement Election" is a written election that:

(1) is submitted to the Plan Administrator on or after July 15, 1990 and on or before September 15, 1990; and

(2) that indicates the Active Participant's intent to retire from employment with the Company:

(A) if the Active Participant elects to participate in the Company's Service Completion Plan, on his "Service Completion Date" (as defined in Section 4A.4(c)(2) below); or

(B) if the Active Participant does not elect to participate in the Company's Service Completion Plan, on August 1, 1990, September 1, 1990, or October 1, 1990;

provided, however, that the election described in Section 4A.2(a)(2)(A) shall not be available to an Active Participant described in Section 4A.4(c)(1)(B).

(b) An Active Participant's Special Early Retirement Election shall become irrevocable as of September 15, 1990 if it has not been withdrawn by the Active Participant on or before such date.

4A.3 Benefits. Notwithstanding anything to the contrary contained in the Plan, each Active Participant who satisfies the requirements of Section 4A.1 shall be entitled to retire on the following terms:

(a) (1) Notwithstanding the provisions of Section 3.1, each Active Participant who satisfies the requirements of Section 4A.1 shall have an Accrued Benefit equal to one-twelfth of the greater of:

(A) the sum of (i) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (ii) 2% of his aggregate Compensation for employment after December 31, 1938, or

(B) the sum of (i) a percentage of his average annual base salary during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5%, plus 1.2% multiplied by the sum of five plus his number of Benefit Years determined as of his Separation from Service (to a maximum of 45), and (ii) 0.35% of such highest average annual base salary in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%);

(2) Notwithstanding the above, the Accrued Benefit of an Active Participant who satisfies the requirements of Section 4A.1 shall not exceed the maximum amount permissible under Sections 401(l) and 415 of the Code when such limitations are applied as follows:

(A) The limitations of Sections 401(l) and 415 shall be applied in the following order of priority: (I) prior to August 3, 1992, the ten-year phase-in limitation applicable to changes in the benefit structure under Section 415(b)(1)(5)(D) of the Code; (II) the limitations on the maximum excess allowance applicable when unreduced benefits are payable prior to social security retirement age as described under Section 401(l)(5)(F)(i) of the Code; and (III) the limitation described in Section 415(b)(1) of the Code;

(B) The ten-year phase-in limitation described in Subsection (A)(I) above shall apply to changes in benefits resulting from the crediting of five additional Benefit Years under Section 4A.3(a)(1)(B)(I); provided, however, that such limitation shall cease to apply on and after August 3, 1992;

(C) The limitations on the maximum excess allowance described in Subsection (A)(II) above shall apply only to such Participants who are Highly Compensated Employees at any time after 1989 and prior to Separation from Service; and

(D) For purposes of the limitations described in Subsections (A)(I) and (A)(III) above, the following actuarial assumptions shall be used to determine adjusted limitations for Participants whose benefit payments commence prior to Age 55: (I) 5% interest; and (II) the 1971 Forecast Mortality Table with a one-year age rating.

(3) For the purposes of Section 4A.3(a)(1)(B) above:

(A) employment during the most recent five years shall include absences which are included in Employment, except an absence during which an Employee receives benefits under the Company's Disabilitant Plan, and the average annual base salary of an Employee on an included absence shall be calculated as if his base salary continued during any period of such absence for which he did not receive Compensation, such salary to be that in effect when such period began, adjusted for increases applicable to his job classification which occur prior to the end of such period;

(B) for any 12-consecutive-month period taken into account in determining a Participant's average annual base salary, a Participant's annual base salary shall not exceed $200,000 (or such other amount as may apply under Section 401(a)(17) of the Code for the calendar year in which the last of such 12-consecutive-month periods ends.) In determining annual base salary, the family aggregation rules of Section 401(a)(17)(A) of the Code, as in effect prior to January 1, 1997, shall apply.

(C) a Participant's annual base salary shall not include any lump sum payment of accrued vacation or sick pay, nor any severance payment made by the Company or an Affiliate or pursuant to any plan maintained by the Company or an Affiliate.

(b) for the purposes of determining the date as of which the Active Participant may commence receiving his pension pursuant to Article IV, and his ability to elect a Contingent Annuity Option pursuant to Section 5.3, the Active Participant:

(1) shall be credited with his actual number of Vesting Years as of his Separation from Service, plus five Vesting Years; and

(2) shall be deemed to be his actual Age as of the later of his Separation from Service or December 31, 1990, plus five years; provided, however, that the Actuarial Equivalent of his Accrued Benefit shall be calculated based on his actual Age as of his Benefit Commencement Date.

(c) If the Participant's annuity (including any Contingent Annuity Option benefit) is paid pursuant to Section 4.3, such annuity shall be computed without regard to the 4% per year reduction described in the last sentence of such Section.

4A.4 Special Rules. Notwithstanding anything to the contrary contained in the Plan:

(a) The minimum pension payable to an Active Participant who makes a Special Early Retirement Election shall be equal to the pension otherwise payable to him under the Plan, determined without regard to the provisions of this Article IVA (other than the limitations described in Section 4A.3(a)(2)), multiplied by one hundred five percent (105%).

(b) If, at the time of making a Special Early Retirement Election under Section 4A.2, an Active Participant elects any Contingent Annuity Option, the election of such option shall become effective immediately.

(c) The following additional definitions shall apply for purposes of this Article IVA:

(1) An "Active Participant" shall mean an Active Participant as defined in Section 1.2, including (A) a Participant who is an Eligible Employee at least one day on or after July 15, 1990 and on or before September 15, 1990 and (B) a Participant not described in (A) who is absent from Employment by reason of his Disabilitant on account of illness or accident.

(2) An Active Participant's "Service Completion Date" shall be the date specified by the Company as the date as of which his services will no longer be required by the Company. In no event, however, will any Active Participant's Service Completion Date be later than December 1, 1992. Each Active Participant who makes a Special Early Retirement Election shall receive written notification from the Company on or before December 1, 1990 specifying the calendar quarter in which or the date on which his services will no longer be required by the Company.

ARTICLE IVB. Nuclear Voluntary Retirement Incentive Plan.

4B.1 Eligibility.

(a) The voluntary retirement incentive plan benefit described in Section 4B.3 shall be available to any Participant who:

(1) as of December 1, 1992 is on the Nuclear Group payroll;

(2) as of March 31, 1993, will have attained Age 50 and have to his credit at least 5 Benefit Years; and

(3) makes a Voluntary Early Retirement Election in accordance with the provisions of Section 4B.2 and does not withdraw such Election as provided in Section 4B.2(b).

(b) The Accrued Benefit of a Participant who satisfies the requirements of Paragraphs (a)(1) and (2) above and who dies after December 9, 1992, but before January 26, 1993, shall be calculated under Section 4B.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 or 5.4, notwithstanding his failure to satisfy the requirement of Paragraph (a)(3) above.

4B.2 Voluntary Early Retirement Election.

(a) For the purposes of this Article, a "Voluntary Early Retirement Election" is a written election that:

(1) is submitted to the Plan Administrator on or after December 10, 1992 and on or before January 25, 1993, together with a signed full waiver and release of claims form; and

(2) indicates the Participant's intent to retire from employment with the Company on March 1, 1993, May 1, 1993 or July 1, 1993, as prescribed for the Participant in the personal election form provided to the Participant by the Company.

(b) A Participant's Voluntary Early Retirement Election shall become irrevocable if it is not withdrawn by the Participant, in writing in a form acceptable to the Plan Administrator, within seven (7) days following the date such Voluntary Early Retirement Election is submitted to the Administrator by the Participant.

4B.3 Benefits. Notwithstanding anything to the contrary contained in the Plan, each Participant who satisfies the requirements of Section 4B.1 shall be entitled to retire on the following terms:

(a) (1) Notwithstanding the provisions of Section 3.1 (other than the last sentence of Section 3.1(b)), each Participant who satisfies the requirements of Section 4B.1 shall have an Accrued Benefit equal to one-twelfth of the greater of:

(A) the sum of (I) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (II) 2% of his aggregate Compensation for employment after December 31, 1938, or

(B) the sum of (I) a percentage of his average annual base salary during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5%, plus 1.2% multiplied by the sum of five plus his number of Benefit Years determined as of his Separation from Service (to a maximum of 45 Benefit Years), and (II) 0.35% of such highest average annual base salary in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%);

(2) Notwithstanding the above, the Accrued Benefit of a Participant who satisfies the requirements of Section 4B.1 shall not exceed the maximum amount permissible under Sections 401(l) and 415 of the Code when such limitations are applied as follows:

(A) The limitations of Sections 401(l) and 415 shall be applied in the following order of priority: (I) the limitations on the maximum excess allowance applicable when unreduced benefits are payable prior to social security retirement age as described under Section 401(l)(5)(F)(i) of the Code; and (II) the limitation described in Section 415(b)(1) of the Code;

(B) The limitations on the maximum excess allowance described in Subparagraph (A)(I) above shall apply only to such Participants who are Highly Compensated Employees at any time after 1991 and prior to Separation from Service; and

(C) For purposes of the limitation described in Subparagraph (A)(II) above, the following actuarial assumptions shall be used to determine the adjusted limitation for Participants whose benefit payments commence prior to Age 62: (I) 5% interest; and (II) the 1971 Forecast Mortality Table with a one-year age rating.

(3) For purposes of Section 4B.3(a)(1) above, for any 12-consecutive-month period taken into account in determining a Participant's average annual base salary, a Participant's annual base salary shall not exceed $200,000 (or such other amount as may apply under Section 401(a)(17) of the Code for the calendar year in which the last of such 12-consecutive-month periods ends). In determining annual base salary, the family aggregation rules of Section 401(a)(17)(A) of the Code, as in effect prior to January 1, 1997, shall apply.

(b) For the purposes of determining the date as of which the Participant may commence receiving his pension pursuant to Article IV, and his ability to elect a Contingent Annuity Option pursuant to Section 5.3, the Participant:

(1) shall be credited with his actual number of Vesting Years as of his Separation from Service, plus 5 Vesting Years; and

(2) shall be deemed to be his actual Age as of the later of his Separation from Service or March 31, 1993, plus 5 years; provided, however, that the Actuarial Equivalent of his Accrued Benefit shall be calculated based on his actual Age as of his Benefit Commencement Date.

(c) If the Participant's annuity (including any Contingent Annuity Option benefit) is paid pursuant to Section 4.3, such annuity shall be computed without regard to the 4% per year reduction described in the last sentence of such Section.

4B.4 Special Rules. Notwithstanding anything to the contrary contained in the Plan, if, at the time of making a Voluntary Early Retirement Election under Section 4B.2, a Participant elects any Contingent Annuity Option, the election of such option shall become effective immediately.

ARTICLE IVC. Voluntary Retirement Incentive Program.

4C.1 Eligibility.

(a) The voluntary retirement incentive program benefit described in Section 4C.3 shall be available to any Participant who:

(1) is an Eligible Employee employed on a regular, part-time or intermittent basis, whether actively employed or absent under circumstances included in Employment, during the period beginning on July 5, 1994 and ending on September 16, 1994, other than an Eligible Employee who is laid off due to loss of employment qualifications and whose recall period ends prior to the date described for the Eligible Employee in Section 4C.2(a)(2);

(2) was born before January 1, 1946, became an Eligible Employee before January 1, 1991, and, as of December 31, 1995, will have to his credit at least 5 Benefit Years;

(3) makes a Voluntary Early Retirement Election in accordance with the provisions of Section 4C.2 and does not withdraw such Election as provided in Section 4C.2(b); and

(4) continues in employment with the Company in the same position (unless transferred at the direction of the Company) until, but not beyond, the date described in Section 4C.2(a)(2); provided, however, that this requirement shall not apply in the event the Participant ceases active employment with the Company (which shall apply to both direct and indirect employment (e.g., a leased employee)) earlier (A) due to a Disabilitant on account of illness or accident during which the Participant is eligible for and receives Disabilitant benefits under a Disabilitant benefit plan sponsored by the Company; (B) because the Company declares the Participant excess before the date described for the Participant in Section 4C.2(a)(2); or (C) because the Company has discharged the Participant for any reason, other than for willful misconduct, on or after July 5, 1994.

(b) (1) The Accrued Benefit of a Participant who satisfies the requirements of Paragraphs (a)(1) and (a)(2) above and who dies after July 4, 1994, but before September 17, 1994, shall be calculated under Section 4C.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 (but not Section 5.4), notwithstanding his failure to satisfy the requirements of Paragraph (a)(3) and/or (a)(4) above.

(2) The Accrued Benefit of a Participant who satisfies the requirements of Paragraphs (a)(1), (a)(2) and (a)(3) above and who dies after July 4, 1994, but before the date described for the Participant in Section 4C.2(a)(2), shall be calculated under Section 4C.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 or 5.4, notwithstanding his failure to satisfy the requirements of Paragraph (a)(4) above.

4C.2 Voluntary Early Retirement Election.

(a) For the purposes of this Article, a “Voluntary Early Retirement Election” is a written election that:

(1) is submitted to and accepted by the Plan Administrator on or after July 5, 1994 and on or before September 16, 1994, together with a signed full waiver and release of claims form; and

(2) indicates the Participant’s intent to retire from employment with the Company (including both direct and indirect employment (e.g., as a leased employee)) on the first of the month following the later of (A) the Participant’s release date determined from the table below or (B) the date the Participant attains Age 50.

STRATEGIC BUSINESS UNIT	RELEASE DATE
CONSUMER ENERGY SERVICE GROUP	
• Majority (except below	• 12/31/94
• Gas Utilization Job Family	• 3/31/95
NUCLEAR	
• Majority (except below)	• 12/31/94
• Limerick (other than below)	• 12/31/94
• Operations	6/30/95
• Mtce/I&C	6/30/95

STRATEGIC BUSINESS UNIT	RELEASE DATE
• Station Support (other than below)	• 12/31/94
• Mtce/I&C	6/30/95
• Peach Bottom (other than below	• 12/31/94
• Operations	12/31/95
• Mtce/I&C	12/31/95
POWER GENERATION GROUP	
• Majority (except below)	• 12/31/94
• Operations – Cromby Station	• 6/30/95
CENTRAL	
• Information Systems	• 10/31/94
• Human Resources-	• 12/31/94
Benefits Division	6/30/95
• Corp. & Public Affairs	• 12/31/94
• Quality Management	• 12/31/94
• Finance	• 12/31/94
• Legal	• 12/31/94
• Support Services	• 12/31/94
• Gas "Meter Shop"	• 12/31/94
• Gas	• 6/30/95
• Bulk	• 6/30/95

(b) A Participant's Voluntary Early Retirement Election shall become irrevocable if it is not withdrawn by the Participant, in writing in a form acceptable to the Plan Administrator:

(1) within seven (7) days following the date such Voluntary Early Retirement Election is submitted to the Administrator by the Participant, in the case of Elections submitted to the Administrator before September 2, 1994; or

(2) within seven (7) days following the date such Voluntary Early Retirement Election is accepted by the Administrator, in the case of Elections submitted to the Administrator on or after September 2, 1994.

4C.3 Benefits. Notwithstanding anything to the contrary contained in the Plan, each Participant who satisfies the requirements of Section 4C.1 shall be entitled to retire on the following terms:

(a) (1) Notwithstanding the provisions of Section 3.1 (other than the last sentence of Section 3.1(b)), each Participant who satisfies the requirements of Section 4C.1 shall have an Accrued Benefit equal to one-twelfth of the greater of:

(A) the sum of (I) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (II) 2% of his aggregate Compensation for employment after December 31, 1938, or

(B) the sum of (I) a percentage of his average annual base salary during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5%, plus 1.2% multiplied by the sum of three plus his number of Benefit Years determined as of his Separation from Service (to a maximum of 43 Benefit Years), and (II) 0.35% of such highest average annual base salary in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%);

(2) Notwithstanding the above:

(A) the Accrued Benefit of a Participant who satisfies the requirements of Section 4C.1 shall not exceed the maximum amount permissible under Section 415 of the Code. For purposes of this limitation, the following actuarial assumptions shall be used to determine the adjusted limitation under Section 415(b)(1) of the Code for Participants whose benefit payments commence prior to Age 62: (I) 5% interest; and (II) the 1971 Forecast Mortality Table with a one-year age rating.

(B) Plan benefits provided under this Article IVC for Participants described in Section 4C.1 who are Highly Compensated Employees at any time after 1993 shall be limited to the extent necessary to satisfy the nondiscriminatory amount requirements of Section 401(a)(4) of the Code applying the general test described in Treas. Reg. §1.401(a)(4)-3(c) to the portion of the Plan covering Participants described in Section 4C.1.

(3) The Section 401(a)(17) Compensation Limit described in Section 3.3 of the Plan shall apply for purposes of determining benefits under Section 4C.3(a)(1) above; provided, however, that a Participant’s Accrued Benefit shall in no event be less than the amount described in Section 3.2(b).

(b) For purposes of determining the date as of which the Participant may commence receiving his pension pursuant to Article IV, and his ability to elect a Contingent Annuity Option pursuant to Section 5.3, the Participant:

(1) shall be deemed to have completed 10 Vesting Years for purposes of Article IV and shall be deemed to have completed 14 Benefit Years for purposes of Section 5.3; and

(2) shall be deemed to be his actual Age as of his Separation from Service plus 5 years.

(c) If the Participant's annuity (including any Contingent Annuity Option benefit) is paid pursuant to Section 4.3, such annuity shall be computed without regard to the 4% per year reduction described in the last sentence of such Section.

4C.4 Special Rules. Notwithstanding anything to the contrary contained in the Plan, if, at the time of making a Voluntary Early Retirement Election under Section 4C.2, a Participant elects any Contingent Annuity Option, the election of such option shall become effective immediately.

ARTICLE IVD. 1998 Workforce Reduction Program.

4D.1 Purpose. This Article IVD is intended to provide certain Active Participants with additional benefits in recognition of the Company's need to reduce its workforce to address the competitive business conditions facing the Company and the Affiliates. In general, this Article IVD provides additional retirement benefits to Active Participants whose Employment with the Company terminates between June 1, 1998 and June 30, 2000, inclusive, because they have been declared "excess" by the Company.

4D.2 Definitions. The following capitalized terms, when used in this Article IVD, shall have the following meanings, notwithstanding any different definitions of such terms elsewhere in the Plan.

(a) "CTAC Employee" means an Active Participant employed by the Company in a craft, technical, administrative or clerical position.

(b) "Disabled Employee" means an Active Participant who is receiving benefits pursuant to the Company's Disabilitant Plan or Long Term Disabilitant Plan during the period from August 1, 1998, through June 30, 2000, inclusive.

(c) "Election Period" means the 14-day period beginning on the date an Eligible Participant receives a Program enrollment package.

(d) "Eligible Participant" means each PSM Employee, CTAC Employee or Disabled Employee who satisfies the following applicable requirements:

(1) In the case of a Disabled Employee, he is described in Schedule 1 to the Plan and terminates Employment on his Qualified Retirement Date or Qualified Separation Date, whichever is applicable, pursuant to his irrevocable written election to participate in the Program, which election shall be made in the form and manner provided by the Company and during the applicable Election Period.

(2) In the case of a PSM Employee or a CTAC Employee, he continues in Employment with the Company (or an Affiliate) in the same position (unless transferred at the direction of the Company) until, but not beyond, his Qualified Retirement Date or Qualified Separation Date, if any, whichever applies; provided, however, that this requirement shall not apply in the event the PSM Employee or CTAC Employee ceases active employment with the Company (or an Affiliate) earlier due to a Disabilitant on account of illness or accident for which such Employee is eligible for and receives Disabilitant benefits under a Disabilitant benefit plan sponsored by the Company.

(3) In the case of a PSM Employee, he satisfies both (A) and (B), below:

(A) He is declared “excess” by the Company based on the following criteria:

(i) his 1997 job performance; or

(ii) the elimination of his position or a position in his job classification; or

(iii) failure to be selected for an available position.

(B) He does not reject an offer from the Company or an Affiliate to work in a position that is within two salary grades of his current position.

A description of the PSM Employees who are declared “excess” by the Company in accordance with the foregoing criteria is set forth on Schedule 1 to the Plan.

(4) In the case of a CTAC Employee, he satisfies both (A) and (B), below:

(A) He is declared “excess” by the Company based on the following criteria:

(i) his 1997 job performance; or

(ii) the elimination of one or more positions in his job classification, and

(I) if there are multiple positions that are identified as excess in his job classification and the number of such CTAC Employees who elect to participate in the Program exceeds the number identified as excess, his seniority; or

(II) if there are multiple positions that are identified as excess in his job classification and the number of such CTAC Employees who elect to participate in the Program is less than the number identified as excess, the criteria described in the Company’s suspended Reduction in Force Policy.

A description of the CTAC Employees who are declared “excess” by the Company in accordance with the foregoing criteria is set forth on Schedule 1 to the Plan.

(B) In the case of a CTAC Employee described in subclause (iv)(A)(ii) above, either:

(i) he elects in writing, in the form and manner provided by the Company and during the applicable Election Period, to participate in the Program and does not revoke such election within the time period prescribed by the Company; or

(ii) he irrevocably elects in writing not to participate in the Program and the Company subsequently terminates his Employment because he is declared “excess” in accordance with the criteria set forth in paragraph (4)(A) above;

(5) His Employment, if any, is not terminated prior to his Qualified Retirement Date or Qualified Separation Date, if any, because of unsatisfactory job performance or one or more violations of the Company’s Disciplinary Guidelines or Code of Conduct.

(6) He executes a written release and waiver of claims in favor of the Company and the Affiliates in a form provided by the Company and within the time period required by the Company. Such release and waiver of claims shall become irrevocable if it is not withdrawn, in writing in a form acceptable to the Plan Administrator, within seven (7) calendar days following its submission to the Plan Administrator.

(7) His Employment, or his Employer’s status as an Affiliate, is not terminated as a result of a sale of assets or stock, a merger or any other business transaction which provides him an opportunity to be employed by an employer that is not the Company or an Affiliate.

(e) “Program” refers to the enhanced benefits provided pursuant to this Article IVD.

(f) “PSM Employee” means an Active Participant employed by the Company in a professional, supervisory or managerial position.

(g) “Qualified Retirement Date” means the date between June 1, 1998 and June 30, 2000, inclusive, as set forth on Schedule 1 of the Plan, that a Retirement-Eligible Participant may retire from the Company and receive Retirement Benefits.

(h) "Qualified Separation Date" means the date between June 1, 1998 and June 30, 2000, inclusive, as set forth on Schedule 1 of the Plan, that a Separation-Eligible Participant may terminate his Employment and receive Separation Benefits.

(i) "Retirement Benefits" means the benefits described in Section 4D.4.

(j) "Retirement-Eligible Participant" means an Eligible Participant who, as of December 31, 1999:

(1) is Age 50 or older; and

(2) is credited with at least five (5) Vesting Years.

For purposes of this paragraph (j), the Age of an Eligible Participant shall be his actual Age (without regard to the provisions of Section 4D.4).

(k) "SEP Annuity" means an annuity that is the Actuarial Equivalent of the SEP Lump Sum, determined on the basis of the actuarial assumptions applicable under Section 5.6 of the Plan.

(l) "SEP Lump Sum" means a fixed dollar amount equal to the following:

(1) in the case of a Separation-Eligible Participant who has not received payment for the 90-day search period under the Company's Reduction in Force Policy prior to the suspension of that policy, a lump sum equal to the total amount such Separation-Eligible Participant would have received during the 90-day search period under the Company's suspended Reduction in Force Policy if such policy had remained in effect; and

(2) (A) for a Separation-Eligible Participant who has fewer than ten (10) Benefit Years, two (2) multiplied by the number of full or partial Benefit Years as of his Separation from Service, multiplied by his Weekly Base Pay; or

(B) for a Separation-Eligible Participant who has ten (10) or more Benefit Years, three (3) multiplied by the number of full or partial Benefit Years as of his Separation from Service multiplied by his Weekly Base Pay.

Notwithstanding the foregoing, no Separation-Eligible Participant shall be entitled to receive a SEP Lump Sum under clause (2)(A) above that is less than eight (8) multiplied by his Weekly Base Pay.

(m) "Separation Benefits" means the benefits described in Section 4D.5.

(n) “Separation-Eligible Participant” means an Eligible Participant who:

(1) is not a Retirement-Eligible Participant; or

(2) is a Retirement-Eligible Participant who, in accordance with Section 4D.3, elects to receive Separation Benefits.

(o) “Weekly Base Pay” means:

(1) in the case of an Eligible Participant who was compensated on a salaried basis as of May 26, 1998, the Eligible Participant’s weekly base salary as of May 26, 1998, adjusted for any subsequent merit increases (or for a pro rata portion of such merit increases if such increases are based on a greater regularly scheduled workweek than the Eligible Participant’s regularly scheduled workweek as of May 26, 1998);

(2) in the case of an Eligible Participant who was compensated on a non-salaried basis as of May 26, 1998, the number of hours per week such Eligible Participant was regularly scheduled to work as of May 26, 1998 multiplied by his regular hourly rate in effect on the day

4D.3 Elections of the Retirement and Separation Benefits. Any Retirement-Eligible Participant shall be entitled to elect to receive Retirement Benefits or Separation Benefits, but not both. A Retirement-Eligible Participant must submit to the Company’s Human Resources Department a completed and signed election form, in such form and manner and at such time as may be required by the Administrator.

4D.4 Computation of Retirement Benefits Under the Program.

(a) Each Retirement-Eligible Participant who has not elected Separation Benefits in accordance with Section 4D.3 shall be entitled to early retirement benefits determined under Section 4.3 of the Plan, regardless of the number of Vesting Years with which he has been credited; provided, however, that for the purpose of determining any applicable reduction in the amount received upon early retirement, such Participant’s Age on his Benefit Commencement Date shall be deemed to be his actual Age on such date plus 60 additional months.

(b) The Accrued Benefit of a Retirement-Eligible Participant who satisfies the requirements of an Eligible Participant, other than paragraphs 4D.2(d)(2) and 4D.2(d)(6), and who dies before his Qualified Retirement Date, shall be calculated by applying paragraph 4D.4(a) as of the date of his death for purposes of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4D.2(d)(2) and/or 4D.2(d)(6).

4D.5 Computation, Payment and Form of Separation Benefits Under the Program.

(a) Each Separation-Eligible Participant shall be entitled to receive a SEP Annuity in addition to his Accrued Benefit.

(b) A Separation-Eligible Participant shall receive payment of his SEP Annuity in accordance with the following:

(1) A Separation-Eligible Participant shall receive the sum of (I) the Actuarial Equivalent of his SEP Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) and (II) his Accrued Benefit, with such sum payable at such time, in such form and subject to such adjustments as may otherwise be applicable under Articles IV and V of the Plan. In lieu of receiving such Actuarial Equivalent of his SEP Annuity at such time and in such form as he receives his Accrued Benefit, a Separation-Eligible Participant may instead elect to receive immediate payment of his SEP Annuity in accordance with paragraph (2) below or an immediate distribution of his SEP Lump Sum in accordance with paragraph (3) below.

(2) A Separation-Eligible Participant may elect, in accordance with the procedure described in Section 4.3, to receive his SEP Annuity immediately, with payment to begin as of his Qualified Separation Date in the following form:

(A) The SEP Annuity of a Separation-Eligible Participant who is unmarried on his Benefit Commencement Date shall be paid in the form of a Single Life Annuity.

(B) The SEP Annuity of a Separation-Eligible Participant who is married on his Benefit Commencement Date shall be paid in the form of a Qualified Joint and Survivor Annuity.

(3) In lieu of his SEP Annuity, a Separation-Eligible Participant may elect to receive an immediate payment of his SEP Lump Sum, with payment to be made as of his Qualified Separation Date in a single sum. Any such election by a Separation-Eligible Participant who is married on his Benefit Commencement Date shall be subject to the spousal consent requirements described in Section 5.7, shall be made in writing in a manner prescribed by the Company and may be made or revoked at any time within the 90-day period preceding the Benefit Commencement Date but in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a).

(c) In the case of a Separation-Eligible Participant who satisfies the requirements of an Eligible Participant, other than paragraphs 4D.2(d)(ii) and 4D.2(d)(vi), and who dies before his Qualified Separation Date, the Actuarial Equivalent of such Participant's SEP Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) shall be added to his Accrued Benefit for the purpose of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4D.2(d)(ii) and/or 4D.2(d)(vi).

ARTICLE IVE. Merger Separation Program.

4E.1 Purpose. This Article IVE is intended to provide certain Participants with additional benefits in recognition of the Company's need to reduce its workforce in connection with the merger of the Company and Unicom Corporation. In general, this Article IVE provides additional retirement benefits to certain Participants whose Employment with the Company terminates between 60 days after the Merger Date and December 31, 2002, inclusive.

4E.2 Definitions. The following capitalized terms, when used in this Article IVE, shall have the following meanings, notwithstanding any different definitions of such terms elsewhere in the Plan.

(a) "Annuity" means an annuity that is the Actuarial Equivalent of the Lump Sum, determined on the basis of the actuarial assumptions applicable under Section 5.6 of the Plan.

(b) "Disabled Employee" means an Active Participant who is receiving benefits pursuant to the Company's Disabilitant Plan or Long Term Disabilitant Plan at any time during the Merger Separation Period.

(c) "Election Period" means the 45-day period beginning on the date an Eligible Participant receives a Program enrollment package.

(d) "Eligible Participant" means each Participant, other than an intermittent employee, who satisfies the following applicable requirements:

(1) In the case of a Disabled Employee, he terminates Employment on his Qualified Retirement Date or Qualified Separation Date, whichever applies, pursuant to his irrevocable written election to participate in the Program, which election shall be made in the form and manner provided by the Company and during the applicable Election Period.

(2) In the case of a Participant other than a Disabled Employee or a Participant described in (3) below, he satisfies (A) or (B), and each of (C) and (D), below:

(A) His current position is eliminated as part of the restructuring program related to the merger between the Company and Unicom Corporation; or

(B) He is offered a position or a transfer (either between or within business units) as part of the merger between the Company and Unicom Corporation that results in one or more of the following:

(i) an increase in one-way commuting distance of more than 50 miles;

(ii) a substantial change in major position responsibilities and duties, as determined by the Company acting as employer and not as a fiduciary;

(iii) a lower job band; or

(iv) a lower annual base salary.

(C) His position is identified by the Company for elimination, transfer or change, whichever applies, he is notified of such elimination, transfer or change no later than sixty days before December 31, 2002 and, in the case of a transfer described in paragraph (2)(B) above, he elects in writing, in the form and manner provided by the Company and during the Election Period, to participate in the Program.

(D) He continues in Employment with the Company or an Affiliate in the same position (unless transferred at the direction of the Company) until, but not beyond, his Qualified Retirement Date or Qualified Separation Date, if any, whichever applies; provided, however, that this requirement shall not apply in the event the Participant ceases active employment with the Company or an Affiliate earlier due to a disability on account of illness or accident which such Employee is eligible and receives disability benefits under a disability benefit plan sponsored by the Company.

(3) In the case of an Active Participant who is a nonexempt, hourly craft employee, one or more positions in his job classification are eliminated as part of the restructuring program related to the merger between the Company and Unicom Corporation, and

(A) if there are multiple such positions that are eliminated in his job classification and the number of such Active Participants who elect to participate in the Program exceeds the number of positions eliminated, Eligible Participants will be identified based on seniority; or

(B) if there are multiple such positions that arc eliminated in his job classification and the number of such Active Participants who elect to participate in the Program is less than the number of positions eliminated, Eligible Participants will be identified based on the criteria described in the Company's suspended Reduction in Force Policy.

(4) His Employment, if any, is not terminated prior to his Qualified Retirement Date or Qualified Separation Date, whichever applies, for any reason not related to the merger between the Company and Unicom Corporation.

(5) He executes a written release and waiver of claims in favor of the Company and the Affiliates in a form provided by the Company and within the time period required by the Company. Such release and waiver of claims shall become irrevocable if it is not withdrawn, in writing in a form acceptable to the Plan Administrator, within seven (7) calendar days following its submission to the Plan Administrator.

(e) “Enhanced Age” means:

(1) in the case of a Retirement-Eligible Participant, his actual Age plus twelve (12) additional months; and

(2) in the case of a Separation-Eligible Participant, his actual Age plus the number of months included in his Special Payment Period.

(f) “Enhanced Benefit Years” means:

(1) in the case of a Retirement-Eligible Participant, his actual Benefit Years (up to a maximum of 40) plus twelve (12) additional months; and

(2) in the case of a Separation-Eligible Participant, his actual Benefit Years (up to a maximum of 40) plus the number of months equal to one-fourth of the number of weeks included in Section 4E.2(r)(2) (up to a maximum of twenty-four (24) weeks), rounded to the nearest whole number of months (with remainders of one-half(l/2) rounded to the next higher whole number).

(g) “Enhanced Vesting Years” means:

(1) in the case of a Retirement-Eligible Participant, his actual Vesting Years plus twelve (12) additional months; and

(2) in the case of a Separation-Eligible Participant, his actual Vesting Years plus the number of months equal to one-fourth of the number of weeks included in Section 4E.2(r)(2) (up to a maximum of twenty-four (24) weeks), rounded to the nearest whole number of months (with remainders of one-half (1/2) rounded to the next higher whole number).

(h) “Lump Sum” means a fixed dollar amount equal to the following:

(1) in the case of a Retirement-Eligible Participant, 26 multiplied by his Weekly Base Pay; and

(2) in the case of a Separation-Eligible Participant, the sum of (A) and (B) below:

(A) 52 multiplied by his Weekly Base Pay; and

(B) the number of full Vesting Years as of his Qualified Separation Date that are in excess often (10) but not in excess of thirty-six (36), if any, multiplied by his Weekly Base Pay.

(i) “Merger Separation Period” means the time period beginning sixty (60) days before the Merger Date and ending on December 31, 2002, inclusive.

(j) “Program” refers to the enhanced benefits provided pursuant to this Article IVE.

(k) “Qualified Retirement Date” means the date during the Merger Separation Period. as determined by the Company, that a Retirement-Eligible Participant may retire from the Company and receive Retirement Benefits.

(l) “Qualified Separation Date” means the date during the Merger Separation Period, as determined by the Company, that a Separation-Eligible Participant may terminate his Employment and receive Separation Benefits.

(m) “Retirement Benefits” means the benefits described in Section 4E.4.

(n) “Retirement-Eligible Participant” means an Eligible Participant who:

(1) is at least Age 50 with five (5) or more Vesting Years as of his Qualified Retirement Date; or

(2) satisfies the requirements of paragraph (1) above after taking into account his Enhanced Age and/or his Enhanced Vesting Years.

(o) “Separation Benefits” means the benefits described in Section 4E.5.

(p) “Separation-Eligible Participant” means an Eligible Participant who:

(1) is not a Retirement-Eligible Participant; or

(2) is a Retirement-Eligible Participant who, in accordance with Section 4E.3, elects to receive Separation Benefits.

(q) “Special Payment Period” means, for a Separation-Eligible Participant, the sum of (1) and (2) below:

(1) twelve (12) months; and

(2) one (1) week for each full Vesting Year as of his Qualified Separation Date in excess often (10) but not in excess of thirty-six (36), if any.

(r) “Weekly Base Pay” means:

(1) in the case of an Eligible Participant who was compensated on a salaried basis as of the later of his Employment Date or August 1, 2000, the Eligible Participant’s weekly base salary as of such date, adjusted for any subsequent merit increases (or for a pro rata portion of such merit increases if such increases are based on a greater regularly scheduled workweek than the Eligible Participant’s regularly scheduled workweek as of the later of his Employment Date or August 1, 2000);

(2) in the case of an Eligible Participant who was compensated on a non-salaried basis as of the later of his Employment Date or August 1, 2000, the number of hours per week such Eligible Participant was regularly scheduled to work as of such date multiplied by his regular hourly rate in effect on the day before his Separation from Service, and

(3) in the case of a Disabled Participant, the amount calculated in accordance with (1) or (2) above, whichever applies, determined as of the last day the Participant performed services for the Company immediately prior to the occurrence of his disability.

4E.3 Elections of the Retirement and Separation Benefits. Any Retirement-Eligible Participant shall be entitled to elect to receive Retirement Benefits or Separation Benefits, but not both. A Retirement-Eligible Participant must submit to the Company's Human Resources Department a completed and signed election form, in such form and manner and at such time as may be required by the Administrator.

4E.4 Computation of Retirement Benefits Under the Program.

(a) Each Retirement-Eligible Participant who has not elected Separation Benefits in accordance with Section 4E.3 shall be entitled to early retirement benefits regardless of the number of Vesting Years with which he has been credited. Such early retirement benefits shall be determined under Section 4.3; provided, however, that for purposes of calculating such Retirement-Eligible Participant's Accrued Benefit and determining any applicable reduction in the amount received upon early retirement: (1) such Participant's Age on his Benefit Commencement Date shall be deemed to be his Enhanced Age, (2) such Participant's Benefit Years on his Benefit Commencement Date shall be deemed to be his Enhanced Benefit Years for purposes of Section 3.1(b), (3) such Participant's aggregate Compensation for purposes of Section 3.1(a)(2) shall he deemed to include an additional amount equal to his annual Compensation for the calendar year ending on or immediately preceding his Qualified Retirement Date, and (4) such Participant's early retirement benefits shall be determined using the early retirement reduction factors set forth on Schedule A. The Benefit Commencement Date of a Retirement-Eligible Participant shall not be earlier than the date he attains Age 50, determined without regard to his Enhanced Age.

(b) The Accrued Benefit of a Retirement-Eligible Participant who has not elected Separation Benefits, who satisfies the requirements of an Eligible Participant, other than paragraphs 4E.2(d)(2)(D) and 4E.2(d)(5), and who dies before his Qualified Retirement Date shall be calculated by applying paragraph 4E.4(a) as of the date of his death for purposes of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4E.2(d)(2)(D) and/or 4E.2(d)(5).

(c) Each Retirement-Eligible Participant who has not elected Separation Benefits and who is not employed by the Company under a change in control agreement shall be entitled to receive an Annuity in addition to his Accrued Benefit, which Annuity shall be paid in accordance with Section 4E.6.

4E.5 Computation of Separation Benefits Under the Program

(a) Each Separation-Eligible Participant shall be entitled to pension benefits determined in accordance with the terms of the Plan; provided, however, that for purposes of calculating such Separation-Eligible Participant's Accrued Benefit: (1) such Participant's Age on his Benefit Commencement Date shall be deemed to be his Enhanced Age, (2) such Participant's Benefit Years on his Benefit Commencement Date shall be deemed to be his Enhanced Benefit Years for purposes of Section 3.1(b), and (3) such Participant's aggregate Compensation for purposes of Section 3.1(a)(2) shall be deemed to include an additional amount equal to the product of (i) one-twelfth (1/12) of his annual Compensation for the calendar year ending on or immediately preceding his Qualified Separation Date and (ii) the difference between the number of months included in his Enhanced Benefit Years and the number of months included in his actual Benefit Years (up to a maximum of 480).

For purposes of determining any reduction in the amount received by a Separation-Eligible Participant, if the Separation-Eligible Participant's Enhanced Age as of his Qualified Separation Date is at least 45, he is credited with at least ten (10) Enhanced Vesting Years as of his Qualified Separation Date and his Benefit Commencement Date occurs on or after the date he attains Age 50, determined without regard to his Enhanced Age, such Participant's pension benefits shall be determined using the enhanced vested pension factors set forth on Schedule B.

(b) The Accrued Benefit of a Separation-Eligible Participant who satisfies the requirements of an Eligible Participant, other than paragraphs 4E.2(d)(2)(D) and 4E.2(d)(5), and who dies before his Qualified Separation Date shall be calculated by applying paragraph 4E.5(a) as of the date of his death for purposes of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4E.2(d)(2)(D) and/or 4E.2(d)(5).

(c) Each Separation-Eligible Participant who is not employed by the Company under a change in control agreement shall be entitled to receive an Annuity in addition to his Accrued Benefit, which Annuity shall be paid in accordance with Section 4E.6.

4E.6 Payment and Form of Annuities Under the Program.

(a) Each Eligible Participant described in Sections 4E.4(c) and 4E.5(c) shall receive the sum of (l) the Actuarial Equivalent of his Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) and (2) his Accrued Benefit, with such sum payable at such time, in such form and subject to such adjustments as may otherwise be applicable under Articles IV, IVE and V of the Plan.

In. lieu of receiving such Actuarial Equivalent of his Annuity at such time and in such form as he receives his Accrued Benefits, such Eligible Participant may instead elect to receive immediate payment of his Annuity in accordance with paragraph (b) below or an immediate distribution of his Lump Sum in accordance with paragraph (c) below.

(b) An Eligible Participant may elect) in accordance with the procedure described in Section 4.3, to receive his Annuity immediately, with payment to begin as of his Qualified Retirement Date or his Qualified Separation Date, whichever applies, in the following form:

(1) The Annuity of an Eligible Participant who is unmarried on his Benefit Commencement Date shall be paid in the form of a Single Life Annuity.

(2) The Annuity of an Eligible Participant who is married on his Benefit Commencement Date shall be paid in the form of a Qualified Joint and Survivor Annuity.

(3) In lieu of payment in the form described in (1) above, an Eligible Participant who is unmarried on his Benefit Commencement Date may elect to receive an immediate payment of his Annuity in the form of a contingent annuity, with 50% of the annuity payable upon his death to a contingent beneficiary designated by him. The annuity described in the preceding sentence will be actuarially reduced using the factors described in Appendix A to reflect the payments which may become payable to the beneficiary.

(4) In lieu of payment in the form described in (2) above, an Eligible Participant who is married on his Benefit Commencement Date may elect to receive an immediate payment of his Annuity in the form of a Single Life Annuity.

(c) In lieu of his Annuity, an Eligible Participant may elect to receive an immediate payment of his Lump Sum, with payment to be made as of his Qualified Separation Date or Qualified Retirement Date, whichever applies, in a single sum.

(d) Any election pursuant to paragraph (b)(3),(b)(4) or (c) above by an Eligible Participant shall be made in writing in a manner prescribed by the Company and may be made or revoked at any time within the 90-day period preceding the Benefit Commencement Date but in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a) and, in the case of an Eligible Participant who is married on his Benefit Commencement Date, shall be subject to the spousal consent requirements described in Section 5.7.

(e) In the case of an individual who satisfies the requirements of an Eligible Participant, other than paragraphs 4E.2(d)(2)(D) and 4E.2(d)(5), and who dies before his Qualified Separation Date or Qualified Retirement Date, whichever applies, the Actuarial Equivalent of such Participant's Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) shall be added to his Accrued Benefit for the purpose of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 and 5.4, notwithstanding his failure to satisfy paragraphs 4E.2(d)(2)(D) and/or 4E.2(d)(5).

ARTICLE V. Form of Pensions.

5.1 Unmarried Participants. The monthly annuity of a Participant who is unmarried on his Benefit Commencement Date shall be paid as a Single Life Annuity unless he elects an optional form of benefit under Section 5.3 or receives a lump sum distribution under Section 5.6.

5.2 Married Participants.

(a) The monthly annuity of a Participant who is married on his Benefit Commencement Date, shall be paid as a Qualified Joint and Survivor Annuity, unless he elects an optional form of benefit under Paragraph (b) or Section 5.3 or receives a lump sum distribution under Section 5.6.

(b) A Participant described in Paragraph (a) may elect to waive the Qualified Joint and Survivor Annuity and receive his annuity in the form of a Single Life Annuity. Any such election shall be subject to the spousal consent requirements described in Section 5.7, shall be made in writing in a manner prescribed by the Company and may be made or revoked at any time within the 90 day period preceding the Benefit Commencement Date elected by the Participant but in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a).

5.3 Contingent Annuity Option.

(a) An Active Participant (including a Participant who is treated as an Active Participant for purposes of Section 4.3 and this Section 5.3, but not for any other provision of the Plan) who has at least 14 Benefit Years, or who has attained Age 65 and has at least 5 Benefit Years, or a Participant (including a Participant who continues to be treated as an Active Participant for purposes of Section 4.3 and Section 5.3, but not for any other provision of the Plan) who had a Separation from Service after becoming eligible for early retirement under Section 4.3 (hereinafter referred to as an “Eligible Participant”), may elect, in writing on a form prescribed by the Administrator, a Contingent Annuity Option under which he may designate a percentage of his annuity to be paid upon his death to a contingent beneficiary designated by him. The percentage so designated shall be 25%, 50%, 75% or 100%, as the Participant elects, and may be changed by an Eligible Participant at any time prior to the later of the Participant’s Normal Retirement Date or Separation from Service. The annuity otherwise payable to a Participant electing a Contingent Annuity Option or to his contingent beneficiary will be actuarially reduced using the factors described in Appendix A to reflect the payments which may become payable to the beneficiary. Notwithstanding the above, if the Eligible Participant’s Spouse is designated as contingent beneficiary, the actuarial reduction will not reflect the cost of a joint and survivor annuity option providing a survivor annuity to the Participant’s Spouse of (1) 50% of the amount payable to the Participant, if a 50%, 75% or 100% contingent annuity option is elected, or (2) 25% of the amount payable to the Participant, if a 25% contingent annuity option is elected; provided, however, that the subsidy described in this sentence shall not apply to a former spouse who is to be treated as a Participant's spouse pursuant to a qualified domestic relations order, unless the qualified domestic relations order specifically provides that such subsidy applies to the former spouse. If the contingent beneficiary is other than the Spouse, the percentage payable to the contingent beneficiary after the Participant's death may not exceed the applicable percentage from Appendix B. The Contingent Annuity Option of an electing Participant who has a Separation from Service and is not eligible for early retirement under Section 4.3 shall be canceled.

(b) (1) An Eligible Participant's election or change in election under Paragraph (a) shall become effective on the first of the month next following the date such election or change is properly filed with the Administrator.

(2) An Eligible Participant's election under Paragraph (a) shall not be valid upon a Participant's Benefit Commencement Date if such election is not confirmed in writing by such Participant, with spousal consent as described in Section 5.7, within the 90 day period preceding the Benefit Commencement Date, and in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a). If an Eligible Participant has made no election under Paragraph (a), or has made an invalid election, as of his Benefit Commencement Date, such Participant's pension shall be paid as described in Section 5.1 or 5.2, whichever applies.

(3) (A) The election under Paragraph (a) in effect for an Eligible Participant who is married on the date of his death shall not be valid upon the Participant's death unless (i) the spousal consent requirements of Section 5.7 are satisfied; (ii) if the Participant's death occurs after the first day of the Plan Year in which the Participant attains Age 35, the Participant's election was made or confirmed in writing (with the applicable spousal consent) on or after the first day of such Plan Year, and (iii) in the event that the election in effect under Paragraph (a) does not provide for a survivor benefit to the Participant's surviving Spouse, the Participant has made no change to his election under Paragraph (a) that has not yet taken effect which would result in a survivor benefit payable to his Spouse. If an Eligible Participant who is married at the time of his death has made no election, or has made an invalid election, the Participant's surviving Spouse shall receive the benefit described in Section 5.4. With respect to an Eligible Participant described in the preceding sentence, no additional benefit shall be payable to any other contingent beneficiary or to the Participant's estate.

(B) If an Eligible Participant (1) is unmarried at the time of his death, (2) is survived by one or more children, (3) has not begun receiving any benefits hereunder, and (4) either has failed to make a valid election under Paragraph (A) or is not survived by a designated contingent beneficiary, a benefit equal to the amount that would be payable assuming that the Participant made a valid election under Paragraph (a) and designated a percentage of 100% shall be paid to the Participant's surviving children, if any, in equal shares. For all purposes of the Plan, where applicable, the person to whom benefits are payable pursuant to this Paragraph (b) shall be treated as the Participant's contingent beneficiary.

(c) Except as provided in Paragraph (b):

(1) If an electing Participant who has had a Separation from Service whose Contingent Annuity Option has not been canceled dies on or after the effective date of the option, his contingent beneficiary, if surviving, will receive an annuity for life beginning as of the first day of the second month following his death and based upon the designated percentage of the annuity which the Participant was receiving or to which he would have been entitled; provided, however, that, if the contingent beneficiary is the Participant's surviving Spouse and the designated percentage is at least 50%, payment to the Spouse shall not begin prior to what would have been the Participant's Normal Retirement Date without the Spouse's written consent made within the 90-day period preceding the Benefit Commencement Date.

(2) If an electing Active Participant dies on or after the effective date of the option, his contingent beneficiary, if living, shall receive an annuity, for life, beginning as of the first day of the second month following the month in which the Participant's death occurs, based upon the designated percentage of the benefit to which the Participant would have been immediately entitled if he had retired on the date of his death; provided, however, that, if the contingent beneficiary is the Participant's surviving Spouse, the designated percentage shall be deemed to be 100%, and payment to such Spouse shall not begin prior to what would have been the Participant's Normal Retirement Date without the Spouse's written consent made within the 90-day period preceding the Benefit Commencement Date. For purposes of this Subparagraph only, the annuity to which a Participant would have been entitled shall be his Accrued Benefit reduced in accordance with Section 4.3 and, if applicable, reduced further by 4% per year (to the nearest one-twelfth year) for any period by which his age at the time of his death is less than 50.

(d) (1) If the contingent beneficiary dies after the effective date of the option and after the later of the Participant's Normal Retirement Date or his Separation from Service, the reduced annuity payable to the Participant will remain in effect.

(2) If the contingent beneficiary dies after the effective date of the option, but prior to the later of the Participant's Normal Retirement Date or his Separation from Service, the option shall be canceled upon receipt of proof of death. If the Participant has not then reached his Normal Retirement Date or has not had a Separation from Service, the Participant may elect a subsequent Contingent Annuity Option effective immediately upon notice to the Company, subject to the conditions stated herein. If he has reached his Normal Retirement Date and has had a Separation from Service, the Participant may not make any further elections.

(e) Subject to the conditions of Paragraph (a), an Eligible Participant may make or change his election and designate or change a beneficiary and/or designate a revised benefit percentage at any time prior to the later of the Participant's Normal Retirement Date or Separation from Service. An Eligible Participant may, regardless of whether he has previously made a different election under this Section 5.3, elect in writing to receive his annuity in the form provided in Section 5.1 or 5.2, whichever applies, or in such other form as is permitted under Paragraph (a), subject to the provisions of Section 5.7. The Participant may make such an election at any time before the Benefit Commencement Date but such an election may not be revoked after the Benefit Commencement Date, except as provided in Paragraph (d)(2). Notwithstanding the foregoing, effective July 15, 1990, a Participant who has not reached his Normal Retirement Date and who elects a form of benefit under this Section 5.3 may waive any right to change his election in the future and irrevocably elect a specific Contingent Annuity Option as of his Benefit Commencement Date.

(f) Commencing with payments due September 1, 1986, the minimum monthly annuity to which a designated beneficiary under a Contingent Annuity Option described in this Section 5.3 shall be entitled is $150.

5.4 Death Benefits for Other Vested Participants.

(a) Eligibility. A death benefit shall be payable under this Section 5.4 with respect to a Participant who dies prior to his Benefit Commencement Date if on the date of his death he is married and:

(1) he does not meet the requirements for the Contingent Annuity Option described in Section 5.3, and

(A) he is an Employee who has met the requirements for early or normal retirement under the Plan; or

(B) he is a former Employee who has had a Separation from Service after meeting the requirements of Section 4.3; or

(C) he has been married for at least one year to the same Spouse and has at least five Vesting Years to his credit, or

(2) he does meet the requirements described in Section 5.3 but has made no election, or has made an invalid election, under that Section.

(b) Amount of Benefit. Upon the death of a Participant described in Section 5.4(a), the Participant's surviving Spouse, if living on the date set forth in Subparagraph (1)-(4) of this Section, whichever shall apply, shall receive a pension in accordance with the following rules:

(1) If the Participant is an Employee who has met the requirements for retirement under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant's death occurs or the first day of any month thereafter, shall end with the

payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant had a Separation from Service on the date of his death, had survived and retired on the Benefit Commencement Date elected by the Spouse and had elected an immediate pension in the form of a 100% Contingent Annuity Option; provided, however, that (A) the Spouse's Benefit Commencement Date shall not be later than the later of (i) the Participant's Normal Retirement Date or (ii) the first day of the month following the month in which the Participant's death occurs and (B) the benefit payable to the Spouse of a Participant described in Section 5.4(a)(2) shall be determined without regard to any otherwise applicable actuarial reduction reflecting the cost of the 100% Contingent Annuity Option.

(2) If the Participant is an Employee who has not met the requirements for retirement under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant would have first been eligible to receive his pension under Section 4.4 if he had a Separation from Service on the date of his death and had not died, or the first day of any month thereafter, shall end with the payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant's Separation from Service had occurred on the day of his death and he had survived and elected to begin receiving his pension in the form of a 100% Contingent Annuity Option on the Benefit Commencement Date elected by the Spouse; provided, however, that (A) the Spouse's Benefit Commencement Date shall not be later than what would have been the Participant's Normal Retirement Date and (B) the benefit payable to the Spouse of a Participant described in Section 5.4(a)(2) shall be determined without regard to any otherwise applicable actuarial reduction reflecting the cost of the 100% Contingent Annuity Option.

(3) If the Participant is a former Employee who retired under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant's death occurs or the first day of any month thereafter, shall end with the payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant had elected to begin receiving his pension in the form of a 100% Contingent Annuity Option on the Benefit Commencement Date elected by the Spouse; provided, however, that (A) the Spouse's Benefit Commencement Date shall not be later than the later of (i) the Participant's Normal Retirement Date or (ii) the first day of the month following the month in which the Participant's death occurs and (B) the benefit payable to the Spouse of a Participant described in Section 5.4(a)(2) shall be determined without regard to any otherwise applicable actuarial reduction reflecting the cost of the 100% Contingent Annuity Option.

(4) If the Participant is a former Employee who did not meet the requirements for retirement under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant would have first been eligible to receive his pension under Section 4.4 if he had not died or the first day of any month thereafter, shall end with the payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant elected to begin receiving his actual pension in the form of a 100% Contingent Annuity Option on the Benefit Commencement Date elected by the Spouse; provided, however, that the Spouse's Benefit Commencement Date shall not be later than what would have been the Participant's Normal Retirement Date.

5.5 Notice to Participants.

(a) Each Participant shall receive in written nontechnical language a general description or explanation of (1) the forms of payment described in Sections 5.1, 5.2 and 5.3, including information explaining the relative values of each form of payment, (2) the Participant's right to waive the form of payment described in Section 5.1 or 5.2(a), whichever applies, and elect an optional form of payment and the financial effect of such an election on his pension, (3) the rights of the Participant's Spouse, if any, with respect to the waiver and election, (4) the Participant's right to revoke an election to receive an optional form of payment and the effect of such revocation, (5) if the Participant has not reached his Normal Retirement Date, the Participant's right to defer commencement of his pension until his Normal Retirement Date and the financial effect of such deferment, and (6) a description of the relative value of the optional forms of benefit as compared to the Qualified Joint and Survivor Annuity. Such information shall be furnished to the Participant not less than 30 days and not more than 90 days prior to the Participant's Benefit Commencement Date, and the time for an election under this Section shall begin no earlier than the date such information is furnished.

Notwithstanding the foregoing, effective for Plan Years beginning on or after January 1, 1997, the Participant's Benefit Commencement Date may be fewer than 30 days after the explanation described in this Section is provided if:

(1) the Participant is given notice of his right to a 30-day period in which to consider whether to (i) waive the normal form of benefit and elect an optional form and (ii) to the extent applicable, consent to the distribution;

(2) the Participant affirmatively elects a distribution and a form of benefit and the Spouse, if necessary, consents to the form of the benefit elected;

(3) the Participant is permitted to revoke his affirmative election at any time prior to his Benefit Commencement Date, or if later, the expiration of a 7-day period beginning on the day after the explanation described in this Section is provided to the Participant;

(4) the Benefit Commencement Date is after the date the Administrator receives written notice of the Participant's intent to begin receiving benefits; and

(5) distribution to the Participant does not commence before the expiration of the 7-day period described in paragraph (3) above.

Notwithstanding the foregoing, effective for Plan Years beginning on or after January 1, 2004, the Participant's Benefit Commencement Date may precede the explanation described in this Section, if the Participant so elects, provided that the following conditions are satisfied:

(5) the date the on which the first payment to be received by the Participant is made (the "initial payment date") shall be no earlier than thirty (30) days following the date that the notice is furnished to the Participant, except that the initial payment date may be as early as the seventh day after such notice is provided if (i) such notice clearly indicates that the Participant has a right to a period of thirty (30) days after receiving the notice to consider to waive the basic forms of distribution provided under the Plan and to elect (with spousal consent) an optional form of benefit, (ii) the Participant affirmatively elects a form of distribution with the consent of his Spouse (if required) to commence as of the initial payment date, and (iii) the Participant is permitted to revoke such election until the initial payment date;

(6) the notice shall be provided to the Participant no more than ninety (90) days before the initial payment date, however, the Plan will not fail to satisfy the ninety (90)- day requirement if the delay in providing the distribution is due solely to an administrative delay;

(7) the Participant is not permitted to elect an Benefit Commencement Date that precedes the date upon which the Participant could have otherwise started receiving benefits under the terms of the Plan as in effect on the Benefit Commencement Date;

(8) to the extent that a Participant has not received any payments for the period from the Benefit Commencement Date to the initial payment date, the Participant shall receive a one-time payment to reflect any such missed payments (a "make-up payment"). Such make-up payment shall be adjusted for interest from the period beginning on the Benefit Commencement Date and ending on the initial payment date, which shall be calculated with respect to such payments that would have been received prior to the initial payment date. The interest rate used to compute the adjustment described in the preceding sentence shall equal the 30 Year Treasury rate for December of the preceding Plan Year. Notwithstanding the foregoing, with respect to any Annuity Starting Date on or after January 1, 2008, the interest rate used to compute the adjustment described in the sentence above shall be the interest rate as specified or prescribed by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code, in revenue rulings, notices or other guidance for November of the preceding Plan Year. For purposes of Section 4.6 of the Plan, the limitations set forth

therein shall comply with the adjustments required thereto pursuant to Treasury Regulation 1.417(e)-1 with respect to any Benefit Commencement Date described in this paragraph which is a "retroactive annuity starting date" as defined for purposes of such Regulation; and

(9) if a Participant who is married elects to commence the Participant's benefit as of the initial payment date pursuant to this paragraph, then the Participant's Spouse (including an alternate payee who is treated as the Participant's spouse under a qualified domestic relations order), determined as of the initial payment date, must consent to such election if the survivor benefits payable as of the Benefit Commencement Date are less than the survivor benefits payable under the benefit described in Section 5.2(a) of the Plan as of the initial payment date.

(b) Each Eligible Participant described in Section 5.3(a) shall receive a written explanation of (1) the terms and conditions of the pre-retirement survivor annuity described in Section 5.4, (2) the Participant's right to waive such survivor annuity in favor of the death benefit under a Contingent Annuity Option and the effect of such waiver, (3) the rights of the Participant's Spouse with respect to such waiver, and (4) the Participant's right to revoke such waiver and the effect of such revocation. Such explanation shall be provided when the Participant first becomes an Eligible Participant described in Section 5.3(a) and, if the Eligible Participant has not attained Age 32 at the time of the first notice, again within the three-year period that begins on the first day of the Plan Year in which the Participant attains Age 32.

5.6 Cash-Outs. Effective on such date as shall be determined by the Company, if the Actuarial Equivalent single-sum value, determined as of the date of distribution, of the vested Accrued Benefit of a Participant who has had a Separation from Service, or of the benefit payable to a Spouse or other beneficiary under Section 5.3 or 5.4 by reason of the Participant's death prior to his Benefit Commencement Date, is $5,000 or less, or, for distributions occurring on or after March 28, 2005, $1,000 or less, the benefit shall be paid, as soon as administratively practicable following the later of (a) the Participant's Separation from Service or death, or (b) the effective date of this Section 5.6, as a single-sum in settlement of all liabilities of the Plan in connection with the Participant; provided, however, that no such payment shall be made after such benefit has commenced in any other form.

5.7 Spousal Consent. No Participant's election:

(a) to waive the Qualified Joint and Survivor Annuity in favor of a form of payment other than a Contingent Annuity Option providing for payment of at least 50% of the Participant's annuity to his surviving Spouse, or

(b) to waive the death benefit described in Section 5.4 in favor of the death benefit payable under a form of payment other than a Contingent Annuity Option described in Paragraph (a), above, shall be effective with respect to a Participant who is married unless the Participant's Spouse (as of the Benefit Commencement Date or date of death, whichever applies) consents thereto in writing, and such consent (1) acknowledges the effect of the election, (2) specifies the designated beneficiary or consents to such designation and consents prospectively to any subsequent designation of beneficiary made by the Participant, acknowledging the Spouse's right to limit consent to a specific alternate beneficiary, (3) specifies the optional form of payment or consents to such election and consents prospectively to any subsequent choice of optional form made by the Participant, acknowledging the Spouse's right to limit consent to a specific optional form, and (4) is witnessed by a Plan representative or by a notary public, or the Administrator finds that the Spouse cannot be located.

5.8 Minimum Distribution Requirements. Notwithstanding anything in the Plan to the contrary, the form and timing of all distributions under the Plan to any Participant, including a Participant whose Separation from Service occurred prior to January 1, 1989, shall be in accordance with Section 401(a)(9) of the Code and regulations issued thereunder, including the incidental death benefit requirements of Section 401(a)(9)(G) of the Code and Treas. Reg. §1.401(a)(9)-2.

5.9 Application for Benefits. Except as provided in Section 5.6 or in Section 5.3(c) for a non-Spouse contingent beneficiary, benefit payments shall commence when properly written application for same is received by the Administrator. In the event that a Participant, or the Spouse of a deceased Participant entitled to benefits under the Plan fails to apply to the Administrator by the earlier of (a) the Participant's Normal Retirement Date or the date of the Participant's Separation from service, if later, or (b) the end of the calendar year in which the Participant attains age 70-1/2, the Administrator shall make diligent efforts to locate such Participant or Spouse and obtain such application. In the event the Participant or Spouse fails to make application by the Participant's Required Beginning Date, subject to Section 10.6, the Administrator shall commence distribution as of the Required Beginning Date without such application. No payments shall be made for the period in which benefits would have been payable if the Participant or Spouse had made timely application therefor; provided, however, that, if the Participant's Benefit Commencement Date or, if the Participant has died, his Spouse's Benefit Commencement Date, has been delayed until after the Participant's Normal Retirement Date solely by reason of failure to make application, and not by reason of Suspension Service as described in Section 4.11(b), the benefit payable (i) to the Participant on and after his Benefit Commencement Date, or (ii) to the Participant's Spouse on and after the Spouse's Benefit Commencement Date, shall be equal to the Actuarial Equivalent of the benefit the Participant or the Spouse would have received had benefits commenced on the Participant's Normal Retirement Date, as determined to reflect the deferral of benefit commencement.

5.10 Direct Rollovers. In the event any payment or payments under the Plan to be made to a "eligible distributee" would constitute an "eligible rollover distribution," such eligible distributee may request that, in lieu of payment to the eligible distributee, all or part of such payment or payments be rolled over directly from the Trustee to the trustee of an "eligible retirement plan." Any such request shall be made at the time and in the manner prescribed by the Administrator or its delegate, subject to such requirements and restrictions as may be prescribed by applicable Treasury regulations. For purposes of this Section 5.10:

(a) "eligible distributee" shall include the Participant, his Spouse or his alternate payee under a qualified domestic relations order within the meaning of Section 414(p) of the Code or, effective January 1, 2008, the Participant's beneficiary who is not the Participant's Spouse;

(b) "eligible rollover distribution" shall mean a distribution from the Plan, excluding (i) any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) over the life (or life expectancy) of the eligible distributee, the joint lives (or joint life expectancies) of the eligible distributee and eligible distributee's designated beneficiary, or a specified period of ten (10) or more years, and (ii) any distribution to the extent such distribution is required under Section 401(a)(9) of the Code; and

(c) "eligible retirement plan" shall mean (i) an individual retirement account described in Section 408(a) of the Code, (ii) an individual retirement annuity described in Section 408(b) of the Code, (iii) an annuity plan described in Section 403(a) of the Code, (iv) a qualified plan the terms of which permit the acceptance of rollover distributions, (v) an eligible deferred compensation plan described in Section 457(b) of the Code that is maintained by an eligible employer described in Section 457(e)(i)(A) of the Code that shall separately account for the distribution, (vi) an annuity contract described in Section 403(b) of the Code or (vii) an individual retirement plan described in Section 408A(b) of the Code; provided, however, that (x) with respect to a plan described in clause (vii), for transfers occurring before January 1, 2010, the eligible distributee meets the requirements of Section 408A(c)(3)(B) of the Code and (y) with respect to a distribution (or portion of a distribution) to a person who is not the Participant or the surviving Spouse of the Participant, "eligible retirement plan" shall mean only a plan described in clause (i) or (ii) or, effective January 1, 2010, clause (vii), that, in either case, is established for the purpose of receiving such distribution on behalf of such person.

5.11. Special Lump Sum Payment Option. (a) Eligibility. A Participant (but not his or her Beneficiary) may elect to receive, during the election period described in Paragraph (b), his or her deferred Accrued Benefit ("Deferred Annuity") under Section 4.4 of the Plan in the form of a lump sum payment ("Special Lump Sum Payment") or, an "Immediately Commencing Annuity" (as defined below); provided, however, that:

(i) the Participant has a termination of employment on or prior to June 30, 2012 and does not die and is not rehired during the period beginning July 1, 2012 and ending on the date payment is made or commences in accordance with this Section 5.11;

(ii) such termination of employment is not on account of the Participant's disability, following which the Participant is receiving long-term disability payments under any long-term disability program of an Employer, including on June 30, 2012;

(iii) the Participant's Deferred Annuity is not subject to a qualified domestic relations order as defined in Section 414(p) of the Code;

(iv) the Participant is not immediately, as of his or her termination of employment, eligible for early retirement benefits in accordance with this Article IV;

(v) the Participant is not on a leave of absence or layoff from an Employer on June 30, 2012;

(vi) the Participant is not 70 ½ years of age or older as of October 1, 2012; and

(vii) the Participant can be located, after a diligent search, as necessary, by the Plan Administrator before July 1, 2012.

For each such Participant described in this Paragraph (a), the term "Immediately Commencing Annuity" shall mean, as applicable, either:

(i) with respect to a Participant eligible to commence receipt of his or her Deferred Annuity as of December 1, 2012, in accordance with the requirements of Section 4.4, any applicable optional form of annuity described in Article V; or

(ii) with respect to any other Participant, a single life annuity, 50% "qualified joint and survivor annuity" (within the meaning Section 417(b) of the Code) or a 75% "qualified optional survivor annuity" (within the meaning Section 417(g) of the Code).

(b) Election and Election Period. To receive the distribution of benefits described in Paragraph (a), an eligible Participant must voluntarily elect to receive a distribution pursuant to this Section 5.11 by completing an election form and spousal waiver, if required, provided by the Administrator, and submitting such forms to the Administrator after October 1, 2012 and before the following dates, as applicable,

(i) November 15, 2012, with respect to a Participant who elects a Special Lump Sum Payment; and

(iii) December 15, 2012, with respect to a Participant who elects an Immediately Commencing Annuity,

or such other period during 2012 determined by the Administrator.

The Administrator shall provide each eligible Participant, not less than 30 days and not more than 180 days before the Benefit Commencement Date, an application form including a general description of the material features, as well as an explanation of the relative values and financial effect, of the optional forms of benefit available under this Section 5.11, in a manner that satisfies the notice requirements of Section 417(a)(3) of the Code and the regulations thereunder. The form shall indicate the Participant's right to waive a survivor annuity, his or her surviving Spouse's right to consent to such waiver or refuse such consent, and the right to revoke any waiver, within the 180 day period preceding the Benefit Commencement Date, and shall include a description of the right of the Participant, if any, to defer receipt of a distribution and the consequences of failure to defer such receipt, in accordance with Treasury guidance under Section 411(a)(11) of the Code.

(c) Amount of Payment. The Special Lump Sum Payment shall equal the actuarial equivalent of the Participant's nonforfeitable Deferred Annuity, based on the following factors:

(i) the applicable interest rate described in Section 417(e)(3) of the Code for August of 2011;

(ii) an assumed commencement date of the later of (A) age 65, and (B) the Participant's age as of December 1, 2012; and

(iii) the applicable mortality table, as defined in Section 417 of the Code and the regulations promulgated thereunder.

The Immediately Commencing Annuity shall be calculated:

(i) in accordance with the applicable terms of the Plan, for a Participant who is eligible to immediately commence benefits under the terms of the Plan as of the payment date set forth in Paragraph (d); and

(ii) as the actuarial equivalent of the Special Lump Sum Payment, for each other Participant.

(d) Payment of Benefit. If an eligible Participant elects the distribution of his or her Deferred Annuity in accordance with this Section 5.11, payment shall be made, or commence to be made, on or before December 1, 2012, or as soon as administratively practicable thereafter.

(e) Death and Rehire. If an eligible Participant elects the distribution of his or her Deferred Annuity in accordance with this Section 5.11 and subsequently dies or is rehired as an Employee before distributions commence, his or her election shall be null and void and the Participant's benefit shall be paid pursuant to the Plan without regard to this Section 5.11. Notwithstanding anything contained herein to the contrary, upon distribution of a Special Lump Sum Payment or an Immediately Commencing Annuity made to an individual in accordance with this Section 5.11, in the event of the individual's rehire with an Employer following the date such distribution is made, the individual shall not be eligible to participate in the Plan during such period of rehire and may be eligible to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees (or such other plan that applies to employees of an Employer hired on or after December 1, 2012), as applicable, in accordance with their terms and conditions.

ARTICLE VI. Breaks in Service.

6.1 Whenever used in this Article:

(a) "One-Year Break in Service" means a calendar year in which an Employee completes 500 or fewer Hours of Service.

(b) "Reemployment Date" means the first day on which an Employee who has had a Separation from Service completes an Hour of Service in a calendar year that is not a One-Year Break in Service.

(c) "Reemployment Eligibility Computation Period" means an Eligibility Computation Period determined as if the Employee's Employment Date were his Reemployment Date.

6.2 If an Employee has a Separation from Service before he has met the requirements for retirement under Sections 4.1-4.3 or for a deferred annuity under Section 4.4, he shall be deemed to have received a distribution of his entire nonforfeitable Accrued Benefit of zero dollars upon such Separation from Service and his Eligibility Years, Accrued Benefit, Benefit Years, and Vesting Years shall be canceled.

6.3 If an Employee completes at least 1000 Hours of Service in a Reemployment Eligibility Computation Period he shall be credited with an Eligibility Year.

6.4 (a) The Eligibility Years of an Employee whose Eligibility Years have been canceled shall be restored if:

(1) he is credited with an Eligibility Year with respect to a Reemployment Eligibility Computation Period that begins on or after his Reemployment Date; and

(2) he again becomes an Employee at a time when the number of consecutive One-Year Breaks in Service he has incurred is less than the greater of five or the number of Eligibility Years the Employee had to his credit on account of his employment prior to the first One-Year Break in Service.

(b) If a former Employee whose Eligibility Years were not canceled under Section 6.2 or are restored under this Section becomes an Eligible Employee, he shall become an Active Participant as of the later of the day he so becomes an Eligible Employee or the day he would have become an Active Participant under Article II if he had been an Eligible Employee at all times since his prior Separation from Service. If a former Employee whose Eligibility Years were canceled under Section 6.2 and are not restored under this Section becomes an Eligible Employee, he shall become an Active Participant as provided in Article II, except that his Reemployment Date shall be treated as his Employment Date.

6.5 The Benefit Years and Accrued Benefit of an Employee whose Benefit Years have been canceled shall be restored upon his reemployment if his Eligibility Years are restored under Section 6.4. If a Participant's Benefit Years and Accrued Benefit were not canceled pursuant to Section 6.2 upon his prior Separation from Service, his Benefit Years earned prior to his Separation from Service shall be aggregated with his Benefit Years earned after his Reemployment Date for purposes of determining the Participant's Accrued Benefit; provided, however, that:

(a) if the Participant previously received a single-sum distribution under Section 5.6 on or before the close of the second Plan Year following the Plan Year in which the Participant's Separation from Service occurred, the Participant's Benefit Years earned prior to his Separation from Service shall be disregarded upon his reemployment; or

(b) if the Participant received a single-sum distribution under Section 5.6 on a date later than that described in Paragraph (a), the Participant's Accrued Benefit determined on and after his reemployment shall be reduced by the Actuarial Equivalent of the distribution received by the Participant under Section 5.6 upon his prior Separation from Service.

6.6 The Vesting Years of an Employee whose Vesting Years have been canceled shall be restored if:

(a) he is credited with a Vesting Year after his Reemployment Date; and

(b) he again becomes an Employee at a time when the number of consecutive One-Year Breaks in Service he has incurred is less than the greater of five or the number of Vesting Years the Employee had to his credit on account of his employment prior to the first One-Year Break in Service.

6.7 Notwithstanding any provision in the Plan to the contrary, effective January 1, 1996, an Employee who was transferred to COPCO and whose benefits were transferred from the Plan in connection with the sale of COPCO shall receive, upon such Employee's Reemployment Date, credit for years of service with the Company prior to such transfer for purposes of calculating Eligibility Years and Vesting Years (but not Benefit Years).

ARTICLE VII. Contributions.

7.1 Contributions by the Company. The Company shall contribute each year an amount actuarially determined to be sufficient to provide the benefits under the Plan. All Company contributions to the Plan are conditioned upon their deductibility for Federal income tax purposes. The Company reserves the right, however, to reduce, suspend or discontinue its contributions under the Plan for any reason at any time. Except as provided in this Section or Section 9.2, it shall be impossible for any part of the Company's contributions to revert to the Company, or to be used for, or diverted to, any purpose other than for the exclusive benefit of Participants, annuitants and their beneficiaries. In the case of a contribution (a) made by the Company as a mistake of fact, or (b) for which a tax deduction is disallowed, in whole or in part, by the Internal Revenue Service, the Company shall receive a refund of said contribution within one year after payment of a contribution as a mistake of fact, or within one year after disallowance of a tax deduction, to the extent of such disallowance, as the case may be.

7.2 Source of Benefits. All benefits under the Plan shall be paid exclusively from the Fund, and the Company shall have no duty to contribute thereto except as provided in this Article.

ARTICLE VIII. Administration.

8.1 The Administrator. (a) In General. The Company acting through its Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Retirees, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan. The determination of the Administrator with respect to an Employee's years of Credited Service, the amount of the Employee's Earnings, Highest Average Annual Pay, Federal Benefit and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 6 (relating to Service Annuity forms). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Retirees, the amounts of all Service Annuities, the dates of death of Retirees and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Service Annuities to be paid out of the Trust.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator. The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

8.2 The Investment Office. The Investment Office shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Section 404(a)(2) of ERISA and all other applicable limitations. In addition to the duties, responsibilities and rights of the Investment Office set forth in Article 8, the Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Office.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

8.3 The Corporate Investment Committee. The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Office and shall review annual manager review results and any other reports and documents submitted by the Investment Office.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Office, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Office.

(iii) The Corporate Investment Committee and the Company’s Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

8.4 Status of Administrator, the Investment Office and the Corporate Investment Committee. The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his rights under this Plan.

8.5 Notice to Trustee of Members. The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

8.6 Allocation of Responsibilities. Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

8.7 General Governance. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

8.8 Indemnification. The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

8.9 No Compensation. None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

8.10 Employ of Counsel and Agents. The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

8.11 Claims Procedures. Any Participant or distributee who believes he is entitled to benefits in an amount greater than those which he is receiving or has received may file a claim with the Administrator (or its delegate). Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator (or its delegate) shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable regulations. If it is determined that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which it is expected that the benefit determination will be rendered. The notice of the decision with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The notice shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Administrator (or its delegate) of the adverse benefit determination by filing, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the Administrator (or its delegate) within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the final decision. If it is determined that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the determination on review is expected to be rendered. The review shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

8.12 Actuary to Be Employed. The Company or the Investment Office shall engage an actuary to do such technical and advisory work as the Company or the Investment Office may request, including analyses of the experience of this Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Office of an annual actuarial report, which report shall contain information showing the financial condition of this Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Office.

8.13 Funding Policy. The board of directors of the Company shall establish a funding policy and method consistent with the objectives of this Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Office.

8.14 Notices to Participants, Etc. All notices, reports and statements given, made, delivered or transmitted to a Participant or any other person entitled to or claiming benefits under this Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or such other person at the address last appearing on the records of the Administrator.

8.15 Notices to Employers or Administrator. Written directions, notices and other communications from Participants or any other person entitled to or claiming benefits under this Plan to the Employers or Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the forms prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

8.16 Records. Each of the Administrator, the Investment Office and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

8.17 Responsibility to Advise Administrator of Current Address. Each person entitled to receive a payment under this Plan shall file with the Administrator in writing such person's complete mailing address and each change therein. A check or communication mailed to any person at such person's address on file with the Administrator shall be deemed to have been received by such person for all purposes of this Plan. Although neither the Administrator nor the Trustee shall be obliged to search for or ascertain the location of any person, the Administrator shall make reasonable efforts to locate any missing Participant or Beneficiary entitled to benefits hereunder. If the Administrator is in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his last address known to the Administrator, notify such person that all future payments will be withheld until such person submits to the Administrator evidence of his continued life and proper mailing address.

8.18 Electronic Media. Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

8.19 Correction of Error. If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

8.20 Applicable Law. Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

8.21 Statute of Limitations for Actions under the Plan. Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources

Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

8.22 Forum for Legal Actions under the Plan. Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

8.23 Legal Fees. Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Corporate Investment Committee, any Plan fiduciary, the Chief Human Resources Officer, any Plan administrator, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE IX. Amendment and Termination.

9.1 Amendment. Exelon Corporation may amend the Plan at any time for any reason. Each amendment to the Plan shall be adopted by Exelon Corporation's Board of Directors (or a committee thereof); provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility. If an amendment changes the vesting provisions of the Plan, any person who is a Participant on the later of the date the amendment is adopted or becomes effective shall have at all times a vested interest in his Accrued Benefit as of that date determined without regard to the amendment. In addition, within a reasonable period determined by the Exelon Corporation in accordance with regulations issued by the Secretary of the Treasury, any Participant who has at least three Vesting Years to his credit on the last day of the election period may elect to have his vested interest in his entire Accrued Benefit determined without regard to the amendment. Except as otherwise permitted by law, no amendment shall reduce a Participant's Accrued Benefit nor result in the elimination or reduction of a benefit "protected" under Section 411(d)(6) of the Code.

9.2 Termination. Exelon Corporation may terminate or partially terminate the Plan through resolutions adopted by Exelon Corporation's Board of Directors. If the Plan is terminated or partially terminated, the assets of the Plan shall be allocated, subject to Section 9.3, as provided in Section 4044 of the Employee Retirement Income Security Act of 1974 (as it may be from time to time amended or construed by any appropriate governmental agency or corporation), without subclasses. Any amount remaining after all fixed and contingent liabilities of the Plan have been satisfied shall be returned to Exelon Corporation. Allocations under this Section shall be nonforfeitable. Except as otherwise required by law, the time and manner of distribution of the assets shall be determined by Exelon Corporation by amendment to the Plan pursuant to Section 9.1.

9.3 Limitation on Benefits. The following provisions shall be effective with respect to distributions made on or after May 14, 1990; distributions made prior to May 14, 1990 shall be subject to the restrictions described in Treas. Reg. §1.401-4(c).

(a) In the event of Plan termination, the benefit payable to any Highly Compensated Employee shall be limited to a benefit that is nondiscriminatory under Section 401(a)(4) of the Code. If payment of benefits is restricted in accordance with this Paragraph (a), assets in excess of the amount required to provided such restricted benefits shall become a part of the assets available under Section 9.2 for allocation among Participants and beneficiaries of Participants whose benefits are not restricted under this Paragraph (a).

(b) The restrictions of this Paragraph (b) shall apply prior to termination of the Plan to any Participant who is a Highly Compensated Employee and who is one of the 25 highest paid employees or former employees of the Company and all Affiliates for any Plan Year. The annual payments made from the Plan on behalf of any such Participant shall be limited to an amount equal to (1) the payments that would have been made under a single life annuity that is the Actuarial Equivalent of the sum of the Participant's Accrued Benefit and any other benefits under the Plan (other than a social security supplement) and (2) the payments that the Participant is entitled to receive under a social security supplement.

(c) The restrictions in Paragraph (b) shall not apply:

(1) if, after the payment of benefits to or on behalf of such Participant, the value of the Plan assets equals or exceeds 110 percent of the value of the current liabilities (within the meaning of Section 412(l)(7) of the Code);

(2) if the value of the benefits payable to or on behalf of the Participant is less than one percent (1%) of the value of current liabilities before distribution; or

(3) if the value of the benefits payable to or on behalf of the Participant does not exceed $5,000.

ARTICLE X. Miscellaneous.

10.1 Forfeitures. All forfeitures arising under the Plan shall be used as soon as possible to reduce the Company's contributions and shall not be applied to increase the benefits any person would otherwise receive under the Plan.

10.2 Mergers, Etc. No merger or consolidation with, or transfer of any of the Plan's assets or liabilities to, any other plan shall occur at any time unless each Participant and annuitant would (if the Plan had then terminated) receive a benefit immediately after the merger, consolidation, or transfer which is equal to or greater than the benefit he would have been entitled to receive immediately before the merger, consolidation, or transfer (if the Plan had then terminated).

10.3 Nonalienation of Benefits. Except (a) to the extent permitted by the Employee Retirement Income Security Act of 1974, (b) pursuant to a qualified domestic relations order, (c) to the extent required to satisfy a Federal tax levy made pursuant to Section 6331 of the Code, or (d) effective as of January 1, 1997, pursuant to Section 401(a)(13) of the Code, to the extent a judgment relates to the Participant's conviction of a crime involving the Plan, or a judgment, order, decree or settlement agreement between the Participant and the Secretary of Labor or the Pension Benefit Guaranty Corporation relates to a violation of part 4 of subtitle B of title I of ERISA, no benefit under this Plan may be voluntarily or involuntarily assigned or alienated. Notwithstanding the above, a Participant may authorize the Administrator to deduct from benefit payments under the Plan up to 10% of each such payment as contributions to a Company political action committee. Any such authorization shall be revocable by the Participant at any time.

10.4 Effect on Employment. This Plan shall not confer upon any person any right to be continued in the employment of the Company.

10.5 Facility of Payment. If the Company deems any person incapable of receiving benefits to which he is entitled by reason of minority, illness, infirmity, or other incapacity, it may direct that payment be made directly for the benefit of such person or to any person selected by the Company to disburse it, whose receipt shall be a complete acquittance therefor. Such payments shall, to the extent thereof, discharge all liability of the Company and the party making the payment.

10.6 Lost Payees. If a Participant, Spouse or other beneficiary to whom a benefit is payable under the Plan cannot be located following a reasonable effort to do so by the Administrator, such benefit shall be forfeited. Whether or not efforts to locate a Participant have previously been made, the Administrator shall make reasonable efforts to locate the Participant (or the Spouse of a deceased Participant) during the one-year period preceding the Participant's Required Beginning Date. If such efforts fail to locate the Participant or Spouse, such Participant or Spouse shall be presumed dead as of the Required Beginning Date and any benefit payable to the Participant or Spouse shall be forfeited. In any case, if a claim for a forfeited benefit is subsequently filed by the Participant, Spouse or beneficiary, such benefit shall be reinstated and paid in accordance with the appropriate provisions of the Plan.

10.7 Effective Date. The provisions of this instrument apply only to individuals who complete an Hour of Service on or after the effective date stated under the title of the Plan on page one. The eligibility and benefits of any other person shall be determined under the Plan as in effect when he last separated from service except as expressly provided with respect to him by amendment adopted thereafter; and except that the provisions of Section 2.10 (relating to rehire of Employees), Section 2.11 (relating to change in employment status or transfer to affiliate), Section 4.6 (relating to maximum annuity), Section 4.12 (relating to benefit restrictions as a result of funding), Article VIII (relating to administration), Article IX (relating to amendment and termination of the Plan), and this Article X (relating to miscellaneous provisions) shall be effective for all such persons.

10.8 Expenses. The expenses of the Trustee in the administration of the Trust, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Trust, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan and the Trust, including, but not limited to, “direct expenses” incurred in administering the Plan and the Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Trust shall be paid by the Trustee from the Trust in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Any such expenses that are borne by the Employers shall be paid out of their own funds in such proportions as the Administrator shall determine. In the event that the Company or any other Employer advances money on behalf of the Trust for the payment of any expenses incurred in the operation of the Plan, the Trustee shall reimburse the Company or such other Employer from the Trust for any amount so advanced, without interest or fees.

ARTICLE XI. Top-Heavy Provisions.

11.1 Definitions. Whenever used in this Article:

“Determination Date” means, with respect to any Plan Year, the last day of the preceding Plan Year.

“Key Employee” means any Participant who, at any time during the Plan Year or any of the four preceding Plan Years, is an individual described in Section 416(i) of the Code and the regulations thereunder.

“Permissive Aggregation Group” means a group of qualified retirement plans maintained by the Company or any Affiliate, which group consists of the Required Aggregation group and any other plan or plans which, considered together with the Required Aggregation Group, meet the requirements of Sections 401(a)(4) and 410 of the Code.

“Required Aggregation Group” means the group of qualified retirement plans maintained by the Company or an Affiliate, including a frozen plan or a plan that has been terminated during the five-year period ending on the Determination Date, which group consists of this Plan, each other plan in which a Key Employee is a participant (or, in the case of a terminated plan was a participant in such five-year period) and each other plan that enables any such plan to meet the requirements of Section 401(a)(4) or 410 of the Code, but only if such group includes this Plan. Otherwise, the Required Aggregation Group consists of this Plan only.

“Top-Heavy Plan Year” means a Plan Year that begins after December 31, 1983, in which the Plan is top-heavy. The Plan is top-heavy for a given Plan Year if for that Plan Year (1) the Required Aggregation Group is top-heavy, and (2) the Required Aggregation Group is not part of a Permissive Aggregation Group that is not top-heavy. The Required Aggregation Group or a Permissive Aggregation Group (the “Group”) is top-heavy for a given Plan Year if the present value of the cumulative accrued benefits (or, the aggregate of the accounts, in the case of a defined contribution plan included in such Group) of participants who are Key Employees exceeds 60% of the like amount determined for all participants in all plans included in such Group. For purposes of this definition:

(a) the present value of the accrued benefit or the account of any participant shall be increased by the amount of all plan distributions to such participant during the five year period ending on the Determination Date; provided that no such increase shall arise from any rollover contribution or plan-to-plan transfer from this Plan that is not initiated by the participant or is made to another plan maintained by the Company or an Affiliate;

(b) the present value of the accrued benefit or the account of a participant who has been a Key Employee but no longer is a Key Employee shall not be taken into account;

(c) the present value of the accrued benefit or the account of any Participant who has not performed services for the Company or an Affiliate at any time during the five-year period that ends on the Determination Date shall not be taken into account;

(d) any rollover contribution or plan-to-plan transfer to this Plan that is initiated by a participant and made from a plan that is not maintained by the Company or an Affiliate after December 31, 1983 shall not be taken into account;

(e) the five year period referenced above shall be changed to a one year period for all distributions made on account of a severance from employment, death, or disability; and

(f) the present value of accrued benefits shall be determined, effective January 1, 1987, under the method used for accrual purposes for all plans maintained by the Company and all Affiliates if a single method is used by all such plans, or, otherwise, the slowest accrual method permitted under Section 411(b)(1)(C) of the Code.

11.2 Top-Heavy Operating Rules. Anything in the Plan to the contrary notwithstanding, the following rules shall apply in a Top-Heavy Plan Year:

(a) For purposes of determining benefits under this Article XI, “compensation” shall mean compensation as reported on Forms W-2 by the Company or any Affiliate for such Plan Year and the maximum amount of compensation of any Participant who is an Employee during such Plan Year shall be $150,000, or such other amount as may apply to such Participant pursuant to Section 401(a)(17) of the Code and regulations issued thereunder.

(b) For purposes of determining the maximum annuity in Section 4.6 for Plan years beginning before January 1, 2000, “1.0” shall be substituted for “1.25”, wherever it appears.

(c) The Accrued Benefit which each Participant who is an Employee but not a Key Employee under this Plan derives from contributions by the Company shall be increased by the amount necessary to cause the Accrued Benefits payable to each Participant in such year, when expressed as a benefit payable annually in the form of a Single Life Annuity, to equal at least the required minimum benefit, where the required minimum benefit is the product of:

(1) the average of the Participant’s compensation for the five consecutive Plan Years that yield the highest average, disregarding Plan Years which begin before January 1, 1984, and Plan Years which are not Top-Heavy Plan Years, and

(2) the lesser of:

(A) 2 percent multiplied by the number of Vesting Years with the Company which were also Top-Heavy Plan Years and which were completed after January 1, 1984; or

(B) 20 percent.

For purposes of determining whether an increase in benefit accrual is required, all plans included in the Required Aggregation Group shall be treated as one plan.

(d) Anything in the Plan to the contrary notwithstanding, in any Top-Heavy Plan Year, a Participant who does not otherwise have a nonforfeitable right to 100% of his Accrued Benefit shall have a nonforfeitable right to a percentage of his Accrued Benefit in accordance with the following schedule:

Vesting Years	Nonforfeitable Percentage
2	20
3	40
4	60
5	100

In any Plan Year following the last Top-Heavy Plan Year, any Employee who is a Participant on the last day of the last Top-Heavy Plan Year shall have at all times a vested interest in his Accrued Benefit as of that date determined under the schedule set forth above. In addition, within a reasonable period determined by the Company, any Participant who has at least three Vesting Years to his credit on that date may elect to have his vested interest in his entire Accrued Benefit determined under the schedule set forth above.

ARTICLE XII. Post Retirement Health Benefits.

12.1 Eligibility

(a) Effective December 1, 1994, post-retirement health befits may be paid under this Article, to the extent the Company elects to fund benefits under this Article, to any Participant, who is receiving or has received pension benefits under this Plan, and if applicable, to the Spouse or dependents of such Participant; provided, however, that the Company may, in its discretion, decide not to provide post-retirement health benefits under this Article for Key Employees (as defined in Section 11.1) and, if applicable, their Spouses and dependents.

(b) In addition to satisfying the requirements of Subsection (a), any person claiming post-retirement health benefits under this Plan must meet all applicable requirements imposed in the post-retirement health plans maintained by the Company. All determinations of benefit levels and eligibility for benefits shall be made pursuant to the terms of such post-retirement health plans.

(c) The establishment of an account under this Article XII to provide payment for post-retirement health benefits shall not obligate the Company to maintain its post-retirement health plans, and the Company shall retain the same ability to amend or terminate such post-retirement health plans as if this Article XII did not exist.

Notwithstanding the foregoing, post-retirement health benefits shall not be available for any Power Team Employee.

12.2 Benefits Provided.

(a) Benefits under this Article shall include all health benefits provided by the post-retirement health plans maintained by the Company, including payment of Medicare Part B premiums to the extent provided by such post-retirement health plans, to the extent such benefits are not otherwise provided by the Company.

(b) Benefits under this Article shall be provided using any method or combination of methods as the Company shall deem appropriate, including, but not limited to , purchase of insurance and the payment of premiums for such insurance, direct reimbursement of costs incurred by the provider of such benefits or reimbursement to the individual to whom such benefits were provided.

(c) Benefits and coverage under this Article shall not be discriminatory in favor of officers, shareholders, supervisory employees or highly compensated employees.

12.3 Establishment of Accounts.

(a) A separate account shall be maintained with respect to the contributions to fund benefits under this Article. This account is to be maintained for accounting purposes only. Funds accounted for in such account may be invested on a commingled basis with pension benefit contributions under this Plan without identification of which investments are allocable to each account, provided that earnings on all Plan assets are allocated in a reasonable manner.

(b) If the Company elects to fund post-retirement health benefits for Key Employees under this Article, as separate account shall be maintained for post-retirement health benefits payable to each Key Employee, his Spouse and dependents. Benefits under this Article shall be payable to such Key Employee, Spouse and dependents only from such account. The separate account maintained under this Subsection (b) shall be a true separate account, and not maintained merely for accounting purposes. Commingling of assets held in such account with any other Plan assets is not permitted. For purposes of Section 415 of the Code contributions allocated to any separate account under this Subsection (b) shall be treated as an annual addition to a defined contribution plan.

12.4 Funding.

(a) Contributions to provide benefits under this Article may be contributory or non-contributory, in accordance with the terms of the post-retirement health plans maintained by the Company.

(b) Amounts contributed to fund post-retirement health benefits shall be reasonable and ascertainable. The total amount contributed to fund post-retirement health benefits under this Article shall not exceed the cost of providing such benefits. The total cost of providing such benefits shall be determined in accordance with a generally accepted actuarial method selected by the Company which is reasonable in view of the provisions and coverage of the Plan, the funding medium and other relevant considerations, including, but not limited to, applicable Treasury regulations. For purposes of determining the cost of providing post-retirement health benefits, the actuarial method may take into account reasonable projected increases in the cost of providing health benefits. Forfeitures, if any, under this Article shall be applied as soon as possible to reduce employer contributions to fund benefits under this Article.

(c) Post-retirement health benefits provided under this Article, when added to life insurance protection provided under the Plan, shall be incidental and subordinate to pension benefits provided under the Plan. For purposes of this Article, post-retirement health benefits shall be considered incidental and subordinate if the aggregate of the contributions for post-retirement health benefits provided under this Article plus the contributions for life insurance protection under this Plan does not exceed 25 percent of the total contributions to the Plan (other than for past service credit) made on or after December 1, 1994.

(d) Until the satisfaction of all liabilities to be provided under this Article, neither amounts contributed to fund post-retirement health benefits under this Article nor earnings thereon shall be used for or diverted to any purpose other than providing such benefits or payment of necessary or appropriate expenses attributable to the administration of post-retirement health accounts under this Article. Any amounts contributed to fund medical benefits under this Article remaining in a post-retirement health account after the satisfaction of all liabilities arising under this Article must be returned to the Company.

(e) Nothing in this Article shall obligate the Company to pay benefits described in Section 12.2 to the extent those benefits exceed assets contributed to the Fund to provide post-retirement health benefits under this Article. Furthermore, nothing in this Article shall imply that amounts contributed to the Fund to provide pension or other benefits (other than post-retirement health benefits) available under the Plan will be used to provide post-retirement health benefits under this Article. The Company may, in its discretion, fund all or any part of the benefits described in Section 12.2 from other sources or may pay such benefits out of its general assets as the benefits become payable.

(f) If in any proceeding subsequent to December 1, 1994, under Section 1308 of the Pennsylvania Public Utility Code, the Company is not permitted to fully recover in rates the contributions made to the separate account maintained to fund benefits under this Article, the Company, at its discretion, may elect to defer or discontinue funding the benefits under this Article.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officer on this ____ day of December, 2012.

EXELON CORPORATION

By ______________________________

Sr. Vice President &
Chief Human Resources Officer

ATTEST:

____

Title ______________________________

SERVICE ANNUITY PLAN

APPENDIX A

Actuarial equivalence under this Plan shall mean a benefit of equivalent value when computed using a 7% interest rate and the mortality tables attached to the Plan as Exhibit A (for pensioners) and B (for beneficiaries, if applicable), with such exceptions as specifically set forth in the Plan.

For distributions on and after December 1, 2012, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 only shall be determined using (i) the interest rate used shall be the interest rate as defined in Section 417(e)(3)(C) of the Code for the fifth month (or, if more favorable to the recipient of a lump sum payment between December 1, 2012 and December 1, 2013), the second month) preceding the calendar year in which such distribution is made or commences and (ii) the mortality table shall be the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Benefit Commencement Date occurs. For distributions on or after January 1, 2008 and on or before November 30, 2012, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 shall be determined by using (i) the interest rate as defined in Section 417(e)(3)(C) of the Code for the second month preceding the calendar year in which such distribution is made or commences and (ii) the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Benefit Commencement Date occurs.

For distributions on or after January 1, 2000 and on or before December 31, 2007, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 shall be determined using the annual rate of interest on 30-year Treasury securities as specified by the Commissioner of the Internal Revenue Service pursuant to Section 417(e)(3)(A) of the Code and regulations issued thereunder for the second full calendar month preceding the first day of the Plan Year containing the date of distribution, and the mortality table shall be the mortality table prescribed by the Commissioner of Internal Revenue Service pursuant to Section 417(e)(3)(A) of the Code on the date as of which the single sum payment is being determined, if the use of such assumptions would result in a greater benefit.

For the period beginning on or after January 1, 2000, and ending on or before December 31, 2001, and ending on the date of adoption of this amendment and restatement, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 shall be determined on the basis of the assumptions which would be used as of the first day of the Plan Year containing the date of distribution by the Pension Benefit Guaranty Corporation for purposes of determining the present value of a lump sum distribution upon plan termination, if the use of such assumptions would result in a greater benefit.

APPENDIX B

MINIMUM DISTRIBUTION INCIDENTAL BENEFIT TABLE

Excess if Age of Participant over Age of Beneficiary	Applicable Percentage
10 years or less	100%
11	96%
12	93%
13	90%
14	87%
15	84%
16	82%
17	79%
18	77%
19	75%
20	73%
21	72%
22	70%
23	68%
24	67%
25	66%
26	64%
27	63%
28	62%
29	61%
30	60%
31	59%
32	59%
33	58%
34	57%
35	56%
36	56%
37	55%
38	55%
39	54%
40	54%
41	53%
42	53%
43	53%
44 and greater	52%

SCHEDULE A – RETIREMENT FACTORS

ENHANCED AGE AT BENEFIT COMMENCEMENT DATE	ENHANCED RETIREMENT FACTORS
50	80%
51	84%
52	88%
53	92%
54	96%
55	100%
56	100%
57	100%
58	100%
59	100%
60	100%
61	100%
62	100%
62	100%
63	100%
64	100%
65	100%

The foregoing factors will be interpolated based on the Eligible Participant’s Age rounded to the nearest month.

SCHEDULE B – ENHANCED DEFERRED VESTED PENSION FACTORS

ENHANCED AGE AT TERMINATION		ACTUAL AGE VESTED BENEFITS BEGIN										
		50	51	52	53	54	55	56	57	58	59	>=60
	>=49	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	88.0%	91.0%	94.0%	97.0%	100.0%
	48	69.0%	72.1%	75.2%	78.3%	81.4%	84.5%	87.6%	90.7%	93.8%	96.9%	100.0%
	47	68.0%	71.2%	74.4%	77.6%	80.8%	84.0%	87.2%	90.4%	93.6%	96.8%	100.0%
	46	67.0%	70.3%	73.6%	76.9%	80.2%	83.5%	86.8%	90.1%	93.4%	96.7%	100.0%
	45	66.0%	69.4%	72.8%	76.2%	79.6%	83.0%	86.4%	89.8%	93.2%	96.6%	100.0%
	>45	Reverts to Standard Deferred Vested Pension Plan factors under the regular terms of the Service Annuity Plan.										

The foregoing factors will be interpolated on the Eligible Participant’s Age rounded to the nearest months.

Exhibit 10.6

EXELON CORPORATION

EMPLOYEE SAVINGS PLAN

Amended and Restated Effective as of January 1, 2013

EXELON CORPORATION EMPLOYEE SAVINGS PLAN

TABLE OF CONTENTS

ARTICLE 1

TITLE, PURPOSE AND EFFECTIVE DATES

The title of this Plan shall be the “Exelon Corporation Employee Savings Plan.” This Plan is an amendment and restatement of the Plan as in effect on December 31, 2012, and shall be effective January 1, 2013 in respect of Participants whose employment terminates on or after such date, provided, however, that any provision that specifies a different effective date shall be effective as of such date; and provided, further that, the provisions of Article 9 (relating to participants’ stockholders rights), Article 10 (relating to special participation and distribution rules relating to reemployment of terminated employees and employment by related entities), Article 11 (relating to administration), Article 14 (relating to miscellaneous provisions) and Article 16 (relating to amendment and termination of the Plan) shall be effective for all such persons.

This Plan is designated as a “profit sharing plan” within the meaning of section 1.401-1(a)(2)(ii) of the Regulations; and is also designated as an ERISA section 404(c) Plan within the meaning of section 2550.404c-1 of the Regulations. In addition, the portion of the Plan invested in the Employer Stock Fund described in Section 6.2 is designated as an “employee stock ownership plan” within the meaning of section 4975(e)(7) of the Code and, as such, is designed to invest primarily in “qualifying employer securities” as defined in section 4975(e)(8) of the Code.

ARTICLE 2

DEFINITIONS

As used herein, the following words and phrases shall have the following respective meanings when capitalized:

(1) Administrator. The Company acting through its Director, Employee Benefit Plans & Programs, or such other person or committee appointed pursuant to Section 11.1 (relating to the Administrator, the Investment Office and the Corporate Investment Committee).

(2) Affiliate. (a) A corporation that is a member of the same controlled group of corporations (within the meaning of section 414(b) of the Code) as an Employer, (b) a trade or business (whether or not incorporated) under common control (within the meaning of section 414(c) of the Code) with an Employer, (c) any organization (whether or not incorporated) that is a member of an affiliated service group (within the meaning of section 414(m) of the Code) that includes an Employer, a corporation described in clause (a) of this subdivision or a trade or business described in clause (b) of this subdivision or (d) any other entity that is required to be aggregated with an Employer pursuant to Regulations promulgated under section 414(o) of the Code.

(3) After-Tax Contributions. Contributions made by a Participant pursuant to Section 5.1.

(4) After-Tax Contributions Account. The account established pursuant to Section 7.1 to which shall be credited (i) a Participant's After-Tax Contributions, (ii) any after-tax contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan (including any after-tax contributions transferred to such plan from the Philadelphia Electric Company Tax Reduction Act Stock Ownership Plan) on behalf of such Participant and (iii) earnings (or losses) thereon.

(5) Before-Tax Contributions. Contributions made on behalf of a Participant pursuant to Section 4.1. The term "Before-Tax Contributions" includes Designated Roth Contributions, if any, including Catch-Up Contributions.

(6) Before-Tax Contributions Account. The account established pursuant to Section 7.1 to which shall be credited (i) a Participant's Before-Tax Contributions other than Catch-Up Contributions, (ii) any before-tax contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant and (iii) earnings (or losses) thereon.

(7) Beneficiary. The person or persons entitled under Section 8.5 to receive benefits in the event of the death of a Participant. For any period in which the Plan is not an "ERISA section 404(c) Plan" as defined in the Regulations under section 404(c) of ERISA, each Beneficiary shall be a "named fiduciary" within the meaning of section 402(a)(1) of ERISA for the sole purpose of directing the Trustee with respect to the exercise of shareholder rights pursuant to Article 9 (relating to Participants' stockholder rights).

(8) Catch-Up Contributions. Before-Tax Contributions made pursuant to paragraph (d) of Section 4.1 (relating to Catch-Up Contributions) by a Participant who has attained age 50 before the close of the relevant Plan Year.

(9) Catch-Up Contributions Account. The account established pursuant to Section 7.1 for each Participant who has attained age 50 to which shall be credited a Participant's Catch-Up Contributions

(10) CEG. Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the Merger Agreement).

(11) Code. The Internal Revenue Code of 1986, as amended.

(12) Common Stock. The common stock, without par value, of Exelon Corporation.

(12) Company. Exelon Corporation, a Pennsylvania corporation, or any successor to such corporation that adopts the Plan pursuant to Article 13 (relating to continuance by a successor).

(13) Compensation. The normal base pay under the applicable Exelon East or West payroll of an Employee from an Employer for personal services rendered, including (i) nuclear license premiums for management employees, (ii) meter readers' bonuses, (iii) payments attributable to worker's compensation received from an Employer, (iv) taxable payments received by an employee under the Exelon Corporation Disability Benefit Plan, (v) solely for employees who are employed by Exelon Boston Services LLC who are represented by Local 369 of the Utility Workers Union of America, AFL-CIO, overtime pay, (vi) solely for employees who are represented by IBEW Local Union 15 and covered under the collective bargaining agreement between Commonwealth Edison Company and IBEW Local Union 15, overtime pay, but only amounts paid with respect to hours worked in excess of an Employee's normally scheduled hours, (vii) effective January 1, 2009, differential wage payments (as defined in section 3401(h) of the Code), and excluding (i) salary continuation or lump sum payments under a severance benefit plan, or other severance arrangement, of an Employer, (ii) bonuses or incentive awards (other than meter readers' bonuses), (iii) overtime pay for management employees, (iv) shift premiums, (v) fringe benefits, (vi) other extraordinary payments and (vii) payments made in a form other than cash, but without reduction on account of the Employee's election to have his or her pay reduced pursuant to a qualified cash or deferred arrangement described in section 401(k) of the Code (including any such election to make a Designated Roth Contribution), a qualified transportation fringe benefit program described in section 132(f) of the Code or a cafeteria plan described in section 125 of the Code. For purposes of the preceding sentence, the normal base pay of an Employee who works and is compensated based on a shift schedule other than a basic work week consisting of five regularly scheduled eight-hour work days shall be computed by multiplying the number of regularly scheduled basic work hours for which such Employee is paid by his or her basic hourly rate, determined without regard to any premium payments made at an overtime rate for such work. An Employee's "compensation" (within the meaning of section 415 of the Code) for any Plan Year in excess of the applicable dollar limitation contained in Section 401(a)(17) of the Code (as adjusted for changes in the cost of living pursuant to section 401(a)(17) of the Code), shall be not be taken into account for any purpose under the Plan. Notwithstanding the preceding, effective January 1, 2003, normal base pay shall also include lump sum merit increases to base pay. Notwithstanding the foregoing, an amount classified as Compensation under the preceding paragraphs shall not be Compensation for purposes of the Plan if such amount is paid to an Employee after the Employee's severance from employment unless (i) such amount is regular compensation for services during the Employee's regular working hours or compensation for services outside the Employee's regular working hours and (ii) such amount is paid on or before the later of (A) 2 ½ months after the Employee's severance from employment and (B) the last day of the Plan Year during which the Employee's severance from employment occurs. Finally, in no event shall Compensation for purposes of this Plan include any amount that is not "compensation" within the meaning of section 415(c)(3) of the Code and section 1.415(c)-2 of the Regulations.

(14) Corporate Investment Committee. The Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

(15) Designated Roth Contributions. Before-Tax Contributions designated as Roth contributions pursuant to Section 4.2(e) (relating to Untaxed Contributions and Designated Roth Contributions) by a Participant.

(16) Designated Roth Contributions Account. The account established pursuant to Section 7.1 for each Participant to which shall be credited all Designated Roth Contributions made on behalf of such Participant pursuant to Section 4.2(c) for Plan Years beginning on or after January 1, 2006 and earnings (or losses) thereon for each Participant who is not represented by IBEW Local Union 15 and covered under the collective bargaining agreement between Commonwealth Edison Company and IBEW Local Union 15 ("Local 15 Member") and (b) for Plan Years beginning on or after January 1, 2009 and earning (or losses) thereon for each Participant who is a Local 15 Member.

(17) Disability. A physical or mental condition which, in the judgment of the Administrator, based upon medical reports and other evidence satisfactory to the Administrator, permanently prevents a Participant from satisfactorily performing his or her usual duties or the duties of such other position available to him and for which he is qualified by reason of his or her training, education or experience.

(18) Effective Date. January 1, 2010.

(19) Eligible Employee. An Employee other than (i) an Employee the terms of whose employment are subject to a collective bargaining agreement that does not provide for participation in this Plan, (ii) an Employee on an unpaid leave of absence (except as required by applicable law respecting Military Service), (iii) an Employee paid on the temporary payroll of an Employer who has never completed 1,000 Hours of Service in any period of twelve consecutive months beginning with the Employee's date of employment or any anniversary thereof, (iv) an individual rendering services to an Employer who is not on the payroll of any Employer, (v) as of the Effective Time, an individual who was employed immediately prior to the Effective Time (as such term is defined in the Merger Agreement) at CEG or a facility owned immediately before the Effective Time by CEG and (vi) an individual who is newly employed on or after the Effective Time (as such term is defined in the Merger Agreement) at a facility owned immediately before the Effective Time by CEG. It is expressly intended that an individual rendering services to an Employer pursuant to any of the following agreements shall be excluded from Plan participation pursuant to clause (iv) of this subdivision even if a court or administrative agency determines that such individual is an Employee: (a) an agreement providing that such services are to be rendered as an independent contractor, (b) an agreement with an entity, including a leasing organization within the meaning of section 414(n)(2) of the Code, that is not an Employer or (c) an agreement that contains a waiver of participation in the Plan.

(20) Employee. An individual whose relationship with an Employer is, under common law, that of an employee.

(21) Employer. The Company and any other Affiliate set forth on Appendix I hereto that, with the consent of the Company elects to participate in the Plan in the manner described in Article 12 either with respect to all Employees or a particular group of Employees of such Affiliate and any successor Affiliate that adopts the Plan pursuant to Article 13. If any entity described in the preceding sentence withdraws from participation in the Plan pursuant to Section 12.2, such entity shall thereupon cease to be an Employer.

(22) Employer Matching Contributions. Contributions made by an Employer pursuant to Section 4.3.

(23) Employer Matching Contributions Account. The account established pursuant to Section 7.1 to which shall be credited (i) any Employer Matching Contributions made on behalf of a Participant, (ii) any employer matching contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan (including any employer matching contributions transferred to such plan from the Philadelphia Electric Company Tax Reduction Act Stock Ownership Plan) on behalf of such Participant and (iii) earnings (or losses) thereon.

(24) ERISA. The Employee Retirement Income Security Act of 1974, as amended.

(25) Hour of Service. Each hour for which an Employee is directly or indirectly compensated by, or entitled to receive compensation from, an Employer. For purposes of this subdivision, compensation shall mean the total earnings paid, directly or indirectly, to the Employee by an Employer, including any back pay, irrespective of mitigation of damages, either awarded to the Employee or agreed to by an Employer. The computation of Hours of Service and the periods to which Hours of Service are credited shall be determined under uniform rules adopted by the Administrator in accordance with Department of Labor regulations §2530.200b-2(b), (c) and (f).

(26) Investment Office. The Company acting through the Exelon Investment Office.

(27) Merger Agreement. That Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

(28) Military Service. The performance of duty on a voluntary or involuntary basis in a “uniformed service” (as defined below) under competent authority of the United States government and includes active duty, active duty for training, initial active duty for training, inactive duty training, full-time National Guard duty, and a period for which a person is absent from employment for the purpose of an examination to determine the fitness of the person to perform any such duty. For purposes of the preceding sentence, the term “uniformed service” means the Armed Forces, the Army National Guard and the Air National Guard when engaged in active duty for training, inactive duty training, or full-time National Guard duty, the commissioned corps of the Public Health service, and any other category of persons designated by the President of the United States in time of war or emergency.

(29) Participant. An Eligible Employee who satisfies the conditions set forth in Section 3.1 (relating to eligibility for Participation). An individual shall cease to be a Participant upon the complete distribution, or transfer of his or her account under the Plan. For any period in which the

Plan is not an "ERISA section 404(c) Plan" as defined in Regulations under section 404(c) of ERISA, each Participant shall be a "named fiduciary" within the meaning of section 402(a)(1) of ERISA for the sole purpose of directing the Trustee with respect to the exercise of shareholder rights pursuant to Article 9 (relating to Participants' stockholder rights).

(30) Plan. The plan herein set forth, and as from time to time amended.

(31) Plan Year. The twelve-month period beginning on each January 1.

(32) Qualified Reservist. The term "Qualified Reservist" shall mean an individual who is (i) a member of a reserve component (as defined in chapter 1 of title 37, United States Code) and (ii) ordered or called to active duty for a period in excess of 179 days or for an indefinite period, after September 11, 2001.

(33) Regulations. Written final or temporary promulgations of the Department of Labor construing Title I of ERISA or the Internal Revenue Service construing the Code.

(34) Rollover Account. The account established pursuant to Section 7.1 to which shall be credited (i) any rollover contribution made by or on behalf of an Eligible Employee or a Participant, (ii) any rollover contribution transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant and (iii) earnings (or losses) thereon.

(35) Spouse. The individual who is a husband or wife of a Participant as the result of a legal union between one man and one woman, within the meaning of the Defense of Marriage Act.

(36) Termination Date. (a) The date an Employee quits, retires, is discharged from employment by an Employer or dies, (b) the date the Employee's employer ceases to be an Employer on account of its sale to a party or parties that do not qualify as an Affiliate of any Employer, (c) the first anniversary of the Employee's first date of absence from employment by an Employer for any other reason, except as provided in clause (d) or (e) below, (d) in the case of an Employee who is absent from employment for maternity or paternity reasons, the second anniversary of the first date of such absence or (e) the last date following a period of Military Service as of which the Employee has reemployment rights under applicable law. For purposes of this subdivision, an absence from employment for maternity or paternity reasons means an absence (1) by reason of the pregnancy of the Employee, (2) by reason of the birth of a child of the Employee, (3) by reason of the placement of a child with the Employee in connection with the adoption of such child by such Employee or (4) for purposes of caring for such child for a period beginning immediately following such birth or placement. Notwithstanding the foregoing sentences, an Employee's absence from employment for maternity or paternity reasons or for Military Service shall not be considered in determining the Employee's Termination Date unless the Employee, upon the Administrator's request, provides certification that the leave was taken for one of the reasons enumerated in the preceding sentence.

(37) Trust. The trust created by agreement between the Company and the Trustee, as from time to time amended.

(38) Trust Fund. All money and property of every kind of the Trust held by the Trustee pursuant to the terms of the Trust agreement.

(39) Trustee. The trustee that executes the Trust instrument provided for in Article 6, or any successor trustee or, if there is more than one trustee acting at any time, all of such trustees collectively.

(40) Untaxed Contributions. Before-Tax Contributions not designated as Designated Roth Contributions pursuant to Section 4.2(e) (relating to Untaxed Contributions and Designated Roth Contributions) by a Participant.

(41) Untaxed Contributions Account. The account established pursuant to Section 7.1 for each Participant to which shall be credited (a) all Before-Tax Contributions that are made on behalf of the Participant pursuant to Section 4.2 for Plan Years beginning prior to January 1, 2006 with respect to a Participant who is not a Local 15 Member and for Plan Years beginning before January 1, 2009 with respect to a Participant who is a Local 15 Member, (b) any before-tax contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant, (c) all Before-Tax Contributions that are Untaxed Contributions made pursuant to Section 4.2 for Plan Years beginning on or after January 1, 2006 with respect to a Participant who is not a Local 15 Member and for Plan Years beginning before January 1, 2009 with respect to a Participant who is a Local 15 Member, and (d) earnings (or losses) thereon.

(42) Valuation Date. Each business day, as determined by the Trustee, or such other days as the Administrator may designate.

(43) VRU. The telephonic voice response unit designated by the Administrator, which may be used to make certain elections under the Plan. The VRU shall require each Participant, or Beneficiary, as the case may be, to provide such identification data as may, from time to time, be required by the VRU. The Administrator shall cause to be kept such records of VRU activity as it shall deem necessary or appropriate, and such records shall constitute valid authorization of the elections made by each Participant and Beneficiary for all purposes of the Plan and applicable Regulations. No written authorization shall be required from a Participant or Beneficiary after an election has been made by calling the VRU.

ARTICLE 3

PARTICIPATION

Section 3.1. Eligibility for Participation.

Each Eligible Employee who immediately before the Effective Date was a Participant in the Plan shall continue to be a Participant as of the Effective Date. Each other Eligible Employee who is a member of a bargaining unit represented by IBEW Local Union 15 shall be eligible to become a Participant on the first day of the payroll period coinciding with or next following the date he or she has completed three months of employment with an Employer (regardless of the number of Hours of Service actually performed). Each other Eligible Employee who is not a member of a bargaining unit represented by IBEW Local Union 15 shall be eligible to become a Participant on the first day of the payroll period coinciding with or next following the date of his or her employment.

Section 3.2. Applications for Before-Tax Contributions and After-Tax Contributions.

(a) Regular Payroll Before-Tax and After-Tax Contributions. Each Eligible Employee who desires to commence Before-Tax Contributions or After-Tax Contributions shall make a request in the manner prescribed by the Administrator specifying the Employee's chosen rate of Before-Tax Contributions for each payroll period or his or her chosen rate of After-Tax Contributions for each payroll period, or both. Such request shall authorize the Employee's Employer to reduce the Eligible Employee's Compensation by the amount of any such Before-Tax Contributions, to make regular payroll deductions of any such After-Tax Contributions or both, as the case may be. The request shall also specify the Employee's investment elections pursuant to Section 7.1(b) and shall evidence the Employee's acceptance of and agreement to all provisions of the Plan. In addition, an Eligible Employee who is not a member of a bargaining unit represented by IBEW Local Union 15 on the date of his or her employment may elect, in accordance with the provisions of this paragraph (a), to become a Participant on the first day of the payroll period coinciding with or next following such date. All requests to commence contributions pursuant to this paragraph (a) shall be effective as of such time after the Administrator (or its delegate) receives such request as shall be established by the Administrator, provided, that all such requests shall be effective on the first day of a payroll period commencing not more than 30 days after receipt thereof by the Administrator (or its delegate).

(b) Quarterly Incentive Award Before-Tax Contributions. With respect to quarterly incentive awards earned prior to January 1, 2002, each Eligible Employee may request, in the manner prescribed by the Administrator, to reduce his or her compensation by an amount equal to 100 percent of any such quarterly incentive awards that would otherwise be paid to such Participant; provided, however, that for the 2001 Plan Year, such reduction shall be available solely with respect to quarterly incentive awards payable on or after the later of (i) March 31, 2001 and (ii) the first date thereafter which the Administrator determines is administratively practicable with respect to Employees of such Participant's Employer. Before-Tax Contributions pursuant to this paragraph (b) shall be invested in accordance with the Participant's investment election under paragraph (a) of this Section 3.2 (or, if no such election is in effect, in accordance with an investment election made by such Participant in the manner prescribed by the Administrator).

(c) Automatic Enrollment for Certain Employees. (i) Deemed Election of Default Before-Tax Contributions. A Participant whose hire date is on or after April 6, 2009 and who does not make an election pursuant to paragraph (a) of this Section 3.2 to make Before-Tax Contributions or After-Tax Contributions shall be deemed to have elected to make Before-Tax Contributions ("Default Before-Tax Contributions") equal to 3 percent ("Default Percentage") of his or her Compensation for each payroll period and to have his or her Employer reduce his or her Compensation by the amount thereof. Such Participant's Default Percentage will increase by 1 percent each Plan Year, beginning with the second Plan Year that begins after the Default Percentage first applies to the Participant, until it reaches 5 percent. The increase will be effective March 1 of each applicable Plan Year. Notwithstanding the foregoing, in the event a Participant's initial Default Before-Tax Contribution occurs during the period commencing on December 1 and ending the last day of February, the initial increase to such Participant's Default Percentage shall commence on the March 1 of the calendar year following the first anniversary of the Participant's initial Default Before-Tax Contribution. The effective date of such Participant's deemed election shall be 90 days after the Participant receives a notice of his or her rights and obligations under this paragraph (c)(i) (the "Automatic Enrollment Notice"). During the 90-day period after the Participant receives the Automatic Enrollment Notice, the Participant shall have an opportunity to make an affirmative election to (1) not have any Default Before-Tax Contributions made on his or her behalf or (2) have Before-Tax Contributions made in a different amount or percentage of Compensation by giving direction to the Administrator (or its delegate) in the manner prescribed by the Administrator. Any deemed election described in this paragraph (c)(i) shall be effective only with respect to Compensation not currently available to the Participant. Each Participant whose hire date is on or after April 6, 2009 shall be a "covered employee" for purposes of section 1.414(w)-1(e)(3) of the Regulations, regardless of whether such Participant makes an affirmative election regarding Before-Tax Contributions. Notwithstanding the foregoing, an Employee who on or after April 6, 2009 becomes eligible to participate in the Plan as a result of the Employee's rehire by an Employer shall not be deemed to have made an election automatically to have Before-Tax Contributions made on his or her behalf pursuant to this paragraph (c)(i) or deemed to be a "covered employee."

(ii) Withdrawal of Default Before-Tax Contributions. A covered employee deemed to elect Default Before-Tax Contributions pursuant to paragraph (c)(i) may elect, no later than 90 days after the first payroll date that the first Default Before-Tax Contributions on behalf of the covered employee occurs, to receive a distribution equal to the amount of all such contributions (adjusted for earnings and losses and reduced by any applicable fees) made with respect to the covered employee through the earlier of (1) the pay date for the second payroll period that begins after the covered employee's withdrawal request and (2) the first pay date that occurs after 30 days following the covered employee's request. An election by a covered employee to withdraw Default Before-Tax Contributions pursuant to this paragraph (c)(ii) shall be deemed to be an election by the covered employee, as of the date of the withdrawal election, to reduce his Before-Tax Contribution percentage to 0 percent (subject to any affirmative election by the covered employee to the contrary).

Section 3.3. Transfer to Affiliates.

If a Participant is transferred from one Employer to another Employer or from an Employer to an Affiliate, such transfer shall not terminate the Participant's participation in the Plan and such Participant shall continue to participate in the Plan until an event occurs that would have terminated his or her participation had the Participant continued in the service of an Employer until the occurrence of such event; provided, however, that a Participant shall not be entitled (i) to make contributions to the Plan, or (ii) to have contributions made on his or her behalf to the Plan during any period of employment by any Affiliate that is not an Employer with respect to such Participant. Periods of employment with an Affiliate shall be taken into account only to the extent set forth in Section 10.4 (relating to employment by Affiliates). Payments received by a Participant from an Affiliate that is not an Employer with respect to such Participant shall not be treated as compensation for any purposes under the Plan.

ARTICLE 4

EMPLOYER CONTRIBUTIONS

Section 4.1. Before-Tax Contributions.

(a) Initial Election Respecting Regular Payroll Before-Tax Contributions. Subject to the limitations set forth in Sections 4.2 (relating to the 402(g) annual limit on Before-Tax Contributions), 4.4 (relating to limitations on contributions for highly compensated Eligible Employees), 4.5 (relating to the limitation on Employer contributions) and 7.4 (relating to limitations on allocations imposed by section 415 of the Code), each Employer shall contribute (i) on behalf of each Participant who is an Eligible Employee of such Employer and is a member of a bargaining unit represented by IBEW Local Union 15 an amount equal to a whole percentage not less than 1 and not more than 15 percent of such Participant's Compensation for each payroll period as designated by the Participant in his or her request pursuant to Section 3.2(a), and (ii) on behalf of any other Participant who is an Eligible Employee of such Employer an amount equal to a whole percentage not less than 1 and not more than 20 percent and, effective as of January 1, 2006, 50 percent, of such Participant's Compensation for each payroll period as designated by the Participant on his or her request pursuant to Section 3.2(a). Before-Tax Contributions described in the preceding sentence shall be delivered to the Trustee no less frequently than bi-weekly. In addition, if back-pay is awarded to a Participant who is an Eligible Employee and any portion of such back-pay constitutes Compensation as defined in subdivision (13) of Article 2 (relating to the definition of Compensation), the Employer of such Participant shall contribute on behalf of such Participant an amount equal to the Before-Tax Contribution percentage, which was most recently chosen by the Participant in his or her request pursuant to Section 3.2(a), of such back-pay that constitutes Compensation. A Before-Tax Contribution described in the preceding sentence shall be treated under the Plan in the same manner as all other Before-Tax Contributions and shall be delivered to the Trustee as soon as practicable after the back-pay is paid to the Participant.

If a Participant receives a hardship withdrawal pursuant to Section 8.1(a), then: (1) all Before-Tax Contributions made on behalf of such Participant pursuant to this Section 4.1 and After-Tax Contributions made by the Participant pursuant to Section 5.1 shall cease beginning with the first payroll period beginning after the date on which the Participant receives such hardship withdrawal; and (2) such Participant shall not again be eligible to elect such contributions until the first payroll period that coincides with or follows the date on which contributions ceased by six months.

(b) Changes in the Rate or Suspension of Regular Payroll Before-Tax Contributions. A Participant's Before-Tax Contributions pursuant to paragraph (a) of this Section 4.1 shall continue in effect at the rate designated by a Participant in his or her request until the Participant changes such designation or suspends such contributions. A Participant may change such designation at any time by giving direction to the Administrator (or its delegate) in the manner prescribed by the Administrator. Any such direction shall be limited to the contribution rates described in paragraph (a) of this Section 4.1.

A Participant may suspend future Before-Tax Contributions pursuant to paragraph (a) of this Section 4.1 by giving notice to the Administrator (or its delegate) in the manner prescribed by the Administrator. A Participant who has ceased Before-Tax Contributions pursuant to this subsection may resume Before-Tax Contributions by so directing the Administrator (or its delegate) in the manner prescribed by the Administrator. All such directions to change the rate of, suspend or resume Before-Tax Contributions shall be effective as of such time after the Administrator (or its delegate) receives any such direction as shall be established by the Administrator, provided that such direction shall be effective on the first day of a payroll period commencing not more than 30 days after receipt thereof by the Administrator (or its delegate).

(c) Elections Respecting Quarterly Incentive Award Before-Tax Contributions. With respect to quarterly incentive awards earned prior to January 1, 2002, and subject to the limitations set forth in subdivision (13) of Article 2 (relating to the $170,000 limitation on Compensation) and Sections 4.2 (relating to the 402(g) limit on Before-Tax Contributions), 4.4 (relating to limitations on contributions for highly compensated Eligible Employees), 4.5 (relating to the limitation on Employer contributions) and 7.4 (relating to limitations on allocations imposed by section 415 of the Code), each Employer shall contribute on behalf of each Participant who has filed a request in accordance with Section 3.2(b) an amount equal to 100 percent of the amount of any such quarterly incentive awards payable to such Participant on or after the effective date of such request. A Participant's Before-Tax Contributions pursuant to this paragraph (c) shall continue in effect until the Participant suspends such contributions. A Participant may suspend such contributions by giving direction to the Administrator (or its delegate) in the manner prescribed by the Administrator. Any such direction to suspend Before-Tax Contributions pursuant to this paragraph (c) shall be effective beginning with the quarterly incentive award payable in the calendar quarter immediately following the calendar quarter in which such direction is received by the Administrator (or its delegate). Before-Tax Contributions pursuant to this paragraph (c) shall be delivered to the Trustee not later than the fifteenth business day of the month following the month in which the related quarterly incentive award is payable.

(d) Catch-Up Contributions. Effective for payroll periods beginning on or after August 1, 2002, each Participant who pursuant to paragraph (a) of this Section 4.1 is eligible to make Before-Tax Contributions for any Plan Year and who shall attain age 50 before the close of such Plan Year shall be eligible to have Before-Tax Contributions made in addition to those described in paragraph (a) of this Section 4.1 ("Additional Before-Tax Contributions") if no other Before-Tax Contributions to be made pursuant to paragraph (a) of this Section 4.1 may be made to the Plan for such payroll period by reason of the limitations of Section 4.2 (relating to the 402(g) annual limit on Before-Tax Contributions). Notwithstanding the preceding sentence, in no event shall the amount of Additional Before-Tax Contributions exceed (i) in the case of a Participant who is represented by IBEW Local Union 15 and covered under that certain Collective Bargaining Agreement dated September 15, 2000 between Commonwealth Edison Company and IBEW Local Union 15, 40 percent of such Participant's Compensation for any payroll period, and (ii) in the case of any other Participant, 50 percent of such Participant's Compensation for any payroll period. Such Additional Before-Tax Contributions shall be elected, made, suspended, resumed and credited in a manner similar to that described in paragraphs (a), (b) and (c) of this Section 4.1 and in accordance with and subject to such additional rules and limitations of section 414(v) of the

Code and otherwise as the Administrator determines. To the extent such Additional Before-Tax Contributions are not “Catch-Up Contributions” as defined for purposes of section 414(v) of the Code, they shall be taken into account, and to the extent such Additional Before-Tax Contributions are Catch-Up Contributions they shall not be taken into account, for purposes of Article 4 or 7 or other provisions of the Plan implementing the required limitations of sections 401(k)(3), 401(k)(11), 401(k)(12), 402(g), 404, 410(b), 415 or 416 of the Code, as applicable.

Section 4.2. 402(g) Annual Limit on Before-Tax Contributions.

(a) General Rule. Notwithstanding the provisions of Section 4.1 (relating to Before-Tax Contributions), a Participant’s Before-Tax Contributions for any calendar year, together with amounts contributed under all other plans and arrangements maintained by an Employer or Affiliate and described in sections 401(k), 408(k), 408(p) or 403(b) of the Code, and excluding any Additional Before-Tax Contributions made to the Plan pursuant to paragraph (d) of Section 4.1 which are Catch-Up Contributions described in such paragraph or Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2, shall not exceed the applicable dollar amount under section 402(g) of the Code (as adjusted for cost-of-living increases in accordance with section 402(g)(5) of the Code) for such calendar year.

(b) Correction of Excess Before-Tax Contributions. If for any calendar year a Participant determines that the aggregate of the (i) Before-Tax Contributions to this Plan, excluding any Additional Before-Tax Contributions made to the Plan pursuant to paragraph (d) of Section 4.1 which are Catch-Up Contributions described in such paragraph, and (ii) amounts contributed under other plans or arrangements described in sections 401(k), 408(k) or 403(b) of the Code will exceed the limit imposed by paragraph (a) of this Section 4.2 for the calendar year in which such contributions were made (“Excess Before-Tax Contributions”), such Participant shall, pursuant to such rules and at such time following such calendar year as determined by the

Administrator, be allowed to submit a written request that the Excess Before-Tax Contributions plus any income and minus any loss allocable thereto be distributed to him or her. The request described in this subsection shall be made in the manner and form prescribed by the Administrator and shall state the amount of the Participant's Excess Before-Tax Contributions for the calendar year. The request shall be accompanied by the Participant's written statement that if such Excess Before-Tax Contributions are not distributed, such Excess Before-Tax Contributions, when added to amounts deferred under other plans or arrangements described under sections 401(k), 408(k), or 403(b) of the Code, excluding any contributions which are Catch-Up Contributions described in section 414(v) of the Code, will exceed the limit for such Participant under section 402(g) of the Code. A distribution of Excess Before-Tax Contributions (reduced by any amounts recharacterized or distributed pursuant to paragraph (e)(1) of Section 4.4 (relating to adjustments to comply with section 401(k)(3) of the Code)) shall be made no later than the applicable time period set forth in the Code and Regulations thereunder following the end of the Plan Year for which such Excess Before-Tax Contributions were made, plus any income and minus any loss allocable thereto through the end of such Plan Year. The amount of any income or loss allocable to such Excess Before-Tax Contributions shall be determined pursuant to applicable Regulations. If Excess Before-Tax Contributions are distributed pursuant to this Section 4.2, any corresponding Employer Matching Contributions allocated to the Participant's Employer Matching Contributions Account, adjusted for income or loss pursuant to Regulations, to which such Participant would be entitled under Section 8.3 (relating to distributions upon termination of employment) if such Participant had terminated employment on the last day of the calendar year during which contributions were made (or earlier if such Participant actually terminated employment at an earlier date) shall be distributed to such Participant and any remaining amount of such corresponding Employer Matching Contributions, adjusted for income or loss, shall be forfeited.

Notwithstanding the provisions of this paragraph, any such Excess Before-Tax Contributions shall be treated as “annual additions” for purposes of Section 7.4 (relating to limitations on allocations imposed by section 415 of the Code) and shall not be disregarded as Before-Tax Contributions for purposes of determining the average deferral percentage described in Section 4.4(d)(1) or, to the extent applicable, the average contribution percentage described in Section 4.4(d)(2), except that in the case of a non-highly compensated eligible employee, as that term is defined in Section 4.4(d)(4), such Excess Before-Tax Contributions shall be ignored to the extent that such contributions are prohibited pursuant to section 401(a)(30) of the Code, which requires that Before-Tax Contributions not exceed the limit described in paragraph (a) of Section 4.2 (relating to the annual limit on Before-Tax Contributions). Any distribution of Excess Before-Tax Contributions to a Participant shall be treated as a distribution of the Untaxed Contributions, up to the extent Untaxed Contributions have been made by such Participant to the Plan for such Plan Year and, to the extent that distributions of Excess Before-Tax Contributions to such Participant exceed the Participant’s Untaxed Contributions for such Plan Year, the distributions of Excess Before-Tax Contributions shall be treated as Designated Roth Contributions made by the Participant to the Plan for the Plan Year.

(c) Untaxed Contributions and Designated Roth Contributions. Effective for Before-Tax Contributions made (i) in the case of a Participant who is not a Local 15 Member, for the 2006 Plan Year and thereafter, and (ii) in the case of a Participant who is a Local 15 Member, for the 2009 Plan Year and thereafter, an election made by a Participant to commence, change, suspend or resume Before-Tax Contributions pursuant to this Section 4.2 shall designate the portion of such contributions that are to be Designated Roth Contributions includible in the Participant’s gross income when made pursuant to section 402A of the Code. Such designation is irrevocable with respect to contributions made or to be made with respect to Compensation currently available. Any such election made by a Participant which does not expressly designate a portion of Before-Tax Contributions as Designated Roth Contributions shall be deemed to designate no portion of Before-Tax Contributions as Designated Roth Contributions. Any Before-Tax Contributions that are not Designated Roth Contributions are referred to herein as Untaxed Contributions.

Section 4.3. Employer Matching Contributions.

(a) Amount of Contributions. Subject to the limitations set forth in Sections 4.4 (relating to limitations on contributions for highly compensated Eligible Employees), 4.5 (relating to the limitations on Employer contributions) and 7.4 (relating to limitations on allocations imposed by section 415 of the Code), and except as otherwise provided below, each Employer shall contribute the following for each payroll period on behalf of each Participant who is an Employee of such Employer:

(i) Effective beginning with the first payroll period in January 1, 2009, for each Participant who is a member of a bargaining unit represented by IBEW Local Union 15, an amount equal to 100 percent of Matched Contributions, as defined below, but only to the extent that Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period;

(ii) For each Participant who is covered under the collective bargaining agreement between Exelon Power Services LLC and Local 369 of the Utility Workers Union of America, AFL-CIO, if such Participant has completed less than 5 months of service with an Employer, no contribution shall be made; if such Participant has completed more than 5 months of service but fewer than 12 months of service with an Employer, an amount equal to 50% of Matched Contributions, as defined below, but only the extent that Matched Contributions do not exceed 3 percent of the Participant's Compensation for the payroll period; if such Participant has completed at least 12 months of service with an Employer, an amount equal to 100% of Matched Contributions, but only to the extent that Matched Contributions do not exceed 3 percent of the Participant's Compensation for the payroll period. For purposes of this paragraph, a month of service shall mean a consecutive period of employment during which the Employee is employed by an Employer ending on the monthly anniversary of the Employee's date of hire. A Participant who is credited with an additional month of service during a pay period and becomes eligible to receive an increased Employer Matching Contribution, shall not be entitled to receive an increased Employer Matching Contribution until the first full payroll period following the payroll period in which such Participant is credited with such additional month of service;

(iii) For each Participant who is classified as a non-exempt craft employee or clerical employee assigned to the Peachbottom, Limerick, Outage Services East or Texas generating plant, an amount equal to 100 percent of Matched Contributions, as defined below, but only to the extent that Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period; and

(iv) For each other Participant, an amount equal to 60 percent of Matched Contributions, as defined below, but only to the extent that Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period.

In addition, each Participant described in clause (iv) of the preceding paragraph shall be eligible to receive a "Profit Sharing Matching Contribution," provided that such Participant either (i) is an Employee of such Employer on the last day of such Plan Year, (ii) is not employed on such day as a result of an approved unpaid leave of absence during such Plan Year, (iii) terminates employment during such Plan Year (1) after attaining age 50 and completing at least 10 years of service, as determined by the Administrator, (2) as a result of circumstances entitling the Participant to separation benefits under an Employer's severance benefit plan, (3) as a result of a disability that entitles the Participant to benefits under an Employer's long-term disability plan, or (4) on account of the Participant's death. The "Profit Sharing Matching Contribution" shall be an amount (if any) determined by the Board of Directors of the Company (or the Compensation Committee thereof) in its sole discretion based on attainment of specified performance goals, and not exceeding 60% of a Participant's Matched Contributions, as defined below, for each payroll period, but only to the extent that such Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period.

For purposes of this Section 4.3, “Matched Contributions” means the sum of (i) the Before-Tax Contributions made on behalf of the Participant for a payroll period, excluding Before-Tax Contributions made with respect to any quarterly incentive awards pursuant to paragraph (b) of Section 3.2, excluding Additional Before-Tax Contributions which are Catch-Up Contributions described in section 414(v) of the Code and excluding Default Before-Tax Contributions distributed pursuant to paragraph (c)(ii) of Section 3.2 (relating to withdrawal of Default Before-Tax Contributions), and (ii) the After-Tax Contributions made by the Participant for such payroll period. Any Employer Matching Contributions made by an Employer with respect to Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2, plus any earnings, shall be forfeited and used to reduce future Employer Matching Contributions made by an Employer pursuant to this Section.

In addition to the Employer Matching Contributions described above, in the case of a New England Plan Participant, as defined in Supplement IV attached hereto, whose Before-Tax Contributions exceed the limit described in Section 4.2 (relating to the 402(g) annual limit on Before-Tax Contributions), an additional Employer Matching Contribution shall be made on behalf of such Participant in an amount equal to the amount described in clause (iii) above assuming that such Participant had continued making the same rate of Before-Tax Contributions that were in effect with respect to such Participant at the time such Before-Tax Contributions exceeded the limit described in Section 4.2.

(b) Special Part-Time Employees. Notwithstanding paragraph (a) hereof, no Employer shall make a contribution pursuant to this Section 4.3 on behalf of any Participant who is a “part-time regular employee” as defined in an Agreement dated July 23, 1993 between the Company and the System Council U-25, I.B.E.W. (the “July 23, 1993 Agreement”), unless one of the following applies:

(1) the Participant had in effect on July 23, 1993 an authorization to make contributions under the Plan as then in effect and elected pursuant to the July 23, 1993 Agreement and request by the Company to become a part-time regular employee during the initial staffing period that began July 23, 1993 and ended December 31, 1993 (the “Initial Staffing Period”);

(2) the Participant had in effect on the date the Participant became a part-time regular employee an authorization to make contributions under the Plan as then in effect and chose the Option II Benefits Package as described in the July 23, 1993 Agreement, as amended;

(3) the Participant did not have in effect on the date the Participant became a part-time regular employee an authorization to make contributions under the Plan as then in effect and elected pursuant to the July 23, 1993 Agreement and request by the Company to become a part-time regular employee during the Initial Staffing Period; provided such Participant had in effect on any date after December 24, 1995 and before February 20, 1996 an authorization to make contributions under the Plan; or

(4) the Participant elected other than pursuant to the July 23, 1993 Agreement to become a part-time regular employee during the Initial Staffing Period; provided that such Participant had in effect on any date after December 24, 1995 and before February 20, 1996 and authorization to make contributions under the Plan.

(c) Time of Delivery of Contributions. Employer Matching Contributions for any Plan Year shall be delivered to the Trustee at the same time the Before-Tax contributions or After-Tax Contributions to which such Employer Matching Contributions relate are delivered to the Trustee.

Section 4.4. Limitations on Contributions for Highly-Compensated Eligible Employees.

(a) Limits Imposed by Section 401(k)(3) of the Code. Notwithstanding the provisions of Section 4.1 (relating to Before-Tax Contributions), if the Before-Tax Contributions for a Plan Year fail, or in the judgment of the Administrator are likely to fail, to satisfy both of the tests set forth in paragraphs (1) and (2) of this subsection, the adjustments prescribed in paragraph (e)(1) of this Section 4.4 shall be made.

(1) The average deferral percentage for the group consisting of highly compensated eligible employees of all Employers does not exceed the product of the average deferral percentage for the group consisting of non-highly compensated eligible employees multiplied by 1.25.

(2) The average deferral percentage for the group consisting of highly compensated eligible employees of all Employers (i) does not exceed the average deferral percentage for the group consisting of non-highly compensated eligible employees by more than two percentage points, and (ii) does not exceed two times the average deferral percentage for such group.

Effective for payroll periods beginning on or after August 1, 2002, any Additional Before-Tax Contributions which are "Catch-Up Contributions" described in paragraph (d) of Section 4.1 shall not be considered as Before-Tax Contributions for purposes of determining whether the tests set forth in paragraphs (1) and (2) of this subsection are satisfied or for purposes of making any adjustments prescribed in paragraph (e) of this Section 4.4.

(b) Limits Imposed by Section 401(m) of the Code. Notwithstanding the provisions of Section 4.3 (relating to Employer Matching Contributions) and Section 5.1 (relating to After-Tax Contributions), if the Employer Matching Contributions and After-Tax Contributions for a Plan Year fail, or in the judgment of the Administrator are likely to fail, to satisfy both of the tests set forth in paragraphs (1) and (2) of this subsection, the adjustments prescribed in paragraph (e)(2) of this Section 4.4 shall be made.

(1) The average contribution percentage for the group consisting of highly compensated eligible employees of all Employers does not exceed the product of the average contribution percentage for the group consisting of non-highly compensated eligible employees multiplied by 1.25.

(2) The average contribution percentage for the group consisting of highly compensated eligible employees of all Employers (i) does not exceed the average contribution percentage for the group consisting of non-highly compensated eligible employees by more than two percentage points, and (ii) does not exceed two times the average contribution percentage for such group.

(c) Aggregate Limit on Contributions. **Deleted in its entirety.**

(d) Definitions. For purposes of this Section 4.4:

(1) the “average deferral percentage” for a group of Eligible Employees with respect to a Plan Year shall be the average of the ratios, calculated separately for each Eligible Employee in such group to the nearest one-hundredth of one percent, of the Before-Tax Contributions made for the benefit of such Eligible Employee to the total compensation paid to such Eligible Employee for the portion of such Plan Year during which such Eligible Employee was a Participant, except that no Additional Before-Tax Contributions which are “Catch-Up Contributions” described in paragraph (d) of Section 4.1 or Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2 shall be considered as Before-Tax Contributions for purposes of determining a Participant’s average deferral percentage;

(2) the “average contribution percentage” for a group of Eligible Employees with respect to a Plan Year shall be the average of the ratios, calculated separately for each Eligible Employee in such group to the nearest one-hundredth of one percent, of the Employer Matching Contributions made, After-Tax Contributions made and, in the Administrator’s sole discretion, to the extent permitted under Regulations or otherwise under the Code, the Before-Tax Contributions made during such year for the benefit of such Eligible Employee, except that no Additional Before-Tax Contributions which are “Catch-Up Contributions” described in paragraph (d) of Section 4.1, shall be considered as Before-Tax Contributions for purposes of determining a Participant’s average contribution percentage, to such Eligible Employee’s compensation for the portion of such Plan Year during which such Eligible Employee was a Participant;

(3) the term “highly compensated eligible employee” shall mean any Eligible Employee who is a Participant, who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its Affiliates when ranked on the basis of compensation paid during such preceding Plan Year;

(4) the term “non-highly compensated eligible employee” shall mean any Eligible Employee who is a Participant, who performs services in the determination year and is not a highly compensated eligible employee;

(5) the term “compensation” shall have the meaning set forth in section 414(s) of the Code or, in the discretion of the Administrator, any other meaning in accordance with the Code for these purposes, except that for purposes of determining whether an Eligible Employee is a “highly compensated eligible employee”, as described in paragraph (d)(3) of this Section 4.4, “compensation” shall have the meaning set forth in section 415(c)(3) of the Code;

(6) if this Plan and one or more other plans of the Employer to which Before-Tax Contributions, After-Tax Contributions, or qualified nonelective contributions (as such term is defined in section 401(m)(4)(C) of the Code) are made are treated as one plan for purposes of section 410(b) of the Code, such plans shall be treated as one plan for purposes of this Section. If a highly compensated eligible employee participates in this Plan and one or more other plans of the Employer to which any such contributions are made, all such contributions shall be aggregated for purposes of this Section 4.4; and

(7) if this Plan benefits Employees who are included in a unit of employees covered by a collective bargaining agreement and employees who are not included in such collective bargaining unit, this Plan shall be treated as comprising two or more separate plans, as determined by the Administrator in accordance with applicable Regulations, for purposes of this Section 4.4. If such other plan has a plan year that is different from the Plan Year of this Plan, then the highly compensated eligible employee's contributions made to such other plan during the Plan Year of this Plan shall be aggregated with contributions of the same type made to this Plan for such Plan Year for purposes of determining the average deferral percentage and average contribution percentage for this Plan for such Plan Year for the group of highly compensated eligible employees.

This paragraph is inserted at the request of the Internal Revenue Service in order to obtain a favorable determination letter. In computing the "average deferral percentage" for a group of Eligible Employees with respect to a Plan Year, the Before-Tax Contributions that will be taken into account for such Plan Year will be only those that relate to compensation that would have been received by the Eligible Employee in the Plan Year or is attributable to services performed by the Eligible Employee in the Plan Year and would have been received by the Eligible Employee within 2-1/2 months after the close of the Plan Year. In computing the "average contribution percentage" for a group of Eligible Employees with respect to a Plan Year, (i) an After-Tax Contribution will be taken into account only if it is paid to the Trust during such Plan Year or paid to an agent of the Plan and transmitted to the Trust within a reasonable time after the end of the Plan Year; (ii) an excess contribution that is recharacterized will be taken into account during the Plan Year in which the contribution would have been received in cash by the Eligible Employee had the Eligible Employee not elected to defer the contribution; (iii) an Employer Matching Contribution will be taken into account only if it is made on account of the Eligible Employee's Before-Tax Contributions or After-Tax Contributions, allocated to the Eligible Employee's Account as of a date within that Plan Year and paid to the Trust by the end of the twelfth month following the close of such Plan Year; and (iv) qualified matching contributions which are used to meet the requirements of section 401(k)(3)(A) of the Code are not to be taken into account for purposes of the actual deferral percentage test of section 401(m) of the Code. To the extent required by law, the following will be treated as separate plans for purposes of sections 401(a)(4) and 410(b) of the Code: (i) the portion of the Plan that is a 401(k) plan, (ii) the portion of the Plan that is a section 401(m) plan; (iii) the portion of the plan that provides for contributions other than elective, employee or matching; (iv) the portion of the Plan that is an ESOP; and (v) the portion of the plan that is not an ESOP.

(e) Adjustments to Comply with Limits.

(1) Adjustments to Comply with Section 401(k)(3) of the Code. The Administrator shall cause to be made such periodic computations as it shall deem necessary or appropriate to determine whether either of the tests set forth in paragraph (a)(1) or (a)(2) of this Section 4.4 shall be satisfied during a Plan Year, and, if it appears to the Administrator that neither of such tests will be satisfied, the Administrator shall take such steps as it deems necessary or appropriate to reduce or otherwise adjust the Before-Tax Contributions contributed or to be contributed for all or a portion of such Plan Year on behalf of Participants who are highly compensated eligible employees to the extent necessary in order for one of such tests to be satisfied. If, as of the end of the Plan Year, the Administrator determines that, notwithstanding any adjustments made pursuant to the

preceding sentence, neither of the tests set forth in paragraph (a)(1) and (a)(2) of this Section 4.4 shall be satisfied with respect to such Plan Year, the total amount by which Before-Tax Contributions must be reduced in order to satisfy either such test shall be calculated in the manner prescribed by section 401(k)(8)(B) of the Code (the “excess contributions amount”). The Before-Tax Contributions made on behalf of the Participant who is a highly compensated eligible employee and whose actual dollar amount of Before-Tax Contributions is the highest shall be reduced until such dollar amount equals the next highest actual dollar amount of Before-Tax Contributions made for such Plan Year on behalf of any highly compensated employee, or until the total reduction equals the excess contributions amount. If further reductions are necessary, then the Before-Tax Contributions on behalf of each Participant who is a highly compensated eligible employee and whose actual dollar amount of Before-Tax Contributions is the highest (after the reduction described in the preceding sentence) shall be reduced in accordance with the previous sentence. Such reductions shall continue to be made to the extent necessary so that the total reduction equals the excess contributions amount.

To the extent that the sum of such reductions with respect to a Participant and the amount of other After-Tax Contributions allocated to such Participant’s After-Tax Contributions Account does not exceed 20 percent (10 percent in the case of a Participant who is a member of a bargaining unit represented by IBEW Local Union 15) of the Participant’s Compensation, the amount of such reductions shall be treated as an After-Tax Contribution. To the extent such amount cannot be treated as an After-Tax Contribution because of the limitation described in the preceding sentence, such amount, plus any income and minus any loss allocable thereto through the end of the Plan Year for which the After-Tax Contribution was made, shall be distributed to such Participant no later than the last day of the subsequent Plan Year and the Participant shall forfeit any corresponding Employer Matching Contributions related thereto plus any income and minus any loss allocable thereto through the end of the Plan Year for which the Employer Matching Contribution was made. The Participant shall designate the extent to which such distributed excess contributions are treated as Untaxed Contributions or Designated Roth Contributions (but only up to the extent that such types of contributions were made by the Participant to the Plan for the Plan Year) and, in the event that any such designation is not made or is incomplete, such distributed excess contributions shall be treated as Untaxed Contributions up to the extent Untaxed Contributions were made to the Plan for the Plan Year and, to the extent that such distributed excess contributions exceed such Untaxed Contributions, such excess contributions shall be treated as distributions of Designated Roth Contributions made to the Plan for the Plan Year.

The amount of Before-Tax Contributions to be distributed to a Participant pursuant to this Section shall be reduced by any Before-Tax Contributions previously distributed to such Participant pursuant to Section 4.2(b) (relating to correction of Excess Before-Tax Contributions) for such Plan Year. The amount of any income or loss allocable to any such reductions to be so distributed shall be determined pursuant to Regulations. The unadjusted amount of any such reductions so distributed shall be treated as "annual additions" for purposes of Section 7.4 (relating to limitations on allocations imposed by section 415 of the Code).

(2) Adjustments to Comply with Section 401(m) of the Code . The Administrator shall cause to be made such periodic computations as it shall deem necessary or appropriate to determine whether either of the tests set forth in paragraph (b)(1) or (b)(2) of this Section 4.4 shall be satisfied during a Plan Year, and, if it appears to the Administrator that neither of such tests will be satisfied, the Administrator shall take such steps as it deems necessary or appropriate to adjust the Employer Matching Contributions made, After-Tax Contributions made, and any Before-Tax Contributions treated as Employer Matching Contributions pursuant to paragraph (d)(2) of this Section 4.4 for all or a portion of such Plan Year on behalf of Participants who are highly compensated eligible employees to the extent necessary in order for one of such tests to be satisfied. If after the end of a Plan Year it is determined that regardless of any steps taken neither of the tests set forth in paragraph (b)(1) or (b)(2) of this Section 4.4 shall be satisfied with respect to such Plan Year, the Administrator shall calculate the total amount by which any such contributions on behalf of Participants who are highly compensated eligible employees must be reduced in order to satisfy either such test, in the manner prescribed by section 401(m)(6) of the Code (the "excess aggregate contributions amount"). The amount to be reduced with respect to Participants who are highly compensated eligible employees shall be determined by first reducing the After-Tax Contributions (including Before-Tax Contributions recharacterized as After-Tax Contributions pursuant to paragraph (e)(1) of this Section 4.4) and then by reducing the Employer Matching Contributions for each Participant whose actual dollar amount of such aggregate contributions for such Plan Year is highest until such reduced dollar amount equals the next highest dollar amount of such contributions for such Plan Year on behalf of any other highly compensated eligible employee, or until the total reduction equals the excess aggregate contributions amount. If further reductions are necessary, such contributions on behalf of each Participant who is a highly compensated eligible employee and whose actual dollar amount of such contributions is the highest (after the reduction described in the preceding sentence) shall be reduced in accordance with the preceding

sentence. Such reductions shall continue to be made to the extent necessary until the total reduction equals the excess aggregate contributions amount. If After-Tax Contributions are distributed pursuant to this paragraph (e)(2), any corresponding Employer Matching Contributions related thereto plus any income and minus any loss allocable through the end of the Plan Year for which the Employer Matching Contributions were made to which such Participant would be entitled under Section 8.3 (relating to distributions upon termination of employment) if such Participant had terminated employment on the last day of the Plan Year for which contributions were made (or earlier if any such Participant actually terminated employment at any earlier date) shall also be distributed with such After-Tax Contributions (and taken into account to determine whether further reductions are necessary), and any remaining amount of such corresponding Employer Matching Contributions plus any income and minus any loss allocable through the end of the Plan Year for which the Employer Matching Contributions were made shall be forfeited. If the reductions required by this subparagraph exceed the amount of After-Tax Contributions made or to be made by any Participant for such Plan Year and the amount of Employer Matching Contributions made or to be made on behalf of such Participant for such Plan Year, any Before-Tax Contributions made on behalf of such Participant that the Administrator has elected to treat as Employer Matching Contributions pursuant to paragraph (d)(2) of this Section 4.4 shall also be adjusted and taken into account in accordance with this subparagraph, except that such Before-Tax Contributions may not be recharacterized as After-Tax Contributions.

Section 4.5. Limitation on Employer Contributions.

The contributions of an Employer for any Plan Year shall not exceed the maximum amount for which a deduction is allowable to such Employer for federal income tax purposes for the fiscal year of such Employer that coincides with such Plan Year.

Any contribution made by an Employer by reason of a good faith mistake of fact, or the portion of any contribution made by an Employer that exceeds the maximum amount for which a deduction is allowable to such Employer for federal income tax purposes by reason of a good faith mistake in determining the maximum allowable deduction, shall upon the request of such Employer be returned by the Trustee to the Employer. An Employer's request and the return of any such contribution must be made within one year after such contribution was mistakenly made or after the deduction of such excess portion of such contribution was disallowed, as the case may be. The amount to be returned to an Employer pursuant to this paragraph shall be the excess of (i) the amount contributed over (ii) the amount that would have been contributed had there not been a mistake of fact or a mistake in determining the maximum allowable deduction. Earnings attributable to the mistaken contribution shall not be returned to the Employer, but losses attributable thereto shall reduce the amount to be so returned. If the return to the Employer of the amount attributable to the mistaken contribution would cause the balance of any Participant's account as of the date such amount is to be returned (determined as if such date coincided with the close of a Plan Year) to be reduced to less than what would have been the balance of such account as of such date had the mistaken amount not been contributed, the amount to be returned to the Employer shall be limited so as to avoid such reduction.

Any Before-Tax Contributions returned to an Employer pursuant to this Section 4.5 shall be treated as the return of Untaxed Contributions, up to the extent Untaxed Contributions were made by such Participant to the Plan for such Plan Year and, to the extent that the returned contributions exceed such Untaxed Contributions, such returned contributions shall be treated as Designated Roth Contributions made by the Participant to the Plan for the Plan Year.

ARTICLE 5

EMPLOYEE CONTRIBUTIONS

Section 5.1. After-Tax Contributions.

Subject to the limitations set forth in Section 4.4 (relating to limitations on contributions for highly-compensated Eligible Employees) and Section 7.4 (relating to limitations on allocations imposed by section 415 of the Code), each Participant who is an Eligible Employee may elect in accordance with Section 3.2(a) to make After-Tax Contributions under the Plan by payroll deduction. After-Tax Contributions made by a Participant who is a member of a bargaining unit represented by IBEW Local Union 15 for any payroll period shall equal a whole percentage not less than 1 nor more than 10 percent of the Participant's Compensation for such payroll period, as designated by the Participant in his or her request pursuant to Section 3.2(a). After-Tax Contributions made by any other Participant for any payroll period shall equal a whole percentage not less than 1 nor more than 20 percent and, effective as of January 1, 2006, 50 percent, of the Participant's Compensation for such payroll period, as designated by the Participant in his or her request pursuant to Section 3.2(a). Except as set forth below, After-Tax Contributions shall be delivered to the Trustee no less frequently than bi-weekly. In addition, if back-pay is awarded to a Participant who is an Eligible Employee and any portion of such back-pay constitutes Compensation as defined in subsection (13) of Article 2 (relating to the definition of compensation), After-Tax Contributions shall be made for such Participant in an amount equal to the After-Tax Contribution percentage, which was most recently chosen by the Participant in his or her request pursuant to Section 3.2(a), of such back-pay that constitutes Compensation. An

After-Tax Contribution described in the preceding sentence shall be treated under the Plan in the same manner as all other After-Tax Contributions and shall be delivered to the Trustee as soon as practicable after the back-pay is paid to the Participant. Except as provided in the following sentence and in Section 4.1, After-Tax Contributions shall be subject to the same provisions regarding commencement, change and suspension applicable to Before-Tax Contributions as set forth in Section 4.1. If a Participant who has not attained age 59 ½ makes a withdrawal of After-Tax Contributions pursuant to Section 8.1(c), then: (a) After-Tax Contributions made by such Participant pursuant to this Section 5.1 shall cease beginning with the first payroll period beginning after the date on which the Participant receives such withdrawal and (b) such Participant shall not again be eligible to elect such contributions until the first payroll period that coincides with or follows the date on which contributions ceased by 6 months.

Section 5.2. Rollover Contributions.

(a) The Trustee shall be authorized to receive, hold and distribute in accordance with the Plan, a direct rollover contribution consisting of cash, transferred to the Plan by (i) a qualified plan described in section 401(a) or 403(a) of the Code, including after-tax employee contributions to such plan, (ii) an annuity contract described in section 403(b) of the Code, excluding after-tax employee contributions or (iii) an eligible plan under section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state. The Trustee shall also be authorized to receive, hold and distribute in accordance with the Plan, a Participant contribution of an eligible rollover distribution from (A) a qualified plan described in section 401(a) or 403(a) of the Code, (B) an annuity contract described in section 403(b) of the Code, (C) an eligible plan under section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state or (D) an individual retirement account or annuity described in section 408(a) or 408(b) of the Code that is eligible to be rolled over and would otherwise be includible in gross income. The amounts transferred must be eligible rollover distributions, as defined in section 402(c) of the Code. Effective December 1, 2012, an eligible rollover distribution of a lump sum amount from a qualified defined benefit plan sponsored by the Company also may be contributed to this Plan in accordance with administrative rules established by the Administrator. Notwithstanding any provision of the Plan to the contrary, a rollover contribution shall not include "designated Roth contributions" described in section 402A of the Code or any related earnings with respect to such contributions.

(b) Delivery of Rollover Contributions to Administrator . Except as otherwise provided in paragraph (a) of this Section 5.2, if an individual desires to make a rollover contribution pursuant to such paragraph (a), such contribution either (i) shall be delivered by the individual to the Administrator and by the Administrator to the Trustee on or before the 60th day after the day on which the Employee receives the distribution or on or before such later date as may be prescribed by law, or (ii) shall be transferred on behalf of the individual directly from the trust from which the eligible rollover distribution is made. Any contribution that is delivered by the Eligible Employee must be accompanied by (i) a statement of the Employee that to the best of his or her knowledge the amount so transferred meets the conditions specified in paragraph (a) of this Section 5.2, (ii) a copy of such documents as may have been received by the Employee advising him or her of the amount of and the character of such distribution and (iii) any investment election with respect to such contribution in such form and manner as may be required by the Administrator. Notwithstanding the foregoing, the Administrator shall not accept a rollover contribution if in its judgment accepting such contribution would cause the Plan to violate any provision of the Code or Regulations, and the Administrator shall not be required to accept such a contribution to the extent it consists of property other than cash.

Section 5.3. Special Accounting Rules for Rollover Contributions .

If a rollover contribution is made by or on behalf of an Employee, the Administrator shall cause a Rollover Account to be established and maintained for such Employee to which shall be credited all rollover contributions made pursuant to Section 5.2. A rollover contribution shall be credited to such Rollover Account as of the Valuation Date coinciding with or next following the date on which such contribution is delivered to the Trustee.

If a rollover contribution is made by, or a direct transfer is made on behalf of, an Eligible Employee prior to becoming a Participant, such Eligible Employee shall until such time as he or she becomes a Participant be deemed to be a Participant, and his or her Rollover Account and After-Tax Contributions Account, if any, shall be deemed to be an account of a Participant, for all purposes of the Plan except for the purposes of the allocation of contributions provided for in paragraphs (a), (b), (c), (d) and (e) of Section 7.3 and any determination of when he or she becomes a Participant pursuant to Article 3.

ARTICLE 6

TRUST AND INVESTMENT FUNDS

Section 6.1. Trust.

A Trust shall be created by the execution of a trust agreement between the Company and the Trustee. All contributions under the Plan shall be paid to the Trustee. The Trustee shall hold all monies and other property received by it and invest and reinvest the same, together with the income therefrom, on behalf of the Participants collectively in accordance with the provisions of the trust agreement. The Trustee shall make distributions from the Trust Fund at such time or times to such person or persons and in such amounts as the Administrator directs in accordance with the Plan.

Section 6.2. Investment Funds.

The Trustee shall establish and maintain, or shall cause to be established and maintained, an investment fund herein called the "Employer Stock Fund" which shall be invested in Common Stock, and shall also include such short-term obligations and short-term liquid investments purchased by the Trustee, in accordance with the Trust Agreement, pending the selection and purchase of the Common Stock or as otherwise determined by the Trustee to be necessary to satisfy such fund's cash needs. In addition, as directed by the Investment Office, one or more additional separate investment funds shall be established and maintained and shall be invested as directed by the Investment Office. The Investment Office also may, from time to time, and in its sole discretion, segregate any of the assets held under any investment fund established pursuant to this Section 6.2 and allocate the investment results from such segregated assets among all or a portion of the accounts of Participants in such manner as it shall determine to be appropriate. All charges and expenses incurred in connection with the purchase and sale of investments for a fund shall be charged to such fund except to the extent such charges and expenses are paid by the Employers or from other revenue available to the Plan.

ARTICLE 7

PARTICIPANT ACCOUNTS AND INVESTMENT ELECTIONS

Section 7.1. Participant Accounts and Investment Elections.

(a) Participant Accounts. For each Participant the Administrator shall establish and maintain, or shall cause to be established and maintained, investment accounts to which amounts contributed under the Plan shall be credited according to each Participant's investment elections pursuant to paragraph (b) of this Section 7.1, subject to the penultimate sentence of the first paragraph of Section 6.2 (relating to the Investment Office's authority to segregate any of the assets held under any investment fund).

Each such investment account shall, to the extent appropriate, be composed of the following accounts: (A) a Before-Tax Contributions Account, which shall be divided into an Untaxed Contribution Account and a Designated Roth Contributions Account, (B) a Catch-Up Contributions Account, (C) an Employer Matching Contributions Account, (D) an After-Tax Contributions Account, and (E) a Rollover Account. Earnings and losses on investment of funds in each account shall be credited or debited to that account.

All such accounts and subaccounts shall be for accounting purposes only, and there shall be no segregation of assets within the investment funds among the separate Participants' accounts.

(b) Investment Election. Each Participant, as part of his or her request for participation described in Section 3.2 (or in connection with the delivery of a rollover contribution pursuant to Section 5.2), shall make an investment election that shall apply to the investment of contributions to be made on his or her behalf or by him or her pursuant to Article 4 (relating to Employer contributions) or Article 5 (relating to Employee contributions) and any earnings on such contributions. Such election shall specify that such contributions be invested either (i) wholly in one of the funds maintained or employed by the Trustee pursuant to paragraph (a) of this Section 7.1 or (ii) divided among such funds in 1 percent increments or in such other increments established by the Administrator or the Investment Office from time to time. Each Eligible Employee for whom a Rollover Account is established before such Eligible Employee has become a Participant shall, in the manner prescribed by the Administrator, make such investment election as of the Valuation Date on which such account is established. During any period in which no direction as to the investment of an Employee's account is on file with the Administrator, contributions or direct transfers made by him or her, or on his or her behalf, to the Plan will be invested in such manner as the Investment Office shall determine.

(c) Change of Investment Election. Subject to such restrictions as may be imposed by the Administrator or the Investment Office (including, without limitation, any restrictions imposed with respect to transfers of funds to or from the Employer Stock Fund described in Section 6.2 by individuals who are subject to Rule16b-3 under section 16 of the Securities Exchange Act of 1934), a Participant may elect to change as of any Valuation Date his or her investment election applicable to all or any portion of his or her current account balance. In addition, a Participant may elect to change as of the first day of any payroll period his or her investment election applicable to future contributions made pursuant to Articles 4 (relating to Employer contributions) or 5 (relating to Employee contributions), or both, as specified by the Participant. Such changes shall be limited to the investment funds then maintained or employed by the Trustee pursuant to paragraph (a) of this Section 7.1. A Participant's change of investment election must be made in the manner and at the time prescribed by the Administrator (or its delegate). Any such change shall specify that such contributions be invested either (i) wholly in one of the funds maintained or employed by the Trustee pursuant to paragraph (a) of this Section 7.1, or (ii) divided among such funds in 1 percent increments or such other increments established by the Administrator or the Investment Office from time to time.

Section 7.2. Allocation of Net Income of Trust Fund and Fluctuation in Value of Trust Fund Assets.

In the event that contributions, income and losses are not otherwise specifically allocated to Participant accounts by the Trustee, as soon as practical after each Valuation Date, the net worth of each investment fund (as defined in Section 6.2) as of such Valuation Date shall be determined. If the net worth of such investment fund as so determined is more or less than the total of all balances credited as of such Valuation Date to the subaccounts of Participants invested in the investment fund as of such Valuation Date who are Participants as of such Valuation Date, the amount of any excess or deficiency shall be prorated and credited or charged to such subaccounts proportionally to the balances of such subaccounts as of the preceding Valuation Date after making all allocations for such preceding Valuation Date prescribed by this Article and after decreasing each such subaccount by any loans, withdrawals or distributions from such subaccount during such period (but not less than zero), with all of such decreases to be made in such manner as the Administrator determines in its discretion to be necessary.

Notwithstanding any provision of this Article 7, any Designated Roth Contributions Account shall be maintained in a manner that satisfies the separate accounting requirement, and any Regulations or other requirements promulgated, under section 402A of the Code. Accordingly, gains, losses and other credits and charges shall be separately allocated on a reasonable basis to each such account and other accounts under the Plan, the Plan shall keep a record of each Participant's Designated Roth Contributions that have not been withdrawn, and contributions and withdrawals of Designated Roth Contributions, and related earnings, shall be accounted for with respect to Designated Roth Contributions Accounts. However, forfeitures shall not be allocated to any Designated Roth Contributions Account. These separate accounting requirements apply with respect to a Participant from the time the Participant makes his or her first Designated Roth Contribution until the time the Participant's Designated Roth Contributions Account is distributed.

Section 7.3. Allocations of Contributions Among Participants' Accounts .

(a) Allocation of Before-Tax Contributions. Before-Tax Contributions shall be allocated to the Before-Tax Contributions Account of each Participant for whom such contributions are made as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract. The Before-Tax Contributions that consist of (i) Before-Tax Contributions made on behalf of the Participant pursuant to Section 4.1 for Plan Years beginning prior to (A) in the case of a Participant who is not a Local 15 Member, January 1, 2006, and (B) in the case of a Participant who is a Local 15 Member, January 1, 2009, (ii) any Before-Tax Contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant, and (iii) any Before-Tax Contributions that are Untaxed Contributions made pursuant to Section 4.2 for Plan Years beginning on or after (A) in the case of a Participant who is not a Local 15 Member, January 1, 2006, and (B) in the case of a Participant who is a Local 15 Member, January 1, 2009, shall be allocated to the Untaxed Contributions Account of such Participant. The Before-Tax Contributions that consist of Designated Roth Contributions made on behalf of the Participant pursuant to paragraph (c) Section 4.2 (relating to Untaxed Contributions and Designated Roth Contributions) for Plan Years beginning on or after (A) in the case of a Participant who is not a Local 15 Member, January 1, 2006, and (B) in the case of a Participant who is a Local 15 Member, January 1, 2009, January 1, 2006 shall be allocated to the Designated Roth Contributions Account of such Participant.

(b) Allocation of Catch-Up Contributions . Catch-Up Contributions shall be allocated to the Catch-Up Contributions Account of each Participant for whom such contributions are made as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract.

(c) Allocation of Employer Matching Contributions . Employer Matching Contributions shall be allocated to the Employer Matching Contributions Account of each Participant for whom such contributions are made as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract.

(d) Allocation of After-Tax Contributions. After-Tax Contributions shall be allocated to the After-Tax Contributions Account of the Participant who makes such contributions as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract.

(e) Allocation of Rollover Contributions and Direct Transfers. Rollover contributions made pursuant to Article 5 (relating to Employee contributions) shall be credited to the Rollover Account of the Participant on whose behalf such contribution is made as of the Valuation Date coinciding with or next following the date on which the contribution is delivered to the Trustee.

(f) Allocation of Forfeitures. The total amount forfeited during any Plan Year shall be used to (i) pay the expenses incurred by the Trustee for the administration of the Trust Fund not paid by the Company, (ii) held to pay the expenses reasonably estimated by the Trustee for the administration of the Trust Fund during the next following Plan Year but not expected to be paid by the Company, or (iii) used to reduce Employer Matching Contributions as determined by the Administrator.

Section 7.4. Limitations on Allocations Imposed by Section 415 of the Code.

Notwithstanding any other provision of the Plan, the amount allocated to a Participant's accounts under the Plan for each Plan Year shall be limited so that the aggregate annual additions to the Participant's accounts under this Plan and in all other defined contribution plans maintained by an Employer shall not exceed the lesser of: (A) $46,000 (as adjusted pursuant to section 415(d) of the Code) and (B) 100% of the Participant's compensation for such Plan Year.

If the amount to be allocated to a Participant's accounts pursuant to Section 7.3 (relating to allocations of contributions among Participant's accounts) for a Plan Year would exceed the limitation set forth in this Section 7.4, then such excess shall be reduced before allocations are made to the Participant's accounts. If, in any Plan Year, the annual additions actually allocated to the Participant's accounts exceed the limitation set forth in this Section 7.4, then such annual additions shall be corrected in accordance with the Employee Plans Compliance Resolution System of the Internal Revenue Service.

For purposes of this Section 7.4, the “annual additions” for a Plan Year to a Participant’s accounts in this Plan and in any other defined contribution plan maintained by an Employer is the sum during such Plan Year of:

(a) the amount of Employer contributions (including Before-Tax Contributions and Designated Roth Contributions and excluding any Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2) allocated to the Participant’s accounts, excluding, however, (X) Before-Tax Contributions and Designated Roth Contributions that are “catch-up contributions” made pursuant to section 414(v) of the Code, (Y) excess deferrals that are distributed in accordance with section 402(g) of the Code and (Z) restorative payments (within the meaning of section 1.415(c)-1(b)(2)(ii)(C) of the Regulations),

(b) the amount of forfeitures allocated to the Participant’s accounts,

(c) the amount of Employee contributions allocated to the Participant accounts, but excluding any rollover contributions, direct transfers or loan repayments, and

(d) the contributions allocated on behalf of the Participant to any individual medical benefit account (as defined in section 415(l) of the Code) or, if the Participant is a key employee within the meaning of section 419A(d)(3) of the Code, to any post-retirement medical benefits account established pursuant to section 419A(d)(1) of the Code.

For purposes of this Section 7.4, “defined contribution plan” shall have the meaning set forth in section 415 of the Code and Regulations, and the term “Employer” shall include all Affiliates except that in defining Affiliates “more than 50 percent” shall be substituted for “at least 80 percent” where required by section 415(g) of the Code. In addition, for purposes of this Section 7.4, “compensation” shall mean a Participant’s compensation as defined under section 415(c)(3) of the Code (as amended from time to time).

Section 7.5. Correction of Error.

If it comes to the attention of the Administrator that an error has been made in any of the allocations prescribed by this Article or an error has been made in any other respect, appropriate adjustment shall be made to the accounts of all Participants and designated Beneficiaries that are affected by such error, except that no adjustment need be made with respect to any Participant or Beneficiary whose account has been distributed in full prior to the discovery of such error.

ARTICLE 8

WITHDRAWALS AND DISTRIBUTIONS

Section 8.1. Withdrawals and Distributions Prior to Termination of Employment.

(a) Hardship Withdrawals. An Employee who has not attained age 59 ½ may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, to withdraw as of any date all or a portion of the balance of his or her Before-Tax Contributions Account (other than earnings credited to such account after December 31, 1988), Catch-Up Contributions Account and Employer Matching Contributions Account only if the Participant has incurred a financial hardship, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal under this paragraph (a) shall be the balance in such account less the balance of all outstanding loans to the Participant. The determination of the existence of financial hardship and the amount required to be distributed to satisfy the need created by the hardship will be made by the Administrator in a uniform and non-discriminatory manner subject to the following rules:

(A) A financial hardship shall be deemed to exist if, and only if, the Participant certifies to the Committee that the financial need is on account of:

(i) medical expenses described in section 213(d) of the Code incurred or anticipated to be incurred by the Participant, the Participant's Spouse or any dependents of the Participant (as defined in section 152 of the Code) or primary beneficiary;

(ii) funeral or burial expenses incurred by the Participant for the Participant's deceased parent, Spouse, children or dependent (as defined in section 152 of the Code, without regard to section 152(d)(1)(B) of the Code) or primary beneficiary;

(iii) the purchase (excluding mortgage payments) of a principal residence of the Participant;

(iv) the payment of tuition, related educational fees, and room and board expenses for up to the next twelve months of post-secondary education for the Participant, the Participant's Spouse, children or dependents (as defined in section 152 of the Code, without regard to sections 152(b)(1) and (2) and 152(d)(1)(B) of the Code) or primary beneficiary;

(v) the need to prevent eviction of the Participant from his or her principal residence or foreclosure of mortgage of the Participant's principal residence; or

(vi) expenses for the repair of damage to the Participant's principal residence that would qualify for the casualty deduction under section 165 of the Code (determined without regard to whether the loss exceeds 10% of adjusted gross income).

For purposes of the foregoing, an individual is a Participant's "primary beneficiary" if the Participant has designated him or her as a "Beneficiary" under Section 8.5 and such individual has an unconditional right to all or a portion of the Participant's accounts upon the Participant's death.

(B) A distribution shall be deemed to be necessary to satisfy a financial need of the Participant if, and only if, the Participant:

(i) has obtained all distributions, other than hardship withdrawals, and all nontaxable loans under any Employer's plan in which the Participant participates, and

(ii) demonstrates to the satisfaction of the Administrator that the distribution is not in excess of the amount of the immediate and heavy financial need, which need shall include amounts necessary to pay any federal, state and local income taxes, excise taxes and penalties.

If a Participant receives a hardship withdrawal pursuant to this paragraph (a), then, in addition to the cessation of Before-Tax Contributions and After-Tax Contributions required by paragraph (a) of Section 4.1 (relating to initial election regarding regular payroll Before-Tax Contributions), contributions by the Participant to qualified or nonqualified plans of deferred compensation, including a stock option, stock purchase or similar plan, maintained by an Employer also shall (except where excused by regulation) cease beginning with the first payroll period beginning after the date on which the Participant receives such hardship withdrawal and continuing until the first payroll period that coincides with or follows the date on which contributions ceased by six months.

The Participant shall designate the extent to which the hardship withdrawal pursuant to this paragraph (a) are Designated Roth Contributions from the Participant's Designated Roth Contributions Account and the extent that such withdrawals are Untaxed Contributions from the Participant Untaxed Contributions Account and in the event that any such designation is not made or is incomplete, such hardship withdrawals shall be treated as withdrawals of Designated Roth Contributions to the extent Designated Roth Contributions were made to the Plan and, to the extent that the hardship withdrawal exceeds such Designated Roth Contributions, such hardship withdrawal shall be treated as Untaxed Contributions.

(b) Withdrawals After Age 59 ½. An Employee who has attained age 59 ½ may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, to withdraw as of any date an amount which is not greater than the balance of his or her Before-Tax Contributions Account, Catch-Up Contributions Account and Employer Matching Contributions Account as of the most recent Valuation Date determined by the Administrator, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal shall be the balance in such accounts less the balance of all outstanding loans to the Participant.

The Participant shall designate the extent to which the withdrawal pursuant to this paragraph (b) are Designated Roth Contributions from the Participant's Designated Roth Contributions Account and the extent that such withdrawals are Untaxed Contributions from the Participant's Untaxed Contributions Account and in the event that any such designation is not made or is incomplete, such withdrawals shall be treated as withdrawals of Designated Roth Contributions to the extent Designated Roth Contributions were made to the Plan and, to the extent that the withdrawal exceeds such Designated Roth Contributions, such withdrawal shall be treated as Untaxed Contributions.

(c) Withdrawals From the After-Tax Contributions Account. An Employee may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, no more than once during any Plan Year, to withdraw from his or her After-Tax Contributions Account an amount which is not greater than the balance of the Participant's After-Tax Contributions Account as of the most recent Valuation Date determined by the Administrator, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal shall be the balance in such account less the balance of all outstanding loans to the Participant.

(d) Withdrawals from the Rollover Account. A Participant may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, to withdraw an amount which is not greater than the balance in his or her Rollover Account as of the most recent Valuation Date determined by the Administrator, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal shall be the balance in such account less the balance of all outstanding loans to the Participant.

(e) Qualified Reservist Withdrawals. A Participant who is a Qualified Reservist may make a request by calling VRU, or in such manner as may be prescribed by the Administrator, to withdraw any portion of his or her Before-Tax Contributions Account or his or her Designated Roth Contributions Account, and the amount requested shall not be subject to the 10 percent additional tax imposed pursuant to section 72(t)(2)(G) of the Code, provided that the amount requested is distributed during the period beginning on the date the Participant is ordered or called to active duty and ending at the close of his or her active duty.

(f) Withdrawals of Employer Matching Contributions for Members of IBEW Local Union 614 . Notwithstanding any provision in the Plan to the contrary, effective April 16, 2010, a Participant who is a member of a bargaining unit represented by IBEW Local Union 614 and who has completed 60 months as a Participant may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of his or her Employer Matching Contributions Account, as adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution.

Additionally, effective April 16, 2010, a Participant who is a member of a bargaining unit represented by IBEW Local Union 614, regardless of whether he or she has completed 60 months as a Participant, may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of that portion of the Employer Matching Contributions Account that is derived from Employer Matching Contributions in excess of Employer Matching Contributions allocated to his or her Employer Matching Contributions Account during the two Plan Years preceding the Plan Year in which the withdrawal takes place, adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution.

No distribution made pursuant to this paragraph (f) may be for an amount which is less than the lesser of (i) $200; and (ii) the balance of the Participant's Employer Matching Contributions Account, as adjusted for gains, earnings and losses attributable thereto. In addition, a Participant may not make more than one withdrawal pursuant to this paragraph (f) in any Plan Year.

(g) Provisions Applicable to All Withdrawals. Any withdrawal made pursuant to this Section 8.1 shall be made at such time as prescribed by the Administrator and shall be made pro-rata from each of the investment funds in which as of the date of the withdrawal (i) in the case of a withdrawal pursuant to paragraph (a) or (b) of this Section 8.1, the Participant's Before-Tax Contributions Account, Catch-Up Contributions Account (and, if applicable, Employer Matching Contributions Account) is invested, (ii) in the case of a withdrawal pursuant to paragraph (c) of this Section 8.1, the Participant's After-Tax Contributions Account is invested, (iii) in the case of a withdrawal pursuant to paragraph (d) of this Section 8.1, the Participant's Rollover Account is invested, (iv) in the case of a withdrawal pursuant to paragraph (e) of this Section 8.1, the Participant's Before Tax Contributions Account and Designated Roth Contributions Account, and (v) the case of a withdrawal pursuant to paragraph (f) of this Section 8.1, the Participant's Employer Matching Contribution Account. Notwithstanding anything in the Plan to the contrary, the Administrator or the Investment Office may impose any restrictions it deems necessary or appropriate with respect to withdrawals by individuals who have any portion of their accounts invested in the Employer Stock Fund described in Section 6.2 and who are subject to Rule 16b-3 under section 16 of the Securities Exchange Act of 1934.

(h) Dividend Distributions in Respect of the Employer Stock Fund . Dividends shall be allocated to the accounts of each Participant, any portion of whose account balance is invested in the Employer Stock Fund in accordance with paragraph (b) of Section 7.1, based upon the total number of shares of Common Stock represented by the Participant's proportionate share of the Employer Stock Fund as of such date as may be determined from time to time by the Administrator on or before each dividend record date. Cash dividends shall be reinvested in Common Stock (through the Employer Stock Fund) unless the Participant (or his or her Beneficiary) elects, at the time and in the manner prescribed by the Administrator, to receive a cash distribution in an amount equal to such dividend, payable not later than 90 days after the end of the Plan Year in which such dividend was paid.

Section 8.2. Loans to Participants.

(a) Making of Loans. Subject to the restrictions set forth in this Section 8.2, the Administrator shall establish a loan program whereby any Participant who is a party-in-interest (within the meaning of section 3(14) of ERISA) or any Beneficiary who is a party-in-interest and any such Participant's Beneficiary may request, in the manner and form prescribed by the Administrator, to borrow funds from the Plan. The principal amount of such loan shall be not less than $1,000 and the aggregate amount of all outstanding loans to a Participant or Beneficiary shall not exceed the lesser of: (1) 50% of the value of the aggregate of the Participant's vested account balances as of the Valuation Date coinciding with or immediately preceding the day on which the loan is made; and (2) $50,000, reduced by the excess, if any, of the highest outstanding loan balances of the Participant under all plans maintained by the Employer during the period of time beginning one year and one day prior to the date such loan is to be made and ending on the date such loan is to be made over the outstanding balance of loans from all such plans on the date on which such loan was made.

(b) Restrictions. Any loan approved by the Administrator pursuant to the preceding paragraph (a) shall be made only upon the following terms and conditions:

(1) The period for repayment of the loan shall be arrived at by mutual agreement between the Administrator and the Participant but such period shall not exceed five years or, in the case of a loan to acquire a principal place of residence, shall not be less than five years or more than 15 years, from the date of the loan. Such loan may be prepaid at any time, without penalty, by delivery to the Administrator of a check in an amount equal to the entire unpaid balance of such loan. No partial prepayment shall be permitted. Except as otherwise provided under uniform and nondiscriminatory procedures established by the Administrator, any loan to a Participant who is an Employee is due in full immediately after termination of employment.

(2) No loan shall be made to a Participant who is an Employee unless such Participant consents to have such loan repaid in substantially equal installments deducted from the regular payments of the Participant's compensation during the term of the loan. A Participant who (a) was an Employee at the time the Participant received a loan from the Plan, (b) is no longer an Employee and no longer receives compensation from an Employer, but (c) continues to perform services for an Employer, shall consent, either at the time the loan is taken or prior to the date prescribed by the Administrator, to have the balance of any loan outstanding at the time the Participant no longer is an Employee repaid in substantially equal installments over the remaining life of the loan. Such installments shall be paid in the manner specified by the Administrator.

(3) Each loan shall be evidenced by the Participant's collateral promissory note, in the form prescribed by the Administrator, for the amount of the loan, with interest, payable to the order of the Plan, and shall be secured by an assignment of 50% of the Participant's vested account balance.

(4) Each loan shall bear a fixed interest rate commensurate with the interest rates then being charged by persons in the business of lending money for loans made under similar circumstances, as determined by the Administrator.

(5) Except as otherwise provided in this Plan, no withdrawal (other than a withdrawal from a Participant's accounts to the extent that such withdrawal would not reduce the Participant's vested account balances to less than the then outstanding balance of any loan to such Participant or such higher amount determined by the Administrator to be appropriate security for such loan) or distribution shall be made to any Participant who has borrowed from the Trust, or to a Beneficiary of any such Participant, unless and until the loan, including interest, has been repaid.

(6) A charge shall be made against the account of each Participant requesting a loan equal to such reasonable loan application fee (and loan acceptance fee, if required by the Administrator) as shall be set from time to time by the Administrator.

(7) A Participant is permitted only one loan in any calendar year, provided, however, that no more than five loans to a Participant may be outstanding at any time, except that for a Participant described in the following sentence, no more than three loans may be outstanding at any time (for the period beginning April 1, 2009 and ending August 31, 2010, only one of such outstanding loans may be for the purpose of acquiring a principal place of residence and only two of such outstanding loans may be for other

purposes). A Participant described in the preceding sentence is any of the following: (A) a Participant who is a member of a bargaining unit represented by IBEW Local Union 15, (B) a Participant who is employed at Byron in Nuclear Security and is a member of United Security System Union Local 1, (C) a Participant who is employed at Oyster Creek in Nuclear Security and is a member of United Government Security Officers of America Local 17, (D) a Participant who is employed at Three Mile Island in Nuclear Security in Nuclear Security and is a member of United Government Security Officers of America Local 18, and (E) a Participant who is classified by an Employer as a management employee.

(8) Loan repayments shall be invested in the various investment funds as elected by the Participant.

(9) The Administrator may, in its sole discretion, restrict the amount to be disbursed pursuant to any loan request to the extent it deems necessary to take into account any fluctuations in the value of a Participant's accounts since the Valuation Date immediately preceding the date on which such loan is to be made.

(10) Any restrictions the Administrator or the Investment Office determines are necessary or appropriate with respect to loans requested by individuals who have any portion of their accounts invested in the Employer Stock Fund described in Section 6.2 and who are subject to Rule 16b-3 under section 16 of the Securities Exchange Act of 1934.

If any loan or portion of a loan made to a Participant under the Plan, together with the accrued interest thereon, is in default (taking into account any grace period permitted by law, and as determined by the Administrator), the Administrator shall take appropriate steps to collect on the note and foreclose on the security. If upon a Participant's termination of employment entitling the Participant to a distribution under Section 8.3 (relating to distributions upon termination of employment), death or retirement, any loan or portion of a loan made to such Participant under the Plan, together with the accrued interest thereon, remains unpaid, such unpaid amount may be repaid to the Plan no later than the last day of the calendar quarter following the calendar quarter in which such termination of employment occurred or as of such later date or dates permitted under uniform and nondiscriminatory procedures established by the Administrator. If full repayment is not so made, an amount equal to the unpaid portion of such loan, together with the accrued interest thereon, shall be charged to the Participant's accounts after all other adjustments required under the Plan, but before any distribution pursuant to Section 8.3 (relating to distributions upon termination of employment).

(c) Loan Subaccount. The Trustee shall establish and maintain a loan subaccount on behalf of each Participant or Beneficiary to whom a loan is made under this Section 8.2. Such subaccount shall represent the investment of the Participant's or Beneficiary's account in such loan. As of the Valuation Date immediately preceding the date on which a loan is approved, the Participant's or Beneficiary's loan subaccount shall be credited with the amount of the loan and thereafter shall be debited with repayments of the principal of such loan. The various accounts maintained for the Participant or Beneficiary shall be invested in the loan subaccount and debited by the amount of the loan and credited with payments of interest on, and repayments of principal of, such loan in accordance with uniform rules established by the Administrator.

(d) Sarbanes-Oxley. Notwithstanding any provision of the Plan to the contrary, the Administrator reserves the right to deny the request of a Participant for a loan that, in the judgment of the Administrator, would violate any provision of the Sarbanes-Oxley Act of 2002.

Section 8.3. Distributions Upon Termination of Employment.

(a) Termination of Employment under Circumstances Entitling Participant to Full Distribution of His or Her Account Balance . If a Participant terminates employment, the Participant, or his or her designated Beneficiary, as the case may be, shall be entitled to receive the entire balance of the Participant's accounts, at the time set forth in Section 8.4 (relating to time of distribution) and in the manner set forth in paragraph (b) of this Section 8.3.

(b) Form of Distribution. (1) Subject to paragraph (d) of this Section 8.3 (relating to small benefits payable in lump sum), any distribution to which a Participant or Beneficiary, as the case may be, becomes entitled upon termination of employment shall be distributed by whichever of the following forms of distribution the Participant or Beneficiary, as the case may be, elects by calling the VRU, or in such other manner as may be prescribed by the Administrator:

(A) By payment in a lump sum.

(B) By payment in a series of approximately equal annual, quarterly, or monthly installments, over a period of up to 15 years; provided that installments shall not be available with respect to amounts invested in the CNA 1997 guaranteed investment contract.

A Participant who elected to receive distribution of his or her vested account balance in the form of installments may, at any time after such election is made, elect to receive the remaining amount of his or her vested account balance in the form of a lump sum payment. If no election is made by a Participant or Beneficiary, as the case may be, as to the form of distribution, the Participant's vested account balance shall be distributed in the form of a lump sum payment.

The amount distributed hereunder shall be paid in cash, except that if the Participant's account is paid in a lump sum, then the Participant may request that all of his or her account invested in the Employer Stock Fund be distributed in whole shares of Common Stock held in such Fund with any fractional share being paid in cash. The number of shares of Common Stock to be distributed shall be based on the current fair market value of a share of Common Stock as determined by the Trustee under Section 7.2 (relating to allocation of net income of Trust Fund and fluctuation in value of Trust assets) as of the Valuation Date coinciding with or immediately preceding the date payment of the Participant's account is to be made. Requests for distribution in the form of Common Stock shall be made at such time and in such manner as the Administrator shall determine under rules and regulations which are uniformly applied.

Notwithstanding the preceding paragraphs, no distribution shall be made in the form of installments with respect to a Participant's Rollover Account that was established to hold the amount distributed or directly transferred from the Commonwealth Edison Company Employee Stock Ownership Plan upon such plan's termination if the Participant elected not to receive distribution of such amount until his or her 65th birthday.

(c) Notice of Availability of Election of Optional Forms of Benefits. No less than 30 days (or such shorter period as permitted by law) and no more than 90 days before distribution is to be made hereunder, the Administrator, or its designee, shall explain to the Participant that he or she may elect either form of distribution set forth in paragraph (b) of this Section 8.3. Such explanation shall include a general description of the eligibility conditions and other material features of the optional forms of distribution provided under the Plan. Notwithstanding the first sentence of this paragraph (c), distribution may commence less than 30 days after the description described above is given, provided that: (i) the Administrator, or its designee, clearly informs the Participant that the Participant has a right to a period of at least 30 days after receiving the explanation to consider the decision of whether or not to elect a distribution (and, if applicable, a particular distribution option), and (ii) the Participant, after receiving the explanation, affirmatively elects a distribution. The description referred to in this paragraph (c), as well as the explanation of the participant's right to a period of at least 30 days to consider such explanation before electing a distribution, shall be provided to the Participant through the VRU or in such other manner prescribed by the Administrator.

(d) Small Benefits Payable in Lump Sum. Notwithstanding any provision of the Plan to the contrary, if the vested amount of the Participant's account balances does not exceed $5,000, not including the value of the Participant's Rollover Account or, for distributions occurring on or after March 28, 2005, $1,000, including the value of the Participant's Rollover Account (such amount referred to herein as the "small benefit amount"), such vested amount shall be distributed in a lump sum cash payment as soon as administratively practicable after the Participant's termination of employment in accordance with such procedures as may be established by the Administrator.

(e) Direct Rollover Option. In the case of a distribution from the Plan (excluding any amount offset against the Participant's account balance to repay the outstanding balance of any unpaid loan) which is an "eligible rollover distribution" within the meaning of section 402(c)(4) of the Code, a Participant (or surviving Spouse of a Participant or a former Spouse who is an alternate payee under a qualified domestic relations order as defined in section 414(p) of the Code) may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from this Plan to (i) an individual retirement account described in section 408(a) of the Code, (ii) an individual retirement annuity described in section 408(b) of the Code, (iii) an annuity plan described in section 403(a) of the Code, (iv) an annuity contract described in section 403(b) of the Code, (v) a retirement plan qualified under section 401(a) of the Code (the terms of which permit the acceptance of rollover contributions), (vi) an eligible plan under section 457(b) of the Code which is maintained by an eligible employer described in section 457(e)(1)(A) of the Code (the terms of which permit the acceptance of rollover contributions) or (vii) effective January 1, 2008, a Roth IRA described in section 408A of the Code. However, in the case of a distribution of a Participant's After-Tax Contributions Account prior to January 1, 2007, such distribution shall only be directly transferred as a rollover contribution from this Plan to an account or annuity described in section 408 of the Code, or to such a retirement or annuity plan described in section 401(a) or 403(a) of the Code that is a defined contribution plan that agrees to separately account for amounts so transferred, including separately accounting for the portion of such amount which is includible in gross income and the portion of such distribution which is not so includible. In the case of a distribution of a Participant's After-Tax Contributions Account on or after January 1, 2007, such distribution shall only be directly transferred as a rollover contribution to an account or annuity described in section 408 of the Code, or to such a qualified retirement or annuity plan described in section 401(a) or 403(a) of the Code that agrees to separately account for amounts so transferred, including separately accounting for the portion of such amount which is includible in gross income and the portion of such distribution which is not so includible. Notwithstanding any provision of this paragraph (e), in the case of any eligible rollover distribution that includes all or any portion of the Participant's Designated Roth Contributions Account, a Participant or surviving Spouse or a former Spouse who is an alternate payee under a qualified domestic relations order as defined in section 414(p) of the Code may elect to transfer such portion only to another plan which accounts for Designated Roth Contributions described in section 402A of the Code or to a Roth IRA described in section 408A of the Code and only to the extent the rollover is permitted by the rules of section 402(c) of the Code. In addition, in the case of a distribution described in the preceding sentence that occurs on or after January 1, 2008, a Beneficiary who is not the surviving Spouse of the Participant may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from this Plan to (i) an individual retirement account described in section 408(a) of the Code, (ii) an individual retirement annuity described in section 408(b) of the Code or (iii) effective January 1, 2010, a Roth IRA described in section 408A of the Code, that, in either case, is established for the purpose of receiving such distribution on behalf of the Beneficiary.

Section 8.4. Time of Distribution.

A Participant who has terminated employment shall commence receiving distribution of his or her vested account balance as soon as administratively practical after the Valuation Date coinciding with or immediately following the date on which the Participant attains age 65, except as provided below.

(1) Early Distribution. Except as provided in subparagraph (7), a Participant whose Termination Date is prior to his or her 65th birthday may elect by calling the VRU, or in such other manner as may be prescribed by the Administrator, prior to his or her termination of employment to have distribution of his or her vested account balance commence within 60 days after the Valuation Date coinciding with or immediately following the Participant's Termination Date.

(2) Deferral of Distribution. A Participant may elect by calling the VRU, or in such other manner as may be prescribed by the Administrator, which election shall be made at the time prescribed by the Administrator, that distribution of his or her vested account balance commence as soon as practicable after the Participant's attainment of age 70 ½.

(3) Elections After Termination Date. Except as provided in subparagraph (7), a Participant who has terminated employment and whose distribution is to commence either after the Participant's attainment of age 65 or 70 ½ may elect at any time by calling the VRU, or in such other manner as may be prescribed by the Administrator, to have distribution of his or her vested account balance made within 60 days after the date such election is made.

(4) Required Beginning Date. Distributions paid or commencing during the Participant's lifetime shall commence not later than April 1 of the calendar year following the calendar year in which the Participant attains age 70 ½, except that distributions made to a Participant who is not a "five percent owner" (as defined in section 416(i) of the Code) may commence on April 1 of the calendar year following the later of the calendar year in which the Participant attains age 70 ½ or the calendar year in which the Participant retires. Notwithstanding any provision of the Plan to the contrary, any distributions required by this subparagraph shall be made not less rapidly than in accordance with the final Regulations under Section 401(a)(9). The Participant shall designate the extent to which the distribution of Before-Tax Contributions pursuant to this subparagraph 4 are Designated Roth Contributions from the Participant's Designated Roth Contributions Account and the extent that such withdrawals are Untaxed Contributions from the Participant's Untaxed Contributions Account and in the event that any such designation is not made or is incomplete, such distribution shall be treated as a distribution of Designated Roth Contributions to the extent Designated Roth Contributions were made to the Plan and, to the extent that the distribution of Before-Tax Contributions exceeds such Designated Roth Contributions, such distribution shall be treated as Untaxed Contributions.

(5) Distributions Commencing After Participant's Death. Distributions commencing after the Participant's death shall be completed within five years after the death of the Participant, except that (i) effective with respect to any Participant whose death occurs on or after January 1, 1995, regardless of when such Participant's employment terminated, if the Participant's Beneficiary is the Participant's Spouse, distribution may be deferred until the date on which the Participant would have attained age 70 ½ had he or she survived and (ii) if the Participant's Beneficiary is a natural person other than the Participant's Spouse and distributions commence not

later than one year after the Participant's death, such distributions may be made over a period not longer than the life expectancy of such Beneficiary. If at the time of the Participant's death, distribution of the Participant's benefit has commenced, the remaining portion of the Participant's benefit shall be paid in the manner elected by the Participant's Beneficiary, but at least as rapidly as was the method of distribution being used prior to the Participant's death.

(6) Distribution of Rollover Account After Termination Date. A Participant who has terminated employment or the Beneficiary of such Participant, as the case may be, may elect by calling the VRU, or in such other manner as may be prescribed by the Administrator prior to the time his or her vested account balance is distributed under this Section 8.4 to have distribution of the balance of his or her Rollover Account commence at such prior time as the Participant or Beneficiary shall elect, provided that, while any loan to the Participant under Section 8.2 remains outstanding, such distribution shall be made only to the extent that the balance of such Participant's vested account balance remaining after such distribution will equal or exceed the balance of all outstanding loans to the Participant.

(7) Compliance with Section 401(a)(9) of the Code. Notwithstanding any provision of the Plan to the contrary, all distributions will be made in accordance with section 401(a)(9) of the Code and the regulations promulgated thereunder, including the minimum distribution incidental death benefit requirement thereof. Notwithstanding the foregoing, any amount that would be a required minimum distribution described in section 401(a)(9) of the Code which is attributable to the 2009 calendar year will not be distributed to a Participant, or his or her Beneficiary, as applicable, unless such individual elects to receive such distribution. In addition, the five-year period described in subparagraph (5) above shall be determined without regard to calendar year 2009.

Notwithstanding anything contained herein to the contrary and except as provided in subparagraph (4) above, in the event that the recordkeeper for the Plan is changed, distributions may be made at such time as prescribed by the Administrator in order to accommodate the transfer of records to the new recordkeeper.

Section 8.5. Designation of Beneficiary.

Each Participant shall have the right to designate a Beneficiary or Beneficiaries (who may be designated contingently or successively and that may be an entity other than a natural person) to receive any distribution to be made under Section 8.3 (relating to distributions upon termination of employment) upon the death of such Participant or, in the case of a Participant who dies subsequent to termination of his or her employment but prior to the distribution of the entire amount to which he or she is entitled under the Plan, any undistributed balance to which such Participant would have been entitled, provided, however, that no such designation (or change thereof) shall be effective if the Participant was married on the date of the Participant's death unless such designation (or change thereof) was consented to at the time of such designation (or change thereof) by the person who was the Participant's Spouse, in writing, acknowledging the effect of such consent and witnessed by a notary public or a Plan representative, or it is established to the satisfaction of the Administrator that such consent could not be obtained because the Participant's Spouse cannot be located or such other circumstances as may be prescribed in Regulations. Subject to the preceding sentence, a Participant may from time to time, without the consent of any Beneficiary, change or cancel any such designation. Such designation and each change therein shall be made in the form prescribed by the Administrator and shall be filed with the Administrator. A Participant's beneficiary designation in effect under the PECO Energy Company Employee Savings Plan immediately prior to March 31, 2001 shall remain in effect under the Plan on and after March 31, 2001 until such time as such designation is changed or canceled in accordance with this Section 8.5. If (i) no Beneficiary has been named by a deceased Participant, (ii) such designation is not effective pursuant to the proviso contained in the first sentence of this section, or (iii) the designated Beneficiary has predeceased the Participant, any undistributed balance of the deceased Participant shall be distributed by the Trustee at the direction of the Administrator (a) to the surviving Spouse of such deceased Participant, if any, or (b) if there is no surviving Spouse, to the surviving children of such deceased Participant, if any, in equal shares, or (c) if there is no surviving Spouse or surviving children, to the surviving parents of such deceased Participant, if any, in equal shares, or (d) if there is no surviving Spouse, surviving children or surviving parents, to the executor or administrator of the estate of such deceased Participant or (e) if no executor or administrator has been appointed for the estate of such deceased Participant within six months following the date of the Participant's death, in equal shares to the person or persons who would be entitled under the intestate succession laws of the state of the Participant's domicile to receive the Participant's personal estate. The marriage of a Participant shall be deemed to revoke any prior designation of a Beneficiary made by him or her and a divorce shall be deemed to revoke any prior designation of the Participant's divorced Spouse if written evidence of such marriage or divorce is timely received by the Administrator.

Section 8.6. Distributions to Minor and Disabled Distributees.

Any distribution under this Article that is payable to a distributee who is a minor or to a distributee who, in the opinion of the Administrator, is unable to manage his or her affairs by reason of illness or mental incompetency may be made to or for the benefit of any such distributee at such time consistent with the provisions of Section 8.4 (relating to time of distribution) and in such of the following ways as the legal representative of such distributee shall direct: (a) directly to any such minor distributee if, in the opinion of such legal representative, the distributee is able to manage his or her affairs, (b) to such legal representative, (c) to a custodian under a Uniform Gifts to Minors Act for any such minor distributee, or (d) to some near relative of any such distributee to be used for the latter's benefit. Neither the Administrator nor the Trustee shall be required to see to the application by any third party other than the legal representative of a distributee of any distribution made to or for the benefit of such distributee pursuant to this Section.

Section 8.7. "Lost" Participants and Beneficiaries.

If within a period of five years following the death or other termination of employment of any Participant the Administrator in the exercise of reasonable diligence has been unable to locate the person or persons entitled to benefits under this Article 8, the rights of such person or persons shall be forfeited, provided, however, that the Plan shall reinstate and pay to such person or persons the amount of the benefits so forfeited upon a claim for such benefits made by such person or persons. The amount to be so reinstated shall be obtained from the total amount that shall have been forfeited pursuant to Section 8.3 (relating to distribution upon termination of employment) during the Plan Year that the claim for such forfeited benefit is made. If the amount to be reinstated exceeds the amount of such forfeitures, the Employer in respect of whose Employee the claim for forfeited benefit is made shall make a contribution in an amount equal to the remainder of such excess. Any such contribution shall be made without regard to whether or not the limitations set forth in Section 4.5 (relating to limitation on Employer contributions) will be exceeded by such contribution.

Section 8.8. Death Benefits Under USERRA

Effective January 1, 2007, in the case of a Participant who dies while performing Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any, (other than benefit accruals relating to the period of qualified military service) provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

ARTICLE 9

PARTICIPANTS' STOCKHOLDER RIGHTS

Section 9.1. Voting Shares of Common Stock.

Each Participant and Beneficiary shall be entitled to direct the Trustee as to the exercise of any voting rights attributable to shares of Common Stock then allocated to his or her account and the Trustee shall vote such shares according to the voting directions of the Participant or Beneficiary that have been timely submitted to the Trustee on forms provided by the Trustee for such purpose. Participants and Beneficiaries shall be permitted to direct the Trustee as to the exercise of any voting rights, including, but not limited to, any corporate matter that involves the voting of shares of Common Stock with respect to the approval or disapproval of any corporate merger or consolidation, recapitalization, reclassification, liquidation, dissolution, sale of substantially all assets of a trade or business, or similar transaction prescribed in Regulations. The Trustee shall with respect to any matter vote the shares of Common Stock credited to Participants' accounts with respect to which the Trustee does not timely receive voting instructions in the same proportion as to shares the Trustee has received voting instructions. Written notice of any meeting of stockholders of the Company and a request for voting instructions shall be given by the Administrator or the Trustee, at such time and in such manner as the Administrator shall determine, to each Participant or Beneficiary entitled to give instructions for voting shares of Common Stock at such meeting. The Administrator shall establish and pay for a means by which Participants and Beneficiaries can expeditiously deliver such voting instructions to the Trustee. All instructions delivered by Participants or Beneficiaries shall be confidential and shall not be disclosed to any person, including the Employer.

Section 9.2. Tender Offers.

(a) In the event a tender offer is made generally to the stockholders of the Company to transfer all or a portion of their shares of Common Stock in return for valuable consideration, including but not limited to, offers regulated by section 14(d) of the Securities Exchange Act of 1934, as amended, each Participant or Beneficiary shall be entitled to direct the Trustee regarding how to respond to any such tender offer with respect to the number of shares of Common Stock then allocated to his or her account and the Trustee shall vote such shares according to the voting directions of the Participant or Beneficiary that have been timely submitted to the Trustee on forms provided by the Trustee for such purpose. A Participant or Beneficiary shall not be limited in the number of directions to tender or withdraw from tender that he or she can give, but shall not have the right to give directions to tender or withdraw from tender after a reasonable time established by the Trustee pursuant to paragraph (c) of this Section 9.2. The Trustee shall with respect to a tender offer decline to vote the shares of Common Stock credited to Participants' accounts with respect to which the Trustee does not timely receive directions on how to respond to any such tender offer. All such directions shall be confidential and shall not be disclosed to any person, including the Employer.

(b) Within a reasonable time after the commencement of a tender offer, the Administrator shall provide to each Participant and Beneficiary:

(i) the offer to purchase as distributed by the offeror to the stockholders of the Company,

(ii) a statement of the shares of Common Stock allocated to his or her account, and

(iii) directions as to the means by which a Participant can give directions with respect to the tender offer.

The Administrator shall establish and pay for a means by which a Participant and Beneficiary can expeditiously deliver directions to the Trustee with respect to a tender offer. The Administrator shall transmit or cause to be transmitted to the Trustee aggregate numbers of shares to be tendered or withheld from tender representing directions of Participants and Beneficiaries. The Administrator, at its election, may engage an agent to receive directions from Participants and Beneficiaries and transmit them to the Trustee.

(c) The Trustee may establish a reasonable time, taking into account the time restrictions of the tender offer, after which it shall not accept directions of Participants or Beneficiaries.

(d) Notwithstanding the foregoing, with respect to a tender offer for the purchase or exchange of less than five percent (5%) of the outstanding shares of Common Stock, the Investment Office shall direct the Trustee with respect to the sale, exchange or transfer of the shares of Common Stock held in the Trust Fund, and the Trustee shall follow the direction of the Investment Office.

ARTICLE 10

SPECIAL PARTICIPATION AND DISTRIBUTION RULES RELATING

TO REEMPLOYMENT OF TERMINATED EMPLOYEES AND

EMPLOYMENT BY RELATED ENTITIES

Section 10.1. Change of Employment Status.

If an Employee who is not a Participant becomes eligible to participate because of a change in his or her employment status, such Employee shall become a Participant as of the date of such change if either the Employee is not a member of a bargaining unit represented by IBEW Local Union 15 or the Employee has satisfied the eligibility service requirement set forth in Section 3.1; otherwise the Employee shall become a Participant in accordance with Section 3.1 following satisfaction of the eligibility service requirement.

Section 10.2. Reemployment of an Eligible Employee Whose Employment Terminated Prior to His or Her Becoming a Participant.

(a) If the employment of an Eligible Employee who is a member of a bargaining unit represented by IBEW Local Union 15 terminated before the Employee satisfied the eligibility service requirement set forth in Section 3.1 and such Employee is thereafter reemployed by an Employer, such Employee shall be eligible to become a Participant in accordance with Section 3.1.

(b) If the employment of an Eligible Employee who is a member of a bargaining unit represented by IBEW Local Union 15 terminated after he or she had satisfied the eligibility service requirement set forth in Section 3.1 but prior to becoming a Participant is reemployed by an Employer, he or she shall not be required to satisfy again such requirement and shall be eligible to become a Participant upon filing an application in accordance with Section 3.2 (relating to application for Before-Tax Contributions and After-Tax Contributions).

Section 10.3. Reemployment of a Terminated Participant.

If a terminated Participant is reemployed, the Participant shall not be required to satisfy again the eligibility service requirement set forth in Section 3.1 and shall again become a Participant upon filing an application in accordance with Section 3.2 (relating to application for Before-Tax Contributions and After-Tax Contributions).

Section 10.4. Employment by an Affiliate.

If an individual is employed by an Affiliate, then any period of such employment shall be taken into account solely for the purposes of determining whether and when such individual is eligible to participate in the Plan under Article 3 (relating to participation), when such individual has retired or otherwise terminated his or her employment for purposes of Article 8 (relating to withdrawals and distributions) to the same extent it would have been had such period of employment been as an Employee of his or her Employer.

Section 10.5. Leased Employees.

A leased employee (as defined below) shall not be eligible to participate in the Plan. If an individual who performed services as a leased employee (as defined below) of an Employer or an Affiliate becomes an Employee, or if an Employee becomes such a leased employee, then any period during which such services were so performed shall be taken into account solely for the purposes of determining whether and when such individual is eligible to participate in the Plan under Article 3 (relating to participation) and determining when such individual has retired or otherwise terminated his or her employment for purposes of Article 8 (relating to withdrawals and distributions) to the same extent it would have been had such service been as an Employee. This Section shall not apply to any period of service during which such a leased employee was covered by a plan described in section 414(n)(5) of the Code. Any contributions or benefits provided under such plan to a leased employee by his or her leasing organization shall be treated as provided under this Plan and shall be taken into account under Section 7.4 (relating to limitation on allocations imposed by Section 415 of the Code) to the extent required under section 1.415(a)-1(f)(3) of the Regulations. For purposes of this Plan, a "leased employee" shall mean any person who is not an employee of an Employer and who pursuant to an agreement between an Employer or Affiliate has performed services for an Employer or an Affiliate on a substantially full-time basis for a period of at least one year, which services were performed under the primary direction or control of an Employer or an Affiliate.

Section 10.6. Reemployment of Veterans.

(a) General. The provisions of this Section shall apply in the case of the reemployment by an Employer of an Eligible Employee, within the period prescribed by the Uniformed Service Employment and Reemployment Rights Act ("USERRA"), after the Employee's completion of a period of Military Service. The provisions of this Section are intended to provide such Employees with the rights required USERRA and section 414(u) of the Code, and shall be interpreted in accordance with such intent.

(b) Make Up of Before-Tax and After-Tax Contributions. Such Employee shall be entitled to make contributions under the Plan ("Make-Up Employee Contributions"), in addition to Before-Tax and After-Tax Contributions which the Employee elects to have made under the Plan pursuant to Section 4.1 (relating to Before-Tax Contributions). From time to time while employed by an Employer, such Employee may elect to contribute Make-Up Employee Contributions during the period beginning on the date of such Employee's reemployment and ending on the earlier of:

(i) the end of the period equal to the product of three and such Employee's period of Military Service, and

(ii) the fifth anniversary of the date of such reemployment.

Such Employee shall not be permitted to contribute Make-Up Employee Contributions to the Plan in excess of the amount which the Employee could have elected to have made under the Plan in the form of Before-Tax and After-Tax Contributions if the Employee had continued in employment with his or her Employer during such period of Military Service. Such Employee shall be deemed to have earned "Compensation" from his or her Employer during such period of Military Service for this purpose in the amount prescribed by sections 414(u)(2)(B) and 414(u)(7) of the Code. The manner in which an Eligible Employee may elect to contribute Make-Up Employee Contributions pursuant to this paragraph (b) shall be prescribed by the Administrator.

(c) Make Up of Employer Matching Contributions . An Eligible Employee who contributes Make-Up Employee Contributions as described in paragraph (b) shall be entitled to an allocation of Employer Matching Contributions ("Make-Up Matching Contributions") in an amount equal to the amount of Employer Matching Contributions which would have been allocated to the Employer Matching Contributions Account of such Eligible Employee under the Plan if such Make-Up Employee Contributions had been made in the form of Before-Tax or After-Tax Contributions (as applicable) during the period of such Employee's Military Service. The amounts necessary to make such allocation of Make-Up Matching Contributions shall be derived from any forfeitures not yet applied towards Employer Matching Contributions for the Plan Year in which the Make-Up Employee Contributions are made, and if such forfeitures are not sufficient for this purpose, then the Eligible Employee's Employer shall make a special contributions which shall be utilized solely for purposes of such allocation.

(d) Application of Limitations and Nondiscrimination Rules . Any contributions made by an Eligible Employee or an Employer pursuant to this Section on account of a period of Military Service in a prior Plan Year shall not be subject to the limitations prescribed by Sections 4.2, 4.5 and 7.4 of the Plan (relating to sections 402(g), 404 and 415 of the Code) for the Plan Year in which such contributions are made. The Plan shall not be treated as failing to satisfy the nondiscrimination rules of Section 4.4 of the Plan (relating to limitations on contributions for highly compensated Eligible Employees) for any Plan Year solely on account of any make up contributions made by an Eligible Employee or an Employer pursuant to this Section 10.6.

Section 10.7 Transfer of Employment to or from Facilities formerly Owned by CEG . Effective as of the Effective time (as such term is defined in the Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a savings plan qualified under Section 401(a) or 401(k) of the Code (each such plan, a “CEG Savings Plan”) , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Savings Plan. If a participant in the CEG Savings Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Savings Plan and shall not participate in the Plan.

ARTICLE 11

ADMINISTRATION

Section 11.1. The Administrator, the Investment Office and the Corporate Investment Committee .

(a) The Administrator. The Company acting through its Director, Employee Benefit Plans & Programs, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such director or other person or committee, the “Administrator”), shall be the “administrator” of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the “named fiduciary” of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan’s assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe the Plan in regard to all questions of eligibility, the status and rights of Participants, distributees and other persons under the Plan, and the manner, time, and amount of payment of any distribution under the Plan. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in its discretion, determines that such person is entitled to benefits.

(ii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 8 (relating to withdrawals and distributions).

(iii) The Administrator shall supervise the collection of Participants’ contributions made pursuant to Article 5 (relating to Employee contributions) and the delivery of such contributions to the Trustee.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of its duties.

(vi) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vii) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator. The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

(c) The Investment Office. The Investment Office, shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Sections 404(a)(2) and 404(c) of ERISA and the terms of the Plan, and all other applicable limitations. The Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of designating the investment funds under Section 6.2 and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall be solely responsible for all matters involving investment of the Employer Stock Fund described in Section 6.2 and no other person shall have any responsibility with respect to investment of such fund; provided, however, that effective June 21, 2012, the Investment Office has appointed an independent investment manager under section 3(38) of ERISA to manage the investment of the Common Stock in the Employer Stock Fund and such investment manager (rather than the Investment Office) shall be solely responsible for any and all investment decisions relating thereto.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

(d) The Corporate Investment Committee. The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and the Corporate Investment Committee shall have no other duties or responsibilities with respect to the Plan. None of the Company, any officer, employee or member of the board of directors who is not a member of the Corporate Investment Committee, nor any other person shall have any responsibility regarding the appointment or removal of the employees of Investment Office.

(e) Status of Administrator, the Investment Office and the Corporate Investment Committee. The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

(f) Notice to Trustee of Members. The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

(g) Allocation of Responsibilities. Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

(h) General Governance. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

(i) Indemnification. The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

(j) No Compensation. None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, the Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Employer for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

(k) Employ of Counsel and Agents. The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

Section 11.2. Claims Procedure.

Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Sections 13.11 and 13.12) to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the by the Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to such officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by such officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the reviewing officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

Section 11.3. Procedures for Domestic Relations Orders.

If the Administrator receives any written judgment, decree or order (including approval of a property settlement agreement) pursuant to domestic relations or community property laws of any state relating to the provision of child support, alimony or marital property rights of a Spouse, former Spouse, child or other dependent of a Participant and purporting to provide for the payment of all or a portion of the Participant's benefit under the Plan to or on behalf of one or more of such persons (such judgment, decree or order being hereinafter called a "domestic relations order"), the Administrator shall promptly notify the Participant and each other payee specified in such domestic relations order of its receipt and of the following procedures. After receipt of a domestic relations order, the Administrator shall determine whether such order constitutes a "qualified domestic relations order," as defined in paragraph (b) Section 14.2 (relating to exception for qualified domestic relations orders), and shall notify the Participant and each payee named in such order in writing of its determination. Such notice shall be written in a manner calculated to be understood by the parties and shall set forth specific reasons for the Administrator's determination, and shall contain an explanation of the review procedure under the Plan. The Administrator shall also advise each party that the party or his or her duly authorized representative may request a review by the Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) of the Administrator's determination by filing a written request for such review. The Administrator shall give each party affected by such request notice of such request for review. Each party also shall be informed that he or she may have reasonable access to pertinent documents and submit comments in writing to such officer in connection with such request for review. Each party shall be given written notice of the officer's final determination, which notice shall be written in a manner calculated to be understood by the parties and shall include specific reasons for such final determination. Any amounts subject to a domestic relations order which would be payable to the alternate payee prior to the determination that such order is a qualified domestic relations order shall be separately accounted for and not distributed prior to such determination. If within a reasonable time after receipt of written evidence of such order it is determined that such domestic order constitutes a qualified domestic relations order, the amounts so separately accounted for (plus any interest thereon) shall be paid to the alternate payee. If within such reasonable period of time it is determined that such order does not constitute a qualified domestic relations order, the amounts so separately accounted for (plus any interest thereon) shall be paid to such other persons, if any, entitled to such amounts at such time. Prior to the issuance of regulations, the Administrator shall establish the time periods in which the Administrator's determination, a request for review thereof and the review by the Administrator shall be made, provided that the total of such time periods shall not be longer than 18 months from the date written evidence of a domestic relations order is received by the Administrator.

The duties of the Administrator under this Section 11.3 may be delegated by the Administrator to one or more persons other than the Administrator.

Section 11.4. Notices to Participants, Etc.

All notices, reports and statements given, made, delivered or transmitted to a Participant or distributee or any other person entitled to or claiming benefits under the Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or distributee or such other person at the address last appearing on the records of the Administrator. A Participant or distributee or other person may record any change of his or her address from time to time by written notice filed with the Administrator.

Section 11.5. Notices to Administrator.

Written directions, notices and other communications from Participants or distributees or any other person entitled to or claiming benefits under the Plan to the Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the forms prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

Section 11.6. Records.

Each of the Administrator and the Investment Office shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account, records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan or the administration of the investments of the Plan.

Section 11.7. Reports of Trustee and Accounting to Participants.

The Administrator shall keep on file, in such form as it shall deem convenient and proper, all reports concerning the Trust Fund received by it from the Trustee, and the Administrator will, as soon as practicable after the last day of each quarter of each Plan Year furnish each Participant and Beneficiary with a statement reflecting the condition of his or her accounts as of that date.

Section 11.8. Electronic Media.

Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

ARTICLE 12

PARTICIPATION BY OTHER EMPLOYERS

Section 12.1. Adoption of Plan.

With the consent of the Company, any entity may become a participating Employer under the Plan by (a) taking such action as shall be necessary to adopt the Plan and (b) executing and delivering such instruments and taking such other action as may be necessary or desirable to put the Plan into effect with respect to such entity.

Section 12.2. Withdrawal from Participation.

Any Employer shall terminate its participation in the Plan at any time, under such circumstances as the Company may provide, by delivering to the Company a duly certified copy of a resolution of its board of directors (or other governing body) to that effect, or by ceasing to be a member of the same controlled group as the Company (within the meaning of section 1563(a) of the Code).

Section 12.3. Company as Agent for Employers.

Each entity that becomes a participating Employer pursuant to Section 12.1 (relating to adoption of Plan) or Article 13 (relating to continuance by a successor) by so doing shall be deemed to have appointed the Company its agent to exercise on its behalf all of the powers and authorities hereby conferred upon the Company by the terms of the Plan, including, but not by way of limitation, the power to amend and terminate the Plan. The authority of the Company to act as such agent shall continue unless and until the portion of the Trust Fund held for the benefit of Employees of the particular Employer and their Beneficiaries is set aside in a separate Trust Fund as provided in Section 16.2 (relating to establishment of separate trust).

ARTICLE 13

CONTINUANCE BY A SUCCESSOR

In the event that the Employer is reorganized by way of merger, consolidation, transfer of assets or otherwise, so that another entity succeeds to all or substantially all of the Employer's business, such successor entity may be substituted for the Employer under the Plan by adopting the Plan and becoming a party to the Trust agreement. Contributions by the Employer shall be automatically suspended from the effective date of any such reorganization until the date upon which the substitution of such successor entity for the Employer under the Plan becomes effective.

If, within 90 days following the effective date of any such reorganization, such successor entity shall not have elected to become a party to the Plan, or if the Employer adopts a plan of complete liquidation other than in connection with a reorganization, the Plan shall be automatically terminated with respect to Employees of such Employer as of the close of business on the 90th day following the effective date of such reorganization or as of the close of business on the date of adoption of such plan of complete liquidation, as the case may be, and the Administrator shall direct the Trustee to distribute the portion of the Trust Fund applicable to such Employer in the manner provided in Article 16 (relating to establishment of separate plan and termination).

If such successor entity is substituted for an Employer by electing to become a party to the Plan as described above, then, for all purposes of the Plan, employment of such Employee with such Employer, including service with and compensation paid by such Employer, shall be considered to be employment with an Employer.

ARTICLE 14

MISCELLANEOUS

Section 14.1. Expenses.

Except as provided in the last sentence of Section 6.2 (relating to expenses of investments for an investment fund), all costs and expenses incurred in administering the Plan and the Trust, including, but not limited to, “direct expenses” incurred in administering the Plan and the Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust), the expenses of the Administrator and the Investment Office, the fees of counsel and any agents for the Administrator and the Investment Office, the fees and expenses of the Trustee, the fees of counsel for the Trustee and other administrative expenses shall, to the extent permitted by law, be paid from the Trust Fund to the extent such expenses are not paid by the Employers. Notwithstanding the foregoing, the Administrator may authorize an Employer to pay any expenses, and the Employer shall be reimbursed from the Trust Fund for such payments. The Administrator, in its discretion, having regard to the nature of a particular expense, shall determine the portion of the expense that is to be borne by each Employer.

Section 14.2. Non-Assignability.

(a) In general. It is a condition of the Plan, and all rights of each Participant and Beneficiary shall be subject thereto, that no right or interest of any Participant or Beneficiary in the Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not by way of limitation, execution, levy, garnishment, attachment, pledge or bankruptcy, but excluding devolution by death or mental incompetency, and no right or interest of any Participant or Beneficiary in the Plan shall be liable for, or subject to, any obligation or liability of such Participant or Beneficiary, including claims for alimony or the support of any Spouse, except as provided below.

(b) Exception for Qualified Domestic Relations Orders. Notwithstanding any provision of the Plan to the contrary, if a Participant's account balance under the Plan, or any portion thereof, is the subject of one or more qualified domestic relations orders, as defined below, such account balance or portion thereof shall be paid to the person and at the time and in the manner specified in any such order. For purposes of this paragraph (b), "qualified domestic relations order" shall mean any "domestic relations order" as defined in Section 11.3 (relating to procedures for domestic relations orders) that creates (or recognizes the existence of) or assigns to a person other than the Participant (an "alternate payee") rights to all or a portion of the Participant's account balance under the Plan, and:

(A) clearly specifies

(i) the name and last known mailing address (if any) of the Participant and each alternate payee covered by such order,

(ii) the amount or percentage of this Participant's benefits to be paid by the Plan to each such alternate payee, or the manner in which such amount or percentage is to be determined,

(iii) the number of payments to, or period of time for which, such order applies, and

(iv) each plan to which such order applies;

(B) does not require

(i) the Plan to provide any type or form of benefit or any option not otherwise provided under the Plan at the time such order is issued,

(ii) the Plan to provide increased benefits (determined on the basis of actuarial equivalence), and

(iii) the payment of benefits to an alternate payee that at the time such order is issued already are required to be paid to a different alternate payee under a prior qualified domestic relations order; and

(C) does not require the commencement of payment of benefits to any alternate payee before the earlier of (I) the date on which the Participant is entitled to a distribution under the Plan and (II) the date the Participant attains age 50, except that the order may require the commencement of payment of benefits as soon as administratively practicable after the date such order is determined by the Administrator to be a "qualified domestic relations order";

all as determined by the Administrator pursuant to the procedures contained in Section 11.3 (relating to procedures for domestic relations orders). Any amounts subject to a domestic relations order prior to determination of its status as a qualified domestic relations order that but for such order would be paid to the Participant shall be segregated in a separate account or an escrow account pending such determination. If within the reasonable time period beginning with the date on which the first payment would be required to be made under a domestic relations order the Administrator determines that the domestic relations order constitutes a qualified domestic relations order, the amount so segregated (plus any interest thereof) shall be paid to the alternate payee. If such determination is not made within such reasonable time period, then the amount so segregated (plus any interest thereon), shall, as soon as practicable after the end of such reasonable time period, be paid to the Participant. Any determination regarding the status of such order after such reasonable time period shall be applied only to payments on or after the date of such determination.

Section 14.3. Employment Non-Contractual.

The Plan confers no right upon an Employee to continue in employment.

Section 14.4. Limitation of Rights.

A Participant or distributee shall have no right, title or claim in or to any specific asset of the Trust Fund, but shall have the right only to distributions from the Trust Fund on the terms and conditions herein provided.

Section 14.5. Merger or Consolidation with Another Plan.

A merger or consolidation with, or transfer of assets or liabilities to, any other plan shall not be effected unless the terms of such merger, consolidation or transfer are such that each Participant, distributee, Beneficiary or other person entitled to receive benefits from the Plan would, if the Plan were to terminate immediately after the merger, consolidation or transfer, receive a benefit equal to or greater than the benefit such person would be entitled to receive if the Plan were to terminate immediately before the merger, consolidation, or transfer.

Section 14.6. Gender and Plurals.

Wherever used in the Plan, words in the masculine gender shall include masculine or feminine gender, and, unless the context otherwise requires, words in the singular shall include the plural, and words in the plural shall include the singular.

Section 14.7. Applicable Law.

Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

Section 14.8. Severability.

If a provision of the Plan shall be held illegal or invalid, the illegality or invalidity shall not affect the remaining parts of the Plan and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included in the Plan.

Section 14.9. No Guarantee.

Neither the Administrator or the Investment Office, the Employer, nor the Trustee in any way guarantees the Trust from loss or depreciation nor the payment of any money that may be or become due to any person from the Trust Fund. Nothing herein contained shall be deemed to give any Participant, distributee, or Beneficiary an interest in any specific part of the Trust Fund or any other interest except the right to receive benefits out of the Trust Fund in accordance with the provisions of the Plan and the Trust Fund.

Section 14.10. Statute of Limitations for Actions under the Plan.

Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Company's Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

Section 14.11. Forum for Legal Actions under the Plan.

Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

Section 14.12. Legal Fees.

Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Vice President, Health & Benefits, any Plan fiduciary, the Chief Human Resources Officer, the Company, its affiliates or their respective officers, directors, employees, or agents (the “Plan Parties”), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE 15

TOP-HEAVY PLAN REQUIREMENTS

Section 15.1. Top-Heavy Plan Determination.

If as of the determination date (as defined in Section 15.2) for any Plan Year (a) the sum of the account balances under the Plan and all other defined contribution plans in the aggregation group (as defined in Section 15.2) and (b) the present value of accrued benefits under all defined benefit plans in such aggregation group of all Participants in such plans who are key employees (as defined in Section 15.2) for such Plan Year exceeds 60 percent of the aggregate of the account balances and present value of accrued benefits of all participants in such plans as of the determination date (as defined in Section 15.2), then this Plan shall be a top-heavy plan for such Plan Year, and the requirements of Sections 15.3 (relating to minimum contribution for top-heavy years) shall be applicable for such Plan Year as of the first day thereof. If the Plan shall be a top-heavy plan for any Plan Year and not be a top-heavy plan for any subsequent Plan Year, the requirements of this Article shall not be applicable for such subsequent Plan Year.

Section 15.2. Definitions and Special Rules.

(a) Definitions. For purposes of this Article, the following definitions shall apply:

(1) Determination Date. The determination date for all plans in the aggregation group shall be the last day of the preceding Plan Year, and the valuation date applicable to a determination date shall be (i) in the case of a defined contribution plan, the date as of which account balances are determined which is coincident with or immediately precedes the determination date, and (ii) in the case of a defined benefit plan, the date as of which the most recent actuarial valuation for the Plan Year that includes the determination date is prepared, except that if any such plan specifies a different determination or valuation date, such different date shall be used with respect to such plan.

(2) Aggregation Group. The aggregation group shall consist of (a) each plan of an Employer in which a key Employee is a participant, (b) each other plan that enables such a plan to be qualified under section 401(a) of the Code, and (c) any other plans of an Employer that the Company designates as part of the aggregation group and that shall permit the aggregation group to continue to meet the requirements of sections 401(a) and 410 of the Code with such other plan being taken into account.

(3) Key Employee. Key Employee shall have the meaning set forth in section 416(i) of the Code.

(4) Compensation. Compensation shall have the meaning set forth in section 1.415(c)-2 of the Regulations.

(b) Special Rules. For the purpose of determining the accrued benefit or account balance of a Participant, the accrued benefit or account balance of any person who has not performed services for an employer at any time during the 1-year period ending on the determination date shall not be taken into account pursuant to this Section. Any person who received a distribution from a plan (including a plan that has terminated) in the aggregation group during the 1-year period ending on the last day of the preceding Plan Year shall be treated as a Participant in such plan, and any such distribution shall be included in such Participant's account balance or accrued benefit, except that in the case of any distribution made for a reason other than separation from service, death or disability, this sentence shall be applied by substituting "5-year period" for the "1-year period" stated herein.

Section 15.3. Minimum Contribution for Top-Heavy Years.

Notwithstanding any provision of the Plan to the contrary, the sum of the Employer contributions under Article 4 (other than Before-Tax Contributions described in Section 4.1) allocated to the account of each Participant (other than a key Employee) during any Plan Year and the forfeitures allocated to the account of such Participant (other than a key Employee) during any Plan Year for which the Plan is a top-heavy plan shall in no event be less than the lesser of (i) 3% of such Participant's compensation during such Plan Year and (ii) the highest percentage at which contributions are made on behalf of any key Employee for such Plan Year. Notwithstanding the preceding sentence, if the percentage determined pursuant to clause (ii) of the preceding sentence is less than 3%, such percentage shall be recalculated by including Before-Tax Contributions made on behalf of key employees. Such minimum contribution shall be made even if, under other provisions of the Plan, the Participant would not otherwise be entitled to receive an allocation or would receive a lesser allocation for the year because of (i) the Participant's failure to complete 1,000 Hours of Service, or (ii) compensation of less than a stated amount. If, during any Plan Year for which this Section 15.3 is applicable, a defined benefit plan is included in the aggregation group and such defined benefit plan is a top-heavy plan for such Plan Year, the percentage set forth in clause (i) of the first sentence of this Section shall be 5%. The percentage referred to in clause (ii) of the first sentence of this Section shall be obtained by dividing the aggregate of contributions made pursuant to Article 4 and pursuant to any other defined contribution plan that is required to be included in the aggregation group (other than a defined contribution plan that enables a defined benefit plan that is required to be included in such group to be qualified under section 401(a) of the Code) during the Plan Year on behalf of such key Employee by such key Employee's compensation for the Plan Year. Notwithstanding the above, the provisions of this Section 15.3 shall not apply for any Plan Year with respect to an Eligible Employee who has accrued the defined benefit minimum provided under section 416 of the Code under a qualified defined benefit plan maintained by an Employer or Affiliate.

ARTICLE 16

AMENDMENT, ESTABLISHMENT OF SEPARATE PLAN AND TERMINATION

Section 16.1. Amendment.

The Company may at any time and from time to time amend or modify the Plan by resolution of the Board of Directors of the Company or the Compensation Committee thereof; provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility. No amendment shall be made in respect of Eligible Employees who are members of a bargaining unit represented by IBEW Local Union 15 that is inconsistent with that portion of the collective bargaining agreement between such an Employer and IBEW Local Union 15 concerning the Plan.

Section 16.2. Establishment of Separate Plan.

If an Employer withdraws from the Plan under Section 12.2 (relating to withdrawal from participation), the Administrator may determine the portion of the Trust Fund held by the Trustee that is applicable to the Participants and former Participants of such Employer and direct the Trustee to segregate such portion in a separate Trust Fund. Such separate Trust Fund shall thereafter be held and administered as a part of the separate plan of such Employer.

The portion of the Trust Fund applicable to the Participants and former Participants of a particular Employer shall be the sum of:

(a) the total amount credited to all accounts that are applicable to the Participants and former Participants of such Employer and

(b) an amount that bears the same ratio to the excess, if any, of

(i) the total value of the Trust Fund over

(ii) the total amount credited to all accounts

as the total amount credited to the accounts that are applicable to the Participants of such Employer bears to the total amount credited to such accounts of all Participants.

Section 16.3. Termination and Distributions upon Termination of the Plan.

The Company has established the Plan with the bona fide intention and expectation that contributions will be continued indefinitely, but the Company will not have any obligation or liability whatsoever to maintain the Plan for any given length of time and may terminate the Plan at any time by resolution of the Board of Directors or the Compensation Committee thereof, to that effect, without any liability whatsoever for any such termination. Notwithstanding the preceding sentence, the Plan shall not be terminated in respect of Eligible Employees who are members of a bargaining unit represented by IBEW Local Union 15 if such termination is inconsistent with the portion of the collective bargaining agreement between the Employer of such Eligible Employees and IBEW Local Union 15 concerning the Plan. The Plan will be deemed terminated: (a) if and when the Company is judicially declared bankrupt, or (b) upon dissolution of the Company.

Upon termination of the Plan by the Company or withdrawal from participation in the Plan by any Employer pursuant to Section 12.2 (relating to withdrawal from participation) or the partial termination of the Plan with respect to a group of Employees or complete discontinuance of contributions hereunder, distributions shall be made to each affected Participant or other persons entitled to distributions pursuant to Article 8 (relating to withdrawals and distributions). If the entire Plan is terminating, upon the completion of distribution to all Participants, the Trust will terminate, the Trustee will be relieved from all liability under the Trust, and no Participant or other person will have any claims thereunder, except as required by applicable law.

Notwithstanding the preceding paragraph, no distribution shall be made to any Participant (i) until he or she attains age 59 ½ except as otherwise provided in Section 8.3 (relating to distributions upon termination of employment) or (ii) if a successor plan, as defined in Regulations, is established or maintained by the Participant’s Employer.

To the extent that no discrimination in value results, any distribution after termination or partial termination of the Plan may be made, in whole or in part, in cash, in securities or other assets in kind, or in non-transferable annuity contracts, as the Administrator (in its discretion) may determine. All non-cash distributions shall be valued at fair market value at date of distribution.

If the Internal Revenue Service refuses to issue an initial, favorable determination letter that the Plan and Trust Fund as adopted by an Employer meet the requirements of section 401(a) of the Code and that the Trust Fund is exempt from tax under section 501(a) of the Code, the Employer may terminate its participation in the Plan and shall direct the Trustee to pay and deliver the portion of the Trust Fund applicable to the Participants of such Employer, determined pursuant to Section 16.2 (relating to establishment of separate plan) to such Employer and such Employer shall pay to Participants or their beneficiaries the part of such Employer’s portion of the Trust Fund as is attributable to contributions made by Participants.

Notwithstanding any provision of this Plan to the contrary, no distribution shall be made pursuant to this Section 16.3 (relating to termination and distribution upon termination of the Plan) solely due to the termination of this Plan if, within the meaning of applicable Regulations, the employer establishes or maintains an alternative defined contribution plan.

Section 16.4. Trust Fund to Be Applied Exclusively for Participants and Their Beneficiaries .

Subject only to the provisions of Section 4.5 (relating to the limitation on Employer contributions), 7.4 (relating to limitations on allocations imposed by section 415 of the Code) and 16.3 (relating to termination and distributions upon termination of the Plan), and any other provision of the Plan to the contrary notwithstanding, it shall be impossible for any part of the Trust Fund to be used for or diverted to any purpose not for the exclusive benefit of Participants and their Beneficiaries either by operation or termination of the Plan, power of amendment or other means.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officer on this ______ day of December, 2012.

EXELON CORPORATION

By ____
Chief Human Resources Officer

SUPPLEMENT I

Transfers from Other Plans

With the consent of the Administrator, whenever a participant in any other qualified savings or profit sharing plan maintained for employees of an entity any of whose assets or stock are acquired by an Employer (the "Other Plan") becomes a Participant in this Plan, then such Participant's interest in the Other Plan may be transferred to the Trustee of this Plan and credited to administrative subaccounts to be held, invested, reinvested and distributed pursuant to the terms of the Plan and the Trust and, as of the date of the transfer of any such Participant's interest in the Other Plan,

(a) there shall be credited to the Before-Tax Contributions Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the Participant's salary reduction contributions, if any, made to the Other Plan on behalf of the Participant,

(b) there shall be credited to the After-Tax Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the Participant's after-tax contributions, if any, made to the Other Plan,

(c) there shall be credited to the Employer Matching Contributions Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the matching contributions and other employer contributions, if any, made to the Other Plan on behalf of the Participant, and

(d) there shall be credited to the Rollover Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the Participant's rollover contributions, if any, to the Other Plan.

Any amounts credited to a Participant's Before-Tax Contributions Account, After-Tax Contributions Account, Employer Matching Contributions Account and Rollover Account shall be credited to the administrative subaccounts in accordance with such Participant's investment direction in effect as of the date of such transfer. Any salary reduction contributions credited to the Before-Tax Contributions Account that are designated Roth contributions within the meaning of section 402A of the Code shall be maintained in a manner that satisfies the separate accounting requirement, and any Regulations or other requirements promulgated, under section 402A of the Code. Any special provisions applicable to amounts transferred to the Trustee from any Other Plan shall be set forth in an Exhibit hereto.

SUPPLEMENT II

Elective Transfers Between This Plan and Plans of Affiliates or the TXU 401(k) Plan

A. Transfers to this Plan. Whenever an individual who is employed by an Affiliate that is not an Employer has a change in employment status that results in such individual (a) becoming an Eligible Employee and (b) being ineligible to make additional elective contributions under a plan maintained by such Affiliate (an “Affiliate Plan”), such Eligible Employee may elect to transfer his or her benefits under the Affiliate Plan to this Plan. Such election must be conditioned upon a voluntary, fully-informed election by the Eligible Employee. In the event that the Eligible Employee makes such election, his or her benefits under the Affiliate Plan shall be credited to his account under this Plan, and such benefits shall be subject to the terms of, and paid as prescribed by, this Plan, and the terms of the Affiliate Plan shall not apply with respect to such benefits.

An individual who becomes an Eligible Employee in connection with the Company’s 2002 acquisition of from Texas Utilities, Inc. (“TXU”) may elect to transfer his or her benefits under TXU’s 401(k) plan (the “TXU Plan”) to this Plan. Such election must be conditioned upon a voluntary, fully-informed election by the Eligible Employee. In the event that the Eligible Employee makes such election, his or her benefits under the TXU Plan shall be credited to his account under this Plan, and such benefits shall be subject to the terms of, and paid as prescribed by, this Plan, and the terms of the TXU Plan shall not apply with respect to such benefits.

B. Transfers from this Plan. Whenever a Participant has a change in employment status that results in such Participant (a) ceasing to be an Eligible Employee and (b) becoming eligible to participate in an Affiliate Plan, such Participant may elect to transfer his or her benefits under this Plan to the Affiliate Plan. Such election must be conditioned upon a voluntary, fully-informed election by the Participant. In the event that the Participant makes such election, the Participant, effective at the time of the transfer, shall not be entitled to any benefits under this Plan and the benefits transferred to the Affiliate Plan shall be subject to the terms of, and paid as prescribed by, the Affiliate Plan, and the terms of this Plan shall not apply with respect to such benefits.

SUPPLEMENT III

Merger of Certain AmerGen Plans into this Plan

Purpose. The purpose of this Supplement III is to reflect the merger of the AmerGen Clinton Employee Savings Plan for Nonbargaining Employees (the "Clinton Plan") and the AmerGen TMI and Oyster Creek Employee Savings Plan for Nonbargaining Employees (collectively, the "AmerGen Plans") into the Plan effective February 1, 2004 (the "Merger Date") and to preserve those provisions of the AmerGenPlans that cannot be eliminated by amendment without violating section 411(d)(6) of the Internal Revenue Code and applicable Treasury regulations thereunder.

Definitions. Unless the context clearly indicates otherwise, a term defined in the Plan shall have the same meanings for purposes of this Supplement III.

Conflicts Between the Plan and this Supplement III. This Supplement III and the Plan together comprise the Plan with respect to AmerGen Plan Participants (as defined below). In case of any conflict between the provisions of the Plan and this Supplement III, the terms and provisions of this Supplement III shall govern to the extent necessary to eliminate such conflict.

AmerGen Plan Participants. This Supplement III shall be applicable to all AmerGen Plan Participants. "AmerGen Plan Participants" are participants in the Plan who were participants in the AmerGen Plans and whose account balances under the AmerGen Plans were merged into the Plan.

Vesting. All AmerGen Plan Participants shall be fully vested in their accounts under the Plan.

Withdrawals of Employer Matching Contributions. Notwithstanding any provision in the Plan to the contrary, an AmerGen Plan Participant who, immediately prior to the Merger Date was a participant in the Clinton Plan ("Clinton Participant") who has completed 60 months as either a participant in the Clinton Plan or a participant in this Plan may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of his or her Employer Matching Contributions Account that is attributable to contributions made under the Clinton Plan, as adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution. Additionally, a Clinton Participant, regardless of his or her period of participation in the Clinton Plan or this Plan, may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of that portion of the Employer Matching Contributions Account that is attributable to contributions made under the Clinton Plan and that is derived from Employer Matching Contributions in excess of Employer Matching Contributions allocated to his or her Employer Matching Contributions Account during the two Plan Years preceding the Plan Year in which the withdrawal takes place, adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution.

No distribution made pursuant to this paragraph F may be for an amount which is less than the lesser of (i) $200; or (ii) that portion of the Participant's Employer Matching Contributions Account that is attributable to contributions made under the Clinton Plan, as adjusted for gains, earnings and losses attributable thereto. In addition, a Participant may not make more than one withdrawal pursuant to this paragraph F in any Plan Year.

Loans. With respect to any loan to an AmerGen Plan Participant that is outstanding at the Merger Date, the terms of such loan shall continue to be governed by the note evidencing such loan and the terms applicable to such loan as in effect under the AmerGen Plans as of the Merger Date. All loans made after the Merger Date shall be governed by and in accordance with the terms of the Plan and any loan policy issued thereunder by the Administrator.

SUPPLEMENT IV

Merger of New England Plan into this Plan

Purpose. The purpose of this Supplement IV is to reflect the merger of the Exelon New England Union Retirement 401(k) Plan (the "New England Plan") into the Plan effective November 1, 2004 (the "Merger Date").

Definitions. Unless the context clearly indicates otherwise, a term defined in the Plan shall have the same meanings for purposes of this Supplement IV.

Conflicts Between the Plan and this Supplement IV. This Supplement IV and the Plan together comprise the Plan with respect to New England Plan Participants (as defined below). In case of any conflict between the provisions of the Plan and this Supplement IV, the terms and provisions of this Supplement IV shall govern to the extent necessary to eliminate such conflict.

New England Plan Participants. This Supplement IV shall be applicable to all New England Plan Participants. "New England Plan Participants" are participants in the Plan who were participants in the New England Plan and whose account balances under the New England Plan were merged into the Plan.

Vesting. All New England Plan Participants shall be fully vested in their accounts under the Plan.

Loans. With respect to any loan to a New England Plan Participant that is outstanding at the Merger Date, the terms of such loan shall continue to be governed by the note evidencing such loan and the terms applicable to such as in effect under the New England Plan as of the Merger Date. All loans made after the Merger Date shall be governed by and in accordance with the terms of the Plan and any loan policy issued thereunder by the Administrator.

SUPPLEMENT V

Transfers from the Exelon Corporation 401(k) Profit Sharing Plan No. 2

A. Purpose. The purpose of this Supplement IV is to reflect the transfer to the Plan of assets allocated to certain accounts under the Exelon Corporation 401(k) Profit Sharing Plan No. 2 (the "InfraSource Plan No. 2"), which was terminated on November 30, 2007.

B. Definitions. All capitalized terms used in this Supplement IV, but not separately defined herein, shall have the same meanings assigned to such terms in the Plan.

C. Applicability. This Supplement shall apply to any individual ("Affected Participant") whose benefit under the InfraSource Plan No. 2 is transferred pursuant to Section D of this Supplement IV. An Affected Participant shall be treated as a Participant under the Plan for all purposes of the Plan except, unless the Affected Participant is otherwise eligible to participate in the Plan, for purposes related to making or receiving contributions as set forth in Articles 4 and 5 of the Plan.

D. Transfer. Notwithstanding any provision in the Plan to the contrary, assets allocated to the InfraSource Plan No. 2 accounts of any individual who, in connection with the termination of the InfraSource Plan No. 2, elected to transfer his or her benefits thereunder to the Plan or who did not make a timely election with respect to his or her benefits under the InfraSource Plan No. 2, shall be transferred to the Plan as soon as administratively practicable after November 30, 2007 and credited to a separate account ("Affected Account") under this Plan.

E. Conflicts Between the Plan and this Supplement IV. This Supplement IV and the Plan together comprise the Plan with respect to Affected Accounts. In case of any conflict between the provisions of the Plan and this Supplement IV, the terms and provisions of this Supplement IV shall govern to the extent necessary to eliminate such conflict.

F. Vesting. Each Affected Participant shall be fully vested in his or her Affected Account.

Exhibit 10.7

EXELON CORPORATION CASH BALANCE PENSION PLAN

Amended and Restated Effective as of January 1, 2013

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ARTICLE 1
TITLE AND PURPOSE

The name of the plan set forth herein shall be the "Exelon Corporation Cash Balance Pension Plan" (the "Plan"). This Plan, as in effect on December 31, 2012, was previously amended and restated effective generally as of January 1, 2013 and this document represents the subsequent amendment and restatement of the Exelon Corporation Cash Balance Pension Plan as in effect on December 31, 2012 and, except as otherwise provided, shall control and apply to Employees whose employment is terminated on or after January 1, 2013 and to the Beneficiaries of such Employees. The rights and benefits of Employees whose employment terminates before January 1, 2013 and of the Beneficiaries of such Employees shall be determined under the Exelon Corporation Cash Balance Pension Plan as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time; provided, however, that the provisions of Section 6.1(d) (relating to Investment Credits), Article 8 (relating to limitations on benefits), Article 9 (relating to special participation and distribution rules relating to recommencement of employment and employment by related entities), Article 10 (relating to administration), Article 13 (relating to miscellaneous provisions) and Article 15 (relating to amendment and termination of the Plan) shall be effective for all such persons.

ARTICLE 2
DEFINITIONS

As used herein, the following words and phrases shall have the following respective meanings when capitalized:

(1) Accrued Benefit. Except as provided in Section 9.2 (relating to suspension of benefits), the amount payable under the Plan commencing on the first day of the month coinciding with or next following a Participant's Normal Retirement Age, determined as of a date not later than such Participant's Normal Retirement Age as if the Participant had elected Option

1 (the life annuity) under Section 7.2(c) (relating to optional forms of benefit), that is the Actuarial Equivalent of the sum of the balance credited to the Participant's Cash Balance Account as of the date of determination plus Investment Credits (at the rate in effect under Section 6.1(d) (relating to investment credits) on the date of determination) from the date of determination until such assumed date of commencement, plus the Additional Credit, if any, determined as of the date of commencement, subject to adjustment pursuant to Section 7.2(d)(2) (relating to special rules regarding pensions). Notwithstanding the preceding sentence, the Participant's Accrued Benefit attributable to his or her Cash Balance Account, determined as of any date prior to the Participant's Normal Retirement Age, shall be the greater of (a) the amount that would be payable with respect to the sum of the Transition Credit, if any, the Service Credits and the Investment Credits credited to such Participant's Cash Balance Account (the "Account Balance") if the Participant had elected Option 1 (the life annuity) under Section 7.2(c) (relating to optional forms of benefit), that is the Actuarial Equivalent of the Account Balance as of the date of determination projected to the Participant's Normal Retirement Age by crediting such Account Balance with interest calculated on the date of determination to the Participant's Normal Retirement Age, and (b) the amount determined pursuant to the preceding sentence. In addition, a Participant's Accrued Benefit shall include the Participant's Accrued Frozen Benefit. Notwithstanding the preceding sentences or anything contained herein to the contrary, a Participant's Accrued Benefit attributable to his or her Cash Balance Account, determined as of any date on or after August 18, 2006, shall be the Participant's Cash Balance Account.

(2) Accrued Frozen Benefit. The meaning given such term in the applicable Schedule.

(3) Actuarial Equivalent. A benefit of value equivalent to the value of the benefit being replaced, computed using the table specified by the Commissioner of Internal Revenue for purposes of section 417(e)(3) of the Code (which, as of the Effective Date, is the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female) and, as of January 1, 2003, is the 1994 Group Annuity Reserving (GAR) table (unisex basis)) in effect on the date of determination and an interest rate assumption using the "applicable interest rate" as defined in section 417(e)(3) of the Code for the month of November of the Plan Year immediately preceding the Plan Year in which the determination occurs.

(4) Additional Credit. The amount, if any, credited to a Participant's Cash Balance Account pursuant to Section 6.1(e).

(5) Administrator. The Company acting through its Vice President, Health & Benefits or such other person appointed pursuant to Section 10.1 (relating to the Administrator, the Investment Office and the Corporate Investment Committee).

(6) Affiliate. (a) A corporation that is a member of the same controlled group of corporations (within the meaning of section 414(b) of the Code) as an Employer, (b) a trade or business (whether or not incorporated) under common control (within the meaning of section 414(c) of the Code) with an Employer, (c) any organization (whether or not incorporated) that is a member of an affiliated service group (within the meaning of section 414(m) of the Code) that includes (i) an Employer, (ii) a corporation described in clause (a) of this definition or (iii) a trade or business described in clause (b) of this definition, or (d) any other entity that is required

to be aggregated with an Employer pursuant to Regulations promulgated under section 414(o) of the Code. A corporation, trade or business entity shall be an Affiliate only for such period or periods of time during which such corporation, trade or business entity is described in the preceding sentence, but not prior to such time.

(7) Beneficiary. The person or persons entitled to receive a benefit under Section 7.2 (relating to form of distribution) or Section 7.3 (relating to death benefits) in the event of the death of a Participant.

(8) Cash Balance Account. The hypothetical account established for each Participant pursuant to Section 6.1(a) (relating to establishment of accounts).

(9) CEG. Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the Merger Agreement).

(10) Code. The Internal Revenue Code of 1986, as amended.

(11) ComEd Plan. The Commonwealth Edison Company Service Annuity System under the Exelon Corporation Retirement Program.

(12) Company. Exelon Corporation, a Pennsylvania corporation, and any successor to such Company that shall adopt the Plan pursuant to Article 12 (relating to continuance by successor entities).

(13) Compensation. The regular base salary or base wages, as applicable, paid by an Employer to an Eligible Employee for a Plan Year, increased by all payments made during such Plan Year by an Employer to such Eligible Employee under any of the plans set forth in Exhibit A attached hereto, all nuclear license bonuses paid during such Plan Year by an Employer to such Eligible Employee and all amounts not includible in such Eligible Employee's regular base salary or base wages solely on account of his or her election to have compensation reduced pursuant to any qualified cash or deferred arrangement described in section 401(k) of the Code, a qualified transportation fringe benefit program described in section 132(f) of the Code or a cafeteria plan as described in section 125 of the Code, in each case, maintained by an Employer, but excluding any reimbursements or other allowances for automobile, relocation, travel or education expenses (even if includible in the Employee's regular base salary or base wages) and any amount awarded under the Performance Share Award Program for Power Team Employees under the Exelon Corporation Long Term Incentive Plan (or any predecessor or successor program). Notwithstanding the preceding sentence, an Employee's Compensation in excess of the dollar amount prescribed by section 401(a)(17) of the Code (as adjusted for increases in the cost-of-living) shall not be taken into account for any purposes under the Plan. In the case of a Participant who is absent from employment due to a leave of absence for participation in Military Service, Compensation shall mean, for the period during which the Participant is absent due to Military Service, the Participant's Compensation, as defined above, for the twelve-month period preceding the first day of the Participant's absence. Compensation shall also include lump sum merit increases to base salary paid on or after January 1, 2003.

(14) Corporate Investment Committee. The Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

(15) Craft Employee. An Employee who is a non-represented, non-exempt craft or clerical employee assigned to the Peachbottom, Limerick, Outage Services East, Philadelphia Electric Company or Texas generating plant.

(16) Effective Date. Except as otherwise specifically provided herein, January 1, 2013.

(17) Eligible Employee. Except as otherwise provided herein, (a) any Employee who (i) was an Eligible Employee on December 31, 2012, and (ii) is either receiving regular salary or wages from and rendering services to an Employer or is on authorized leave of absence, and (b) on and after January 1, 2013, any Employee who (i) has not, prior to January 1, 2013, had an Hour of Service with any Affiliate, (ii) completed his or her first Hour of Service with an Employer on or after January 1, 2013 and (iii) is either receiving regular salary or wages from and rendering services to an Employer or is on authorized absence. Notwithstanding the preceding sentences, an Eligible Employee shall not include (a) an Employee the terms of whose employment are subject to a collective bargaining agreement that does not provide for participation in this Plan, (b) an Employee paid on the temporary payroll of an Employer who has never completed at least 1,000 Hours of Service in any period of twelve consecutive months beginning with the Employee’s date of employment or anniversary thereof, (c) an Employee who executes a written waiver of his or her right to participate in the Plan, (d) an individual rendering services to an Employer who is not on the payroll of any Employer, (e) an Employee employed by Exelon Generation Company, LLC in the Nuclear Security Division or employed by Exelon Corporation Nuclear Security LLC as an hourly non-exempt nuclear security guard, (f) on or after the Effective Time (as such term is defined in the Merger Agreement), an individual who was employed immediately prior to the Effective Time at CEG or a facility owned immediately before the Effective Time by CEG, (g) an individual who is newly employed on or after the Effective Time (as such term is defined in the Merger Agreement) and prior to January 1, 2013 at a facility owned immediately before the Effective Time by CEG, and (h) an Employee who is newly employed on or after January 1, 2013 by either BGE Home Products & Services, LLC or Constellation Mystic Power, LLC. It is expressly intended that an individual rendering services to an Employer pursuant to any of the following agreements shall be excluded from Plan participation pursuant to clause (d) of this subdivision even if a court or administrative agency determines that such individual is an Employee: (i) an agreement providing that such services are to be rendered as an independent contractor, (ii) an agreement with an entity, including a leasing organization within the meaning of section 414(n)(2) of the Code, that is not an Employer or (iii) an agreement that contains a waiver of participation in the Plan. Notwithstanding anything contained in the Plan to the contrary, any Employer may, at any time, designate, with the consent of the Administrator, a specified group of Employees who will be Eligible Employees.

(18) Employee. An individual whose relationship with an Employer is, under common law, that of an employee.

(19) Employer. The Company and any other Affiliate set forth on Appendix I hereto that, with the consent of the Company, elects to participate in the Plan in the manner described in Article 11 (relating to participation by other employers) either with respect to all Employees or a particular group of Employees of such Affiliate and any successor Affiliate that adopts the Plan pursuant to Article 12 (relating to continuance by successor entities). If any entity described in the preceding sentence withdraws from participation in the Plan pursuant to Section 11.2 (relating to withdrawal from participation) or terminates its participation in the Plan pursuant to Section 15.3 (relating to termination of the Plan by an Employer), such entity shall thereupon cease to be an Employer. Appendix I shall be updated from time to time by the Company to reflect any adoption pursuant to Section 11.1, but the failure to so update such Appendix shall not affect the effectiveness of any such adoption. Such adoptions will be effective whether occurring before, on or after the Effective Date and whether or not reflected in Appendix I.

(20) ERISA. The Employee Retirement Income Security Act of 1974, as amended.

(21) Hour of Service. (a) Each hour for which an Employee is paid, or entitled to payment, for the performance of duties (such hours to be credited to the Employee for the computation period or periods in which the duties are performed); (b) each hour for which an Employee is paid, or entitled to payment, on account of a period of time during which no duties are performed (irrespective of whether a Termination of Employment has occurred) due to vacation, holiday, illness, incapacity (including disability), layoff, jury duty, military duty or leave of absence (such hours to be credited to the Employee for the computation period or periods in which the period of time during which no duties are performed occurs); and (c) each hour for which back pay, irrespective of mitigation of damages, is either awarded or agreed to by an Employer (such hours to be credited to the Employee for the computation period or periods in which the award or agreement pertains rather than the computation period in which the award, agreement or payment is made). Hours of Service shall be computed in accordance with paragraphs (b) and (c) of section 2530.200b-2 of the Department of Labor Regulations.

(22) Investment Credits. The amounts credited to a Participant's Cash Balance Account pursuant to Section 6.1(d).

(23) Investment Office. The Company acting through the Exelon Investment Office.

(24) Merger Agreement. That Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

(25) Military Service. The performance of duty on a voluntary or involuntary basis in a "uniformed service" (as defined below) under competent authority of the United States government and includes active duty, active duty for training, initial active duty for training, inactive duty training, full-time National Guard duty, and a period for which a person is absent from employment for the purpose of an examination to determine the fitness of the person to perform any such duty. For purposes of the preceding sentence, the term "uniformed service" means the Armed Forces, the Army National Guard and the Air National Guard when engaged in active duty for training, inactive duty training, or full-time National Guard duty, the commissioned corps of the Public Health Service, and any other category of persons designated by the President of the United States in time of war or emergency.

(26) Normal Retirement Age. With respect to a Participant's Cash Balance Account, (a) for periods prior to May 23, 2007, the earlier of (a) the date the Participant completes five years of Vesting Service and (b) the later of (i) the Participant's 65th birthday, and (ii) the fifth anniversary of the date the Participant commenced participation in the Plan; and (b) for periods beginning on and after May 23, 2007, the later of (i) the Participant's 62nd birthday, and (ii) the fifth anniversary of the date the Participant commenced participation in the Plan.

(27) Participant. An Eligible Employee who has satisfied the requirements set forth in Article 3 (relating to participation). An Eligible Employee who becomes a Participant shall cease to be a Participant upon the distribution of his or her entire vested benefit under the Plan. Any Participant who upon his or her Termination of Employment has not satisfied the Vesting Requirement shall cease to be a Participant upon such Termination of Employment. Notwithstanding anything in the Plan to the contrary, no Eligible Employee who is hired on or after January 1, 2013 shall become a Participant in the Plan.

(28) PECO Plan. The Service Annuity Plan of PECO Energy Company under the Exelon Corporation Retirement Program.

(29) Pension. A monthly payment continuing for the lifetime of the payee.

(30) Pension Starting Date. The first day as of which an amount becomes payable to a Participant or Beneficiary in accordance with Article 7 (relating to distributions). A Participant or Beneficiary shall have only one Pension Starting Date with respect to the Participant's Accrued Benefit.

(31) Period of Severance. Any twelve-month period commencing on the date an Employee terminates employment or any twelve-month period beginning on the anniversary of such date during which the Employee does not perform any Hours of Service for an Employer. For purposes of this definition, an Employee shall be credited with Hours of Service for any period of absence from an Employer during which such Employee (a) is in Military Service, provided that the Employee returns to the employ of an Employer within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (b) is on an uncompensated leave of absence duly granted by an Employer, or (c) is absent from work for a maximum of twenty-four consecutive months because of (i) the pregnancy of the Employee, (ii) the birth of the Employee's child, (iii) the placement of a child with the Employee in connection with the Employee's adoption of such child, or (iv) the need to care for any such child for a period beginning immediately following such birth or placement. Notwithstanding the foregoing, no Hours of Service shall be credited to an Employee under clause (c) of this subdivision unless the Employee timely furnishes to the Administrator a certificate of birth, proof of adoption or other appropriate legal documentation setting forth parentage or adoption.

(32) Plan. The plan herein set forth and as from time to time amended.

(33) Plan Year. The calendar year.

(34) Qualified Domestic Relations Order. Any domestic relations order which the Administrator has determined, in accordance with procedures established by the Administrator to be a "qualified domestic relations order" defined in section 414(p) of the Code.

(35) Qualified Joint and Survivor Annuity. The form of distribution described in Section 7.2(b) (relating to manner of distribution with respect to married Participants).

(36) Regulations. Written temporary or final regulations of (i) the Department of Labor construing ERISA or (ii) the Treasury Department construing the Code.

(37) Schedule. If a Participant's accrued benefit under the ComEd Plan was transferred to the Plan pursuant to Section 3.1(c) (relating to transfer of benefits and assets to Plan) or Section 9.1 (relating to recommencement of employment by terminated employee), Schedule A and, if a Participant's accrued benefit under the PECO Plan was transferred to the Plan pursuant to Section 3.1(c) or Section 9.1, Schedule B.

(38) Schedule Equivalent. A benefit of value equivalent to the value of the benefit being replaced, computed using the actuarial factors and rules set forth in the applicable Schedule.

(39) Service Credits. The amounts, if any, credited to a Participant's Cash Balance Account pursuant to Section 6.1(c).

(40) Spouse. For periods prior to September 16, 2013, "Spouse" means the individual who is the husband or wife of a Participant as a result of the legal union between one man and one woman, within the meaning of the Defense of Marriage Act, on the Participant's Pension Starting Date or, if earlier, on the date of the Participant's death. Effective September 16, 2013, "Spouse" means the individual who, on a Participant's Pension Starting Date, or if earlier, on the date of the Participant's death, is lawfully married to the Participant under the laws of the state or foreign jurisdiction where the individual and the Participant were married, without regard to the laws of the state where the individual and the Participant are domiciled. For the avoidance of doubt, the term "Spouse" shall not include a person who, with the Participant, is in a domestic partnership, civil union or other similar formal relationship recognized by applicable law. While the Spouse is living and, except as otherwise provided in a qualified domestic relations order as described in Section 13.2(b) (relating to exception to nonassignability in the case of a qualified domestic relations order) or Section 7.4(h) (relating to automatic cancellation of elections), such Spouse shall be treated as the Participant's Spouse for all purposes of the Plan without regard to whether such Spouse remains married to the Participant after the Participant's Pension Starting Date.

(41) Target Income. (a) In the case of a Participant who participated in the ComEd Plan prior to becoming a Participant, Target Income means the sum of (i) the total of the Participant's "basic compensation" as defined in the ComEd Plan for all pay periods ending during calendar year 2001 (for a Participant who was on an authorized leave of absence during calendar year 2001, basic compensation for any pay period during which such Participant did not receive compensation shall be the Participant's average base pay rate per pay period for the twelve-month period preceding the first day of the Participant's leave of absence) and (ii)

“incentive pay” as defined in the ComEd Plan, except that incentive pay shall equal 100% of the target incentive pay the Participant would receive for calendar year 2002 under the applicable plans if the target goals were achieved during 2002, except that incentive pay shall equal 100% of the target incentive pay the Participant would receive for calendar year 2002 under the applicable plans if the target goals were achieved during 2002.

(b) In the case of a Participant who participated in the PECO Plan prior to becoming a Participant, Target Income means the sum of (i) the Participant’s “annual base salary” for 2001 determined in accordance with Section 3.1(b) of the PECO Plan (for a Participant who was on an authorized leave of absence during calendar year 2001, annual base salary for 2001 shall be determined by assuming that for any pay period during which such Participant did not receive compensation, the Participant was paid the base rate in effect immediately prior to the start of the Participant’s leave of absence) and (ii) incentive pay under any Employer’s incentive pay plan (excluding the Performance Share Award Program for Power Team Employees under the Exelon Corporation Long Term Incentive Plan), except that incentive pay shall equal 100% of the target incentive pay the Participant would receive for calendar year 2002 under the applicable plans if the target goals were achieved during 2002.

In determining “incentive pay” for purposes of the preceding subparagraphs, (i) if the Participant’s incentive pay is determined by multiplying his or her compensation by a percentage, the target percentage for 2002 (based on pay-grade in effect as of December 31, 2001) shall be used for such Participant and such target percentage shall be multiplied by the Participant’s 2001 “basic compensation” or “annual base salary”, as applicable, (ii) if the Participant’s incentive pay is defined as a flat dollar amount, the Participant’s incentive pay shall be the 2002 target incentive pay, (iii) if the Participant’s incentive pay is determined by adding quarterly bonus targets and an annual target incentive, the Participant’s incentive pay shall equal the sum of the target quarterly bonuses for calendar year 2002 and the target annual incentive for calendar year 2002, and (iv) if any limits apply to the payment of incentive compensation to a Participant under any applicable incentive pay plan, such limits will apply for purposes of this Plan.

(42) Termination of Employment. A Participant’s ceasing to be an Employee of all Employers and all Affiliates. A transfer between employment by an Employer and employment by an Affiliate or between employment by Employers or Affiliates shall not constitute a Termination of Employment.

(43) Transition Credit. An amount equal to the product of the following: (a) a Participant’s “credited service” under the ComEd Plan or the Participant’s “benefit years” under the PECO Plan, as applicable, determined as of December 31, 2001, (b) the percentage applicable to the Participant determined pursuant to Table T and (c) the Participant’s Target Income. Notwithstanding the preceding sentence, in no event shall a Participant’s Transition Credit exceed 100% of his or her Target Income.

(44) Trust. The Directed Retirement Trust under the Exelon Corporation Cash Balance Pension Plan, as from time to time amended and, effective November 1, 2010, the Exelon Corporation Pension Master Retirement Trust.

(45) Trust Fund. All money and property of every kind held by the Trustee pursuant to the terms of the agreement governing the Trust.

(46) Trustee. The trustee provided for in Article 5 (relating to the Trust) or any successor trustee or, if there is more than one such trustee acting at any time, all of such trustees collectively.

(47) Vesting Requirement. For periods beginning prior to May 23, 2007, a Participant's attainment, during the time such Participant is an Employee, of his or her Normal Retirement Age. For periods beginning on and after May 23, 2007, the earlier of (a) the date a Participant completes the applicable years of Vesting Service described in the following sentence and (b) the date the Participant's attains, during the time such Participant is an Employee, his or her Normal Retirement Age. For purposes of the preceding sentence, the applicable years of Vesting Service are, for Plan Years beginning before January 1, 2008, five years, and for Plan Years beginning on and after January 1, 2008, three years.

(48) Vesting Service. The period of an Employee's employment which is used to determine whether the Employee has satisfied the Vesting Requirement. An Employee's Vesting Service includes the aggregate of the periods during which the Employee is employed by an Employer or an Affiliate beginning on the day on which the Employee first performs an Hour of Service with an Employer or Affiliate, provided that in the case of an Employee who has no vested right to any benefits under this Plan, such Employee's periods of employment before and after a period of absence from employment shall be aggregated only when the Employee's number of consecutive one-year Periods of Severance is less than five and the Employee has at least one year of Vesting Service after such period of absence from employment. For purposes of the preceding sentence, an Employee shall be deemed to be employed by an Employer or an Affiliate during (a) any period of absence from employment by an Employer or an Affiliate which is of less than twelve months' duration, (b) the first twelve months of any period of absence from employment for any reason other than the Employee's quitting, retiring or being discharged, (c) the period during which the Employee is not rendering services to any Employer or Affiliate as a result of a disability during which period the Employee is receiving benefits under any Employer's or Affiliate's long-term disability plan and (d) any period during which the Employee is in Military Service, provided that the Employee returns to the employ of an Employer or an Affiliate within the period prescribed by laws relating to the reemployment rights of persons in Military Service. The Administrator may require certification from an Employee, as a condition of granting Vesting Service under this subdivision, that the leave was taken for one of the reasons enumerated in the preceding sentence. Notwithstanding the preceding sentences, in determining an Employee's period of absence from employment by an Employer or an Affiliate, the following shall be disregarded: the first twenty-four months of any period of absence from employment by reason of (i) the Employee's pregnancy, (ii) the birth of the Employee's child, (iii) the placement of a child with the Employee in connection with the adoption of such child by such Employee or (iv) caring for such child for a period beginning immediately following such birth or placement. Notwithstanding anything in this definition to the contrary, the Vesting Service for a Participant who elects to participate in the Plan pursuant to Section 3.1(b) (relating to eligibility for participation for employees other than new hires) and whose accrued benefit under the PECO Plan is transferred to the Plan pursuant to Section 3.1(c) (relating to transfer of benefits and assets to Plan) shall be (a) for periods prior to January 1,

2002, the vesting service credited to the Participant under the terms of the PECO Plan, as in effect on December 31, 2001, and (b) for the Participant's "eligibility computation period" (as defined in the PECO Plan) that ends during the 2002 Plan Year, the greater of (i) the Vesting Service, for such period, determined pursuant to this subdivision and (ii) the vesting service, for such period, determined pursuant to the terms of the PECO Plan.

ARTICLE 3
PARTICIPATION

Section 3.1 Eligibility for Participation. (a) General. Each Eligible Employee who immediately before the Effective Date was a Participant in the Plan shall continue to be a Participant as of the Effective Date. Each other Eligible Employee who has not, prior to the Effective Date, had an Hour of Service with any Affiliate and whose first Hour of Service with an Employer is on or after the Effective Date shall become a Participant as of the first day that such Eligible Employee completes an Hour of Service with an Employer as an Eligible Employee.

(b) Other Employees Prior to the Effective Date. Each individual who (a) is, at any time between January 1, 2002 and April 30, 2002, an Employee and (b) was, on December 31, 2000, a participant in either the ComEd Plan (other than a participant the terms of whose employment are subject to a collective bargaining agreement) or the PECO Plan, or would have been a participant in the PECO Plan if the age and service requirements for participation in the PECO Plan were disregarded, shall be permitted to elect, in the time and manner prescribed by the "Committee," as such term was defined in the Plan prior to June 1, 2006, to either (i) continue participating in the ComEd Plan or the PECO Plan, as the case may be, on and after January 1, 2002 (or begin participating in the PECO Plan, in the case of an Employee who will satisfy the eligibility and age and service requirements for participation in such plan on January 1, 2002) or (ii) cease participating in the applicable Plan described in clause (i) hereof as of

December 31, 2001 and begin participating in the Plan as of January 1, 2002 (or, if later, his or her employment or reemployment date). Each such Eligible Employee who affirmatively elects to participate in the Plan in lieu of participation in the ComEd Plan or the PECO Plan shall become a Participant as of January 1, 2002 (or, if later, his or her employment or reemployment date), unless such Participant receives a notification (the "Notice") from an Employer that his or her employment with the Employers and their Affiliates will be terminated on or before December 31, 2002 and that such Participant is eligible for severance benefits under the Exelon Corporation Merger Separation Plan for Designated Management Employees or any other severance plan maintained by an Employer or an Affiliate. An Eligible Employee who receives a Notice shall not become a Participant, notwithstanding such Eligible Employee's election to participate in the Plan. An Eligible Employee (i) who receives a Notice, but whose employment does not terminate on or before December 31, 2002, or (ii) whose employment terminates before December 31, 2002 without the Employee receiving a Notice shall become a Participant as of January 1, 2002 (or, if later, his or her employment or reemployment date) if such Employee elects, in the time and manner prescribed by the "Committee," as such term was defined in the Plan prior to June 1, 2006, to participate in the Plan.

In the case of an Eligible Employee who became an employee of the Power Team during 2003 pursuant to Exelon Way, such Eligible Employee shall continue to be a Participant. In addition, each Eligible Employee who was an employee of the Power Team on any date in 2003 and who became an employee of a participating business unit of an Employer during 2003 in connection with Exelon Way shall continue to be a Participant only if such Employee was a Participant prior to the date on which such Employee became an employee of a participating business unit of an Employer. Effective as of January 1, 2004, each individual (i) who either (A) is an employee of the Power Team or (B) transferred employment from the Power Team to a participating business unit of an Employer during 2003 pursuant to Exelon Way, (ii) who became an Eligible Employee on or after January 1, 2004 and (iii) who either (A) has a frozen accrued benefit under this Plan or (B) does not have an accrued benefit under either the ComEd Plan or the PECO Plan shall become a Participant as of the later of January 1, 2004 and the date the Eligible Employee completes an Hour of Service with an Employer as an Eligible Employee. In addition, each Eligible Employee (i) who either (A) is an employee of the Power Team or (B) transferred employment from the Power Team to a participating business unit of an Employer during 2003 pursuant to Exelon Way, (ii) who became an Eligible Employee on January 1, 2004, (iii) who has an accrued benefit under either the ComEd Plan or the PECO Plan, (iv) who is not described in the preceding sentence and (v) who did not previously make a valid election pursuant to the preceding paragraph shall be permitted to elect, in the time and manner prescribed by the "Committee," as such term was defined in the Plan prior to June 1, 2006, to either (A) resume or continue participation in the ComEd Plan or the PECO Plan, as the case may be, as of January 1, 2004 or (B) participate in the Plan as of January 1, 2004. Each such Eligible Employee who affirmatively elects to participate in the Plan in lieu of participation in the ComEd Plan or the PECO Plan shall become a Participant as of January, 1, 2004.

(c) Transfer of Benefits and Assets to Plan. If an Employee described in paragraph (b) above elects to participate in the Plan in lieu of participating in the ComEd Plan or the PECO Plan, as the case may be, the Employee's accrued benefit under either such plan, determined as of December 31, 2001, or December 31, 2003, as the case may be, in accordance with the provisions of the applicable plan, shall be transferred to the Plan. An amount of assets that is equal to the present value of the Employee's accrued benefit described in the preceding sentence determined using the methods and assumptions prescribed by section 4044 of ERISA shall also be transferred to the Plan. Such transfer of benefits and assets related thereto shall occur as soon as practicable after the Eligible Employee makes the election described in paragraph (b) above. Each Participant whose benefits are so transferred shall be permitted to have his or her Accrued Frozen Benefit paid in any of the optional forms of benefit listed in the applicable Schedule in lieu of the forms provided hereunder. The provisions set forth in the applicable Schedule shall govern all matters relating to a Participant's Accrued Frozen Benefit.

In the event that an Eligible Employee whose accrued benefit under the ComEd Plan or the PECO Plan, and related assets, is transferred to the Plan receives a Notice and has a Termination of Employment on or before December 31, 2002, the accrued benefit, and related assets, transferred to the Plan shall be transferred back to the ComEd Plan or the PECO Plan, as the case may be, and the amount of the pension benefit accrued by such Employee during 2002 (if any) shall be determined under the terms of the ComEd Plan or the PECO Plan, as applicable, rather than the Plan. Such transfer shall occur as soon as administratively practicable.

Section 3.2 Transfer to Affiliates. If a Participant is transferred from one Employer to another Employer or from an Employer to an Affiliate that is not an Employer, then such transfer shall not terminate the Participant's participation in the Plan and the Participant shall continue to participate in the Plan until an event occurs that would have entitled the Participant to a complete distribution of the Participant's vested Pension had the Participant continued to be employed by an Employer until the occurrence of such event. Nevertheless, except to the extent provided in Section 9.3 (relating to employment by related entities) or Section 9.7 (relating to change in employment status or transfer to affiliate), a Participant shall not be entitled to receive Service Credits under Section 6.1(c) (relating to Service Credits) during any period of employment by any Affiliate that is not an Employer with respect to such Participant, and periods of employment with an Affiliate that is not an Employer with respect to such Participant shall be taken into account only to the extent set forth in Section 9.3 (relating to employment by related entities) or Section 9.7 (relating to change in employment status or transfer to affiliate).

Section 3.3 Cessation of Participation. An individual's participation in the Plan shall cease upon the date the individual is no longer eligible to receive a benefit from this Plan or upon the individual's Termination of Employment if the individual has not satisfied the Vesting Requirement upon the date of his or her Termination of Employment.

Section 3.4 Rehired Participants. Notwithstanding anything contained herein to the contrary, if a Participant terminates employment and is reemployed as an Employee under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees, including that the Participant waives participation in, or additional benefits and accruals under the Plan, such Participant shall not be entitled to receive any Service Credits under Section 6.1(c) (relating to Service Credits) during such period of reemployment.

ARTICLE 4
SOURCE OF CONTRIBUTIONS

Section 4.1 Source of Contributions. The Employers intend to make contributions to the Trust of amounts which, in the aggregate over a period of time, shall be sufficient to finance the benefits provided by the Plan. Any such contributions shall be in such amounts and shall be made in such manner and at such time as the Company may from time to time determine in accordance with the funding policy it establishes and consistent with minimum funding standards under section 412 of the Code, provided, however, that all contributions made by the Employers for any Plan Year shall be made prior to the due date, including extensions thereof, of the Employers' federal income tax return for the taxable year of the Employers which coincides with such Plan Year. The Company may rely on the advice of actuaries in establishing and carrying out a funding policy. Forfeitures arising under the Plan for any reason shall be applied to reduce the cost of the Plan, not to increase the benefits otherwise payable to the Participants.

Section 4.2 Limitation on Contributions. The contributions of an Employer for any Plan Year shall not exceed the maximum amount for which a deduction is allowable to such Employer for federal income tax purposes for the taxable year of such Employer that ends with or within such Plan Year. Any contribution made by an Employer by reason of a good faith mistake of fact, or the portion of any contribution made by an Employer that exceeds the maximum amount for which a deduction is currently allowable to such Employer for federal income tax purposes, shall upon the request of such Employer be returned by the Trustee to the Employer. An Employer's request and the return of any such contribution must be made within one year after such contribution was mistakenly made or after the deduction of such excess portion of such contribution was disallowed, as the case may be. The amount to be returned to an Employer pursuant to this Section shall be the excess of (i) the amount contributed over (ii) the amount that would have been contributed had there not been a mistake of fact or the maximum amount that is so deductible, as the case may be. Earnings attributable to the mistaken contribution shall not be returned to the Employer, but losses attributable thereto shall reduce the amount to be so returned.

ARTICLE 5
TRUST

A trust (the "Trust") has been created by the execution of a trust agreement between the Company and a trustee (the "Trustee") for purposes of holding and administering the assets of the Plan. All contributions under the Plan shall be paid to the Trustee. The Trustee shall hold all monies and other property received by it and invest and reinvest the same, together with the income therefrom, on behalf of the Participants collectively in accordance with the provisions of such trust agreement. The Trustee shall make distributions from the Trust Fund at such time or times to such person or persons and in such amounts as the Administrator directs in accordance with the Plan.

ARTICLE 6
PARTICIPANT ACCOUNTS

Section 6.1 Cash Balance Accounts. (a) Establishment of Accounts. A separate Cash Balance Account shall be established for each Participant. Each such account shall have an initial balance of zero until credited with any Transition Credit, if applicable, or Service Credit as provided herein. Each such account shall be for accounting purposes only, and there shall be no segregation of assets among such accounts. A Participant's Cash Balance Account shall cease to be maintained as of the Participant's Pension Starting Date (except to the extent such Pension Starting Date is required by Section 7.1(b) (relating to distributions to five percent owners)), in which case the Participant's Cash Balance Account shall cease to be maintained as of the first January 1 following the Participant's Termination of Employment).

(b) Transition Credit. A Participant's Cash Balance Account shall be credited, as of the first day of the Plan Year in which such Participant becomes a Participant, with an amount equal to the Participant's Transition Credit, provided that (a) the Participant is an Employee on January 1, 2002 and becomes a Participant pursuant to Section 3.1(b) (relating to eligibility for participation for employees who are not new hires) and (b) the Participant is not an employee of the Power Team. An Employee who becomes a Participant pursuant to Section 3.1(a) (relating to eligibility for participation for new hires) shall not be credited with a Transition Credit at any time and a rehired Employee who becomes a Participant pursuant to Section 9.1 (relating to recommencement of employment by terminated employee) shall not be credited with a Transition Credit at the time of his or her rehire.

(c) Service Credits. A Participant's Cash Balance Account shall be credited, as of the last day of each Plan Year during which the Participant is a Participant and an Eligible Employee, with an amount equal to the following percentage of Compensation received by such Participant during such portion of such Plan Year that the Participant was an Eligible Employee: (i) for each Plan Year beginning before January 1, 2008 and, in the case of a Participant whose employment is subject to a collective bargaining agreement that provides for participation in this Plan, for each Plan Year thereafter, 5.75%, (ii) for each Plan Year beginning on and after January 1, 2008 if the Participant's employment is not subject to a collective bargaining agreement and either the Participant first became a Participant prior to January 1, 2013 or the Participant is a Craft Employee, 7.00%, and (iii) for each Plan Year beginning on and after January 1, 2013 for a Participant who first becomes a Participant on or after January 1, 2013, other than a Craft Employee or an Employee subject to a collective bargaining agreement, the applicable amount specified below:

For Participants Who Become Participants on or After January 1, 2013 (Other than Craft Employees)

Participant's Age as of the End of the Plan Year	Annual Service Credit
Under age 30	3%
Age 30 to 34	4%
Age 35 to 39	5%
Age 40 to 44	6%
Age 45 to 49	7%
Age 50 and older	8%

Notwithstanding the foregoing, if a Participant's Pension Starting Date occurs other than on the last day of a Plan Year and if the Participant is entitled to have an amount credited to his or her Cash Balance Account for such Plan Year pursuant to the preceding sentence, such amount shall be credited to the Participant's Cash Balance Account as of the last day of the month before such Pension Starting Date (and prior to the crediting of any Investment Credit for such Plan Year). No amount shall be credited pursuant to this paragraph (c) to the Cash Balance Account of a Participant who is not rendering services to any Employer or Affiliate as a result of a disability, regardless of whether such Participant is receiving benefits under any Employer's or Affiliate's long-term disability plan.

(d) Investment Credits. (1) For Participants who were Participants Prior to January 1, 2013 or are Craft Employees . The provisions of this paragraph shall apply only with respect to the Cash Balance Account of a Participant who was a Participant prior to January 1, 2013 or is a Craft Employee. For each Plan Year beginning before January 1, 2008, the Cash Balance Account of a Participant described in this paragraph (d)(1) shall be credited, as of the last day of each Plan Year during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year, with an amount equal to the product of (i) the "Pre-

2008 Plan Interest Rate" (as defined below) multiplied by (ii) the balance of such Participant's Cash Balance Account as of the first day of such Plan Year. For each Plan Year beginning on and after January 1, 2008, such Participant's Cash Balance Account shall be credited, as of the last day of each Plan Year during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year, with an amount equal to the sum of the following amounts: (i) the product of (A) the "Pre-2008 Plan Interest Rate" (as defined below) multiplied by (B) the balance of such Participant's Cash Balance Account as of December 31, 2007, if any; and (ii) the product of (A) the "Post-2007 Plan Interest Rate" (as defined below) multiplied by (B) the portion of such Participant's Cash Balance Account attributable to Service Credits credited after December 31, 2007, determined as of the first day of such Plan Year. A Participant described in this paragraph (d)(1) who is not rendering Services to any Employer or Affiliate as a result of a disability with respect to which such Participant is receiving benefits under any Employer's or Affiliate's long-term disability plan shall be credited with the amount described in the first and second sentences of this paragraph (d), as applicable. Notwithstanding the preceding sentences, if a Participant's Pension Starting Date occurs other than on the last day of a Plan Year, the amount to be credited to the Participant's Cash Balance Account pursuant to this paragraph (d)(1) for the Plan Year in which the Participant's Pension Starting Date occurs shall be equal to the product of (i) 4% (or, for Plan Years beginning on and after January 1, 2008, the "Post-2007 Plan Interest Rate," as defined below, for the immediately preceding Plan Year) multiplied by (ii) a fraction, the numerator of which is the number of whole calendar months during such Plan Year prior to and including the month which contains the date immediately preceding the Participant's Pension Starting Date and the denominator of which is twelve, and such Investment Credit shall be made as of the last day of the month before such Pension

Starting Date prior to the crediting of any Service Credit for such year. Except to the extent provided in Section 7.2(d)(2) (relating to special rules regarding pensions), a Participant's Cash Balance Account shall not be credited with Investment Credits after the Participant's Pension Starting Date.

For purposes of this paragraph (d)(1), the "Pre-2008 Plan Interest Rate" for any Plan Year shall mean a percentage equal to the greater of (i) 4% and (ii) the average of (A) the "applicable interest rate" as defined in section 417(e)(3) of the Code for the month of November of such Plan Year and (B) the annual percentage rate of return for the S&P 500 Stock Index for the 12-month period ending on December 31 of such Plan Year, as reported in The Wall Street Journal on the first business day of the succeeding year. For purposes of this paragraph (d)(1), the "Post-2007 Plan Interest Rate" for any Plan Year shall mean a percentage equal to the third segment rate of interest on long-term investment grade corporate bonds, as provided for in section 430(h)(2)(C) of the Code for the month of November of such Plan Year (determined by not taking into account any adjustment under clause (iv) thereof).

(2) For Participants who Became Participants on or After January 1, 2013 (Other than Craft Employees) . The provisions of this paragraph shall apply only with respect to the Cash Balance Account of a Participant who became a Participant on or after January 1, 2013, other than a Craft Employee. The Cash Balance Account of a Participant described in this paragraph (d)(2) shall be credited, as of the last day of each Plan Year during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year, with an amount equal to the product of (i) the "Plan Interest Rate" (as defined below) multiplied by (ii) the balance of such Participant's Cash Balance Account as of the first day of such Plan Year. A Participant described in this paragraph (d)(2) who is not rendering Services to any Employer

or Affiliate as a result of a disability with respect to which such Participant is receiving benefits under any Employer's or Affiliate's long-term disability plan shall be credited with the amount described in the preceding sentence. Notwithstanding the preceding sentences, if a Participant's Pension Starting Date occurs other than on the last day of a Plan Year, the amount to be credited to the Participant's Cash Balance Account pursuant to this paragraph (d)(2) for the Plan Year in which the Participant's Pension Starting Date occurs shall be equal to the product of (i) the Plan Interest Rate multiplied by (ii) a fraction, the numerator of which is the number of whole calendar months during such Plan Year prior to and including the month which contains the date immediately preceding the Participant's Pension Starting Date and the denominator of which is twelve, and such Investment Credit shall be made as of the last day of the month before such Pension Starting Date prior to the crediting of any Service Credit for such year. Except to the extent provided in Section 7.2(d)(2) (relating to special rules regarding pensions), a Participant's Cash Balance Account shall not be credited with Investment Credits after the Participant's Pension Starting Date.

For purposes of this paragraph (d)(2), the "Plan Interest Rate" for any Plan Year shall mean a percentage equal to the greater of (i) 3.8%, and (ii) the lesser of (A) the second segment rate of interest on long-term corporate bonds, as determined under Section 430(h)(2)(C) of the Code for the month of November of such Plan Year (determined by not taking into account any adjustment under clause (iv) thereof), and (B) 7%.

(e) Additional Credit. If, as of a Participant's Pension Starting Date, the amount described in (1) below exceeds the amount described in (2) below, an amount equal to the difference between such amounts shall be credited the Participant's Cash Balance Account as of the day before such Pension Starting Date:

(1) The cumulative amount that would have been credited to the Participant's Cash Balance Account if the Plan Interest Rate described in Section 6.1(d) of the Plan (relating to Investment Credits) were credited to the Participant's "Opening Credit" (as defined below) for each Plan Year during which the Participant is a Participant at the Plan Interest Rate then in effect, whether or not such Participant is an Eligible Employee during such Plan Year.

(2) The cumulative amount that would have been credited to the Participant's Cash Balance Account if 6.5% interest were credited to the Participant's "Opening Credit" (as defined below) for all Plan Years during which the Participant is a Participant, whether or not such Participant is an eligible Employee during such Plan Year.

If the amount described in (1) above is equal to or less than the amount described in (2) above, no amount shall be credited to the Participant's Cash Balance Account pursuant to this paragraph (e). In addition, no amount shall be credited pursuant to this paragraph (e) if a Participant does not have an Accrued Frozen Benefit.

For purposes of this paragraph (e), "Opening Credit" shall mean an amount equal to the present value of a Participant's Accrued Frozen Benefit determined as of December 31, 2001 using a 6.5% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female) assuming the Accrued Frozen Benefit otherwise payable at the Schedule A Retirement Date would commence at the later of the Participant's attained age as of December 31, 2001 or age 60.

ARTICLE 7
DISTRIBUTIONS

Section 7.1 Time of Distribution. (a) In General. A Participant who has satisfied the Vesting Requirement shall be entitled to receive a distribution of the aggregate of the balance of his or her Cash Balance Account and his or her Accrued Frozen Benefit in the manner provided by Section 7.2 (relating to form of distribution) commencing as soon as practicable after the first day of the month immediately following the date on which the Participant's Termination of

Employment occurs. Notwithstanding the preceding sentence, a Participant whose Termination of Employment occurs prior to such Participant's attainment of age 70-1/2 shall be deemed to have elected to defer receipt of his or her Cash Balance Account and Accrued Frozen Benefit until the April 1 next following the date the Participant attains age 70-1/2, unless the Participant elects, in the time and manner described in the following sentence, to receive a distribution prior to such date. The Participant may elect to commence such distribution by giving the Administrator not less than 30 nor more than 90 days advance written notice of the Pension Starting Date desired by the Participant; provided, however, that the Administrator may waive such advance written notice requirement if the Participant submits the appropriate form to the Administrator in accordance with the requirements set forth in Section 7.4(d) (relating to notice of availability of optional forms of benefit). A Participant who has satisfied the Vesting Requirement and who does not make an election as described in the preceding sentence prior to such Participant's attainment of age 70-1/2 shall receive a distribution of the aggregate of the balance of his or her Cash Balance Account and his or her Accrued Frozen Benefit in the manner provided by Section 7.2 (relating to form of distribution) commencing no later than April 1 next following the date the Participant attains age 70-1/2.

(b) Distributions to Five Percent Owners. Notwithstanding any provision of the Plan to the contrary, if a Participant who has satisfied the Vesting Requirement and who is a "five percent owner" (as described in section 416(i) of the Code) remains employed by an Employer through April 1 of the year following the year in which the Participant attains age 70 ½, distribution of the balance of the Participant's Cash Balance Account and his or her Accrued Frozen Benefit shall commence on such April 1 (or such later date as may be provided by the Code or Regulations). Any other Participant who remains in such employment shall not be permitted to commence distribution of such Participant's Cash Balance Account or Accrued Frozen Benefit at the time specified in the preceding sentence unless required by the Code or Regulations.

(c) Immediate Distribution of Small Benefits. Notwithstanding any provision of the Plan to the contrary, if, as of the date of a Participant's Termination of Employment (including on account of death), the aggregate of the balance of the Participant's Cash Balance Account and the lump sum Schedule Equivalent of the Participant's Accrued Frozen Benefit does not exceed $5,000 or, for distributions occurring on or after March 28, 2005, $1,000, such Participant or, in the event of the Participant's death, such Participant's Beneficiary or Beneficiaries, shall receive a distribution in the amount and in the form described in Option 2 of Section 7.2(c) (relating to lump sum distribution) as soon as practicable following such Termination of Employment in satisfaction of all benefits to which the Participant or his or her Beneficiaries, as the case may be, is entitled under the Plan.

(d) Deemed Distributions. If a Participant has not satisfied the Vesting Requirement upon his or her Termination of Employment, such Participant's vested interest in his or her benefit under the Plan shall have a value of zero, such Participant shall be deemed to have received immediately after such termination a lump sum distribution of such vested interest and concurrent therewith shall forfeit all benefits hereunder, and the Participant's Cash Balance Account and Accrued Frozen Benefit shall no longer be maintained.

Section 7.2 Form of Distribution. (a) Manner of Distribution With Respect to Unmarried Participants. A Participant who is not married on his or her Pension Starting Date shall have the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any, distributed in the form of a Pension for the life of the Participant unless the Participant elects an optional form of distribution described in paragraph (c) of this Section (relating to optional forms of distributions) at the time and in the manner described in Section 7.4 (relating to election and waiver procedures).

(b) Manner of Distribution With Respect to Married Participants. A Participant who is married on his or her Pension Starting Date shall have the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any, distributed in the form of a Pension payable to the Participant for the life of the Participant and, thereafter, if the Participant's Spouse survives the Participant, a Pension payable to the Spouse during the remaining lifetime of such Spouse equal to 50% of the Pension payable to the Participant during the Participant's lifetime. Notwithstanding the preceding sentence, the Participant, with the consent of his or her Spouse, may elect an optional form of distribution described in paragraph (c) of this Section (relating to optional forms of distributions) at the time and in the manner described in Section 7.4 (relating to election and waiver procedures).

(c) Optional Forms of Distribution. Upon written request to the Administrator made at the time and in the manner prescribed in Section 7.4 (relating to election and waiver procedures), a Participant may elect to receive a distribution of the Participant's benefit under the Plan in one of the following optional forms in lieu of the form described in paragraph (a) or (b) of this Section (relating to manner of distribution with respect to unmarried Participants and married Participants, respectively):

Option 1: Life Annuity. If the Participant is married on his or her Pension Starting Date, a Pension payable for the life of the Participant in an amount that is the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any.

Option 2: Lump Sum Distribution. Except as otherwise provided in Section 7.8 (relating to special rules applicable to calculations of lump sum distributions), a single, lump sum distribution in an amount equal to the sum of (a) the balance credited to the Participant's Cash Balance Account as of the last day of the month immediately preceding the date of such distribution and (b) the lump sum Schedule Equivalent of the Participant's Accrued Frozen Benefit.

Option 3: Survivor Annuity. A reduced Pension payable to the Participant during the Participant's lifetime and, thereafter, if the designated Beneficiary survives the Participant, a Pension equal to 100%, 75% or 50% (whichever is specified when this option is elected) of such reduced Pension payable to the Designated Beneficiary during the remaining lifetime of such Designated Beneficiary, the aggregate amount of which are the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any.

(d) Special Rules Regarding Pensions.

(1) If a Participant's spouse dies before the Participant's Pension Starting Date and the Participant has not elected an optional form of distribution described in paragraph (c) of this Section (relating to optional forms of distribution), the Participant shall again be entitled to make an election under this Section.

(2) If a Pension commences pursuant to Section 7.1(b) (relating to distributions to five percent owners) while a Participant remains employed by an Employer, such Pension shall be actuarially adjusted as of January 1 following the end of each calendar year during which such Participant remains employed by an Employer to reflect any additional Service Credits and Investment Credits credited to the Participant's Cash Balance Account as of December 31 of the preceding calendar year.

(3) If a Participant elects Option 3 under Section 7.2(c) and the Participant's Beneficiary is other than the Participant's Spouse, the Pension payable to the Participant and to the Beneficiary shall be adjusted as is necessary to satisfy the incidental benefit requirement under section 401(a)(9) of the Code. Notwithstanding anything in the Plan to the contrary, the form and timing of all distributions under the Plan to any Participant shall be in accordance with Section 401(a)(9) of the Code and regulations issued thereunder, including the incidental death benefit requirements of Section 401(a)(9)(G) of the Code and Treasury Regulation §1.401(a)(9)-2 through Treasury Regulation §1.401(a)(9)-9.

Section 7.3 Death Benefits. (a) Eligibility. If a Participant who has satisfied the Vesting Requirement dies prior to his or her Pension Starting Date, the Participant's surviving Beneficiary shall be entitled to receive a benefit under this Section. In addition, if a Participant dies while an Employee, the Participant's surviving Beneficiary shall be entitled to receive a benefit under this Section, regardless of whether the Participant has satisfied the Vesting Requirement.

(b) Form of Payment. A surviving Beneficiary who is entitled to a distribution of the Participant's benefit under this Section shall receive the following, as applicable:

(1) Lump Sum Payment. Except as otherwise provided in Section 7.8 (relating to special rules applicable to calculations of lump sum distributions), a lump sum payment that is equal to the sum of (a) the balance credited to the Participant's Cash Balance Account as of the last day of the month immediately preceding the date of such distribution and (b) the lump sum Schedule Equivalent of the Participant's Accrued Frozen Benefit shall be payable to the Participant's surviving Beneficiary not later than the fifth anniversary of the Participant's death, except that if the Participant's surviving Beneficiary is the Participant's surviving Spouse, distribution to such surviving Spouse may commence at the same time as described in subparagraph (2). Notwithstanding the foregoing, should any benefit be payable pursuant to subparagraph (2) of this Section 7.3(b) (relating to statutory surviving Spouse's benefit), the amount of any benefit payable pursuant to this subparagraph (1) shall be reduced by the Actuarial Equivalent of the benefit payable pursuant to such subparagraph (2).

(2) Statutory Surviving Spouse's Benefit. If the Participant is survived by a Spouse to whom the Participant was married throughout the one-year period ending on the date of the Participant's death, then, unless such Participant has with his or her Spouse's consent waived the benefit described herein in the manner described in Section 7.4(e) (relating to waiver of statutory surviving Spouse's benefit), such Spouse shall be entitled to receive a survivor's Pension commencing as of any January 1 coinciding with or following the date of the Participant's death or any succeeding January 1 (but not later than the January 1 immediately preceding or coinciding with the date the Participant would have attained age 70-1/2 had he or she survived) and continuing for the lifetime of such Spouse in an amount equal to the Pension such Spouse would have received pursuant to a Qualified Joint and Survivor Annuity if the Participant had survived until such day and such Qualified Joint and Survivor Annuity had commenced on such day and the Participant had died immediately after such annuity commenced, but determined without regard to any Service Credits that would have been credited to the Participant's Cash Balance Account with respect to any periods subsequent to the Participant's Termination of Employment.

(c) The death benefits provided by this Section shall not be effective to the extent required to comply with the terms of a Qualified Domestic Relations Order.

Section 7.4 Election and Waiver Procedures. (a) Election of Optional Form of Benefit. Subject to paragraph (c) of this Section (relating to spousal consent to election of optional form of benefit or beneficiary designation), a Participant may elect, change or revoke any form of distribution provided under Section 7.2 (relating to forms of distribution) at any time during the 90-day period ending on the later of the Participant's Pension Starting Date and the date the Participant's benefit is paid or commences. Such an election, change or revocation shall be made by the Participant delivering a written notice describing the election, change or revocation to the Administrator on a form provided by the Administrator for this purpose.

(b) Beneficiary Designation. Subject to paragraph (e) below (relating to waiver of statutory surviving spouse's benefit), each Participant may designate one or more Beneficiaries to receive any payment pursuant to Section 7.3(b)(1) (relating to lump sum pre-retirement death benefit) in the event of his or her death. A Participant may from time to time, without the consent of any Beneficiary, change or cancel any such designation. Such designation and each change therein shall be made in the form prescribed by the Administrator and shall be filed with the Administrator. If no Beneficiary has been designated by a deceased Participant, or the designated Beneficiary has predeceased the Participant, any payment pursuant to Section 7.3(b)(1) (relating to lump sum pre-retirement death benefit) shall be made by the Trustee at the direction of the Administrator (i) to the surviving Spouse of such deceased Participant, if any, or (ii) if there shall be no surviving Spouse, to the surviving children of such deceased Participant, if any, in equal shares, or (iii) if there shall be no surviving Spouse or surviving children, to the executor or administrator of the estate of such deceased Participant, or (iv) if no executor or administrator shall have been appointed for the estate of such deceased Participant within six months following the date of the Participant's death, in equal shares to the person or persons who would be entitled under the intestate succession laws of the state of the Participant's domicile to receive the Participant's personal estate. The marriage of a Participant shall be deemed to revoke any prior designation of a Beneficiary made by him or her and a divorce shall be deemed to revoke any prior designation of the Participant's divorced Spouse if written evidence of such marriage or divorce shall be received by the Administrator before distribution shall have been made in accordance with such designation. If, within a period of three years following any Participant's death or other termination of employment by an Employer, the Administrator in the exercise of reasonable diligence has been unable to locate the person or persons entitled to benefits under this Article in respect of such Participant, the rights of such person or persons shall be forfeited and the Administrator shall direct the Trustee to pay such benefit or benefits to the person or persons next entitled thereto under the succession prescribed by this Section.

(c) Spousal Consent to Election of Optional Form of Benefit or Beneficiary Designation . If a Participant is married on his or her Pension Starting Date, and if after giving effect to an election, revocation or change described in paragraph (a) of this Section (relating to election of optional form of benefit) the Participant's Spouse would not be entitled to receive a survivor's benefit at least equal to that provided by Section 7.2(b) (relating to manner of distribution with respect to married Participants), such election, revocation or change shall not be effective unless it shall have been consented to at the time of such election, revocation or change in writing by the Participant's Spouse and such consent acknowledges the effect of such election and is witnessed by a notary public. The consent of a Spouse to such an election, revocation or change shall not be required if it is established to the satisfaction of the Administrator that such consent cannot be obtained because there is no Spouse, the Spouse cannot be located or such other circumstances as may be prescribed in Regulations. If the Spouse is legally incompetent to give consent, the consent may be executed by the Spouse's legal guardian (including the Participant, if the Participant is the legal guardian). An election of an optional form of distribution shall be deemed a rejection of the distribution form provided by paragraph (a) or (b) of Section 7.2 (relating to manner of distribution with respect to unmarried Participants and manner of distribution with respect to married Participants). The consent of a Spouse otherwise required by this paragraph shall not be necessary for a distribution required by a Qualified Domestic Relations Order.

(d) Notice of Availability of Optional Forms of Benefit. No less than 30 days (or such shorter period as may be permitted by applicable law) and no more than 90 days before the later of a Participant's Pension Starting Date and the date the Participant's benefit is paid or commences, the Administrator shall give the Participant by mail or personal delivery written notice in non-technical language that he or she may elect an optional form of distribution set forth in Section 7.2 (relating to form of distribution); provided, however, that the Participant may waive (with applicable spousal consent) such 30-day notice period as long as the Participant's distribution commences not less than eight days after such notice is provided. Such notice shall include a general description of the eligibility conditions and other material features of the optional forms of distribution provided under the Plan; the circumstances under which the basic forms of distribution set forth in Section 7.2 (relating to form of distribution) will be provided unless a Participant, with the consent of the Participant's Spouse, elects otherwise; the

Participant’s right to revoke any such election; and information regarding the financial effect, in terms of dollars per payment, upon his or her distribution if he or she elects an optional form of distribution or revokes any prior election. Notwithstanding the foregoing, the notice described in the previous paragraph may be provided to the Participant subsequent to the Participant’s Pension Starting Date, if the Participant so elects, provided that the following conditions are satisfied:

(i) the date on which the first payment to be received by the Participant is made (the “initial payment date”) shall be no earlier than thirty (30) days following the date that the notice is furnished to the Participant, except that the initial payment date may be as early as the eighth day after such notice is provided if (i) such notice clearly indicates that the Participant has a right to a period of thirty (30) days after receiving the notice to consider to waive the basic forms of distribution provided under the Plan and to elect (with spousal consent) an optional form of benefit, (ii) the Participant affirmatively elects a form of distribution with the consent of his or her spouse (if required) to commence as of the initial payment date, and (iii) the Participant is permitted to revoke such election until the initial payment date;

(ii) the notice shall be provided to the Participant no more than ninety (90) days before the initial payment date, however, the Plan will not fail to satisfy the ninety (90)-day requirement if the delay in providing the distribution is due solely to an administrative delay;

(iii) the Participant is not permitted to elect a Pension Starting Date that precedes the date upon which the Participant could have otherwise started receiving benefits under the terms of the Plan as in effect on the Pension Starting Date;

(iv) to the extent that a Participant has not received any payments for the period from the Pension Starting Date to the initial payment date, the Participant shall receive a one-time payment to reflect any such missed payments (a “make-up payment”). Such make-up payment shall be adjusted for interest from the period beginning on the Pension Starting Date and ending on the initial payment date, which shall be calculated with respect to such payments that would have been received prior to the initial payment date. The interest rate used to compute the adjustment described in the preceding sentence shall equal the 30 Year Treasury rate for December of the preceding Plan Year. For purposes of Section 8.1 (relating to statutory limits), the limitations set forth therein shall comply with the adjustments required thereto pursuant to Treasury Regulation 1.417(e)-1 with respect to any Pension Starting Date described in this paragraph which is a “retroactive annuity starting date” as defined for purposes of such Regulation; and

(v) if a Participant who is married elects to commence the Participant's benefit as of the initial payment date pursuant to this paragraph, then the Participant's spouse (including an alternate payee who is treated as the Participant's spouse under a qualified domestic relations order), determined as of the initial payment date, must consent to such election if the survivor benefits payable as of the Pension Starting Date are less than the survivor benefits payable under the benefit described in Option 3 of Section 7.2(b) of the Plan as of the initial payment date.

(e) Waiver of Statutory Surviving Spouse's Benefit. A Participant may waive the statutory surviving spouse's benefit provided by Section 7.3(b)(2) at any time prior to the Participant's death, provided, however, that if such waiver is made prior to the Plan Year in which the Participant attains age 35, such waiver shall become invalid on the first day of such year unless the Participant has terminated employment by the Employers prior to such day. A Participant whose waiver becomes invalid pursuant to the preceding sentence may elect, at any time after the waiver becomes invalid, to again waive the statutory surviving spouse's benefit provided by Section 7.3(b)(2). A waiver made pursuant to this paragraph (e) shall be made by delivering a written notice thereof to the Administrator on a form provided by the Administrator for this purpose with a written consent of the Participant's Spouse which satisfies the requirements of paragraph (b) of this Section (relating to beneficiary designation) (unless it is determined pursuant to paragraph (c) of this Section that such consent is not needed). Such a waiver shall cease to be effective if, subsequent to the execution of such waiver, the Participant shall make any other Beneficiary designation pursuant to paragraph (b) of this Section (relating to beneficiary designation) which diminishes the rights or contingent rights of the Participant's Spouse, which are specified in the Beneficiary designation in effect at the time such Spouse consented to such waiver, to all or part of the benefit provided under Section 7.3(b) (relating to form of payment of pre-retirement death benefits), provided, however, that in no event shall such other Beneficiary designation affect the effectiveness of such waiver if such Spouse shall have so specified at the time of consent. A waiver described in this paragraph shall cease to be effective on (i) the date on which the Participant is subsequently married to a person other than the Spouse who consented to such waiver, (ii) the Participant's Pension Starting Date, or (iii) the date of the Participant's revocation of such waiver.

(f) Notice of Right to Waive Statutory Surviving Spouse's Benefit. Not later than twelve months after the day on which an Employee has become a Participant, the Administrator shall give the Participant by mail or personal delivery written notice in nontechnical language that he or she may waive the statutory surviving spouse's benefit provided by Section 7.3(b)(2). Such notice shall include a general description of terms and conditions of such benefit and the circumstances under which it will be provided unless waived and the Participant's right to revoke any such waiver and general information on the relative financial effect, if any, upon the Participant's Pension of such benefit and its waiver. Such notice shall also advise the Participant that, upon written request to the Administrator prior to the end of the waiver period set forth in paragraph (e) of this Section (relating to waiver of statutory surviving spouse's benefit), he or she will be given a written explanation in nontechnical language of the terms and conditions of such benefit and the financial effect, in terms of dollars per payment, upon his or her other death benefits if he or she does not waive such benefit. Such explanation shall be mailed or personally delivered to the Participant within 30 days from the date his or her written request is received by the Administrator.

(g) Election of Optional Form of Statutory Surviving Spouse's Benefit. A surviving Spouse may elect to have the statutory surviving spouse's benefit provided by Section 7.3(b)(2) payable in the form of Option 2 of Section 7.2(c) (relating to optional forms of distribution). Such an election may be made at any time prior to the commencement of such benefit and not thereafter. Such an election shall be made by delivering a written notice thereof to the Administrator on a form provided by the Administrator for this purpose.

(h) Automatic Cancellation of Elections. If a Participant's Pension is payable in the form of a joint and survivor annuity and if, prior to the Participant's Pension Starting Date, the Participant's Spouse dies or the Participant and such Spouse divorce, the Participant's election or deemed election to receive a joint and survivor annuity shall, upon the Participant's notice to the Administrator of such death or divorce, be automatically cancelled, unless, subsequent to such Spouse's death or the Participant's divorce and prior to the Participant's Pension Starting Date, the Participant remarries and notice of such new marriage is timely received by the Administrator.

Section 7.5 Distributions to Minor and Disabled Distributees. Any distribution under this Article that is payable to a distributee who is a minor or to a distributee who, in the opinion of the Administrator, is unable to manage his or her affairs by reason of illness or mental incompetency may be made to or for the benefit of any such distributee at such time consistent with the provisions of Section 7.2 (relating to form of distribution) and in such of the following ways as the legal representative of such distributee shall direct: (i) directly to any such minor distributee if, in the opinion of such legal representative, he or she is able to manage his or her affairs, (ii) to such legal representative, (iii) to a custodian under a Uniform Gifts to Minors Act for any such minor distributee, or (iv) directly in payment of expenses of support or maintenance of such person. Neither the Administrator nor the Trustee shall be required to see to the application by any third party other than the legal representative of a distributee of any distribution made to or for the benefit of such distributee pursuant to this Section.

Section 7.6 Direct Rollover Distributions. In the case of a distribution under this Plan that is an "eligible rollover distribution" within the meaning of section 402 of the Code and that is at least $200, an eligible distributee (as defined below) may elect that all or any portion of such distribution to which such eligible distributee is entitled shall be directly transferred as a rollover contribution from the Plan to (i) an individual retirement account described in section 408(a) of the Code, (ii) an individual retirement annuity described in section 408(b) of the Code, (iii) an annuity plan described in section 403(a) of the Code, (iv) a retirement plan qualified under section 401(a) of the Code, (v) an annuity contract described in section 403(b) of the Code, (vi) an eligible plan under section 457(b) of the Code which is maintained by an eligible employer described in section 457(e)(1)(A) of the Code (the terms of which permit the acceptance of rollover contributions) or (vii) effective January 1, 2008, a Roth IRA described in section 408A of the Code; provided, however, that (x) with respect to a plan described in clause (vii), for transfers occurring before January 1, 2010, the Participant (or surviving spouse of a Participant or a former spouse who is an alternate payee under a qualified domestic relations order as defined in section 414(p) of the Code) meets the requirements of section 408A(c)(3)(B) of the Code and (y) with respect to a distribution (or portion of a distribution) to a person who is not the Participant or the surviving spouse or former spouse of the Participant, "eligible retirement plan" shall mean only a plan described in clause (i), (ii) or (vii) that, in either case, is established for the purpose of receiving such distribution on behalf of such person. For purposes of this Section, "eligible distributee" shall include the Participant, his or her spouse or his or her former spouse who is an alternate payee under a qualified domestic relations order within the meaning of section 414(p) of the Code and, effective January 1, 2010, the Participant's Beneficiary who is not the Participant's spouse or former spouse. Notwithstanding the foregoing, an eligible distributee shall not be entitled to elect to have less than the total amount of such distribution transferred as a rollover contribution unless the amount to be transferred equals at least $500.

Section 7.7 Withholding Requirements. Any benefit payment made under the Plan will be subject to any applicable income tax withholding requirements.

Section 7.8 Special Rules Applicable to Calculations of Lump Sum Distributions . Notwithstanding anything contained herein to the contrary, if a lump sum distribution is paid to a Participant prior to the Participant's Normal Retirement Age and prior to May 23, 2007, the portion of any lump sum payment made under Section 7.2(c), Option 2, or Section 7.3(b)(1) that, in either case, is attributable to the Participant's Cash Balance Account shall be the greater of (x) the balance credited to the Participant's Cash Balance Account as of the last day of the month immediately preceding the date of such distribution and (y) the Actuarial Equivalent of the Participant's Accrued Benefit.

Section 7.9 Participant's Death During Qualified Military Service . Effective January 1, 2007, in the case of a Participant who dies while performing Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any (other than benefit accruals relating to the period of Military Service), provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

ARTICLE 8
LIMITATIONS ON BENEFITS

Section 8.1 Statutory Limits. The provisions of this Section shall be effective for any "Limitation Year" (as defined below) solely to the extent required by the Code or Regulations for such year.

Notwithstanding any other provision of the Plan to the contrary, the amount of the Participant's annual benefit (as defined below) accrued, distributable or payable at any time under the Plan shall be limited to an amount such that such annual benefit and the aggregate annual benefit of the Participant under all other defined benefit plans maintained by the Employer or any other Affiliate does not exceed the lesser of:

(i) $160,000 (as increased to reflect the cost of living adjustments provided under section 415(d) of the Code), multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of participation (within the meaning of Treasury Regulation section 1.415(b)-1(g)(1)(ii)) and the denominator of which is 10; or

(ii) an amount equal to 100% of the Participant's average compensation for the three consecutive calendar years in which his or her compensation was the highest (as determined in accordance with Treasury Regulation section 1.415(b)-1(a)(5)) and which are included in his or her years of service (within the meaning of Treasury Regulation section 1.415(b)-1(g)(2)(ii)) with the Employers multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of service and the denominator of which is 10.

The dollar amount set forth in clause (i) of the preceding paragraph shall be actuarially reduced in accordance with Treasury Regulation section 1.415(b)-1(d) if the Participant's Pension Starting Date occurs prior to the Participant's attainment of age 62. If the Participant's Pension Starting Date occurs after the Participant attains age 65, such dollar amount shall be actuarially increased in accordance with Treasury Regulation section 1.415(b)-1(e).

A Participant's "annual benefit" shall mean the Participant's accrued benefit payable annually in the form of a straight life annuity, as determined in, and accordance with, Treasury Regulation section 1.415(b)-1(b). If the annual benefit is payable in a form other than a single life annuity, the annual benefit shall be adjusted to the Actuarial Equivalent of a single life annuity using the assumptions of the following sentences; provided, however, that no adjustment shall be required for survivor benefits payable to a surviving Spouse under a Qualified Joint and Survivor Annuity (as described in Section 7.2(b)) to the extent such benefits would not be payable if the Participant's annual benefit were paid in another form.

Effective for Plan Years beginning January 1, 2004 and January 1, 2005, for any form of benefit subject to section 417(e)(3) of the Code, a Participant's annual benefit shall be the greater of (i) the amount computed using the interest rate and mortality table specified under subdivision (3) of Article 2 (relating to definition of Actuarial Equivalent) as in effect and (ii) the amount computed using an interest rate assumption of 5.5% and the applicable mortality table under Treasury Regulation section 1.417(e)-1(d)(2) (the "Applicable Mortality Table"). Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit subject to section 417(e)(3) of the Code, a Participant's annual benefit shall be the greatest of (i) the amount computed using the interest rate and mortality table specified under subdivision (3) of Article 2 (relating to definition of Actuarial Equivalent) as in effect, (ii) the amount computed using an interest rate assumption of 5.5% and the Applicable Mortality Table and (iii) the amount computed using the applicable interest rate under Treasury Regulation section 1.417(e)-1(d)(3) and the Applicable Mortality Table, divided by 1.05. Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit not subject to section 417(e)(3) of the Code, a Participant's annual benefit shall be determined in accordance with Treasury Regulation section 1.415(b)-1(c). An individual's "annual benefit" under any other defined benefit plan maintained by the Employer and Affiliate shall be as determined pursuant to the provisions of section 415 of the Code and the Regulations issued thereunder the terms of such plan.

Notwithstanding the foregoing provisions of this Section, the limitation provided by this Section shall not apply to a Participant who has not at any time participated in a defined contribution plan maintained by any Employer and whose annual benefit under the Plan does not exceed $10,000 multiplied by a fraction (not exceeding 1 and not less than 1/10th) the numerator of which is the Participant's years of service (within the meaning of Treasury Regulation section 1.415(b)-1(g)(2)(ii))) and the denominator of which is 10.

For purposes of this Section, the term "compensation" shall have the meaning set forth in section 415(c)(3) of the Code and the applicable Regulations, the term "defined contribution plan" shall have the meaning set forth in Treasury Regulation section 1.415(c)-1(a)(2), the term "defined benefit plan" shall have the meaning set forth in Treasury Regulation section 1.415(b)-1(a)(2) and the term "Employer" shall include the Employers and all corporations and entities required to be aggregated with any of the Employers pursuant to section 414(b) and (c) of the Code as modified by section 415(h) of the Code. Section 415 of the Code and the Regulations thereunder are hereby incorporated by reference.

Section 8.2 Restrictions on Benefits. (a) The annual Plan payments to a Participant in the Restricted Group (as defined below) for any Plan Year may not exceed an amount equal to the annual payments that would be made to or on behalf of the Participant under:

(i) a single life annuity that is equal to the Participant's Accrued Benefit and any other Benefits (as defined below) to which the Participant is entitled under the Plan (disregarding any Social Security supplement within the meaning of section 1.411(a)-7(c)(4)(ii) of the Treasury Regulations), plus

(ii) the amount of any payment to which the Participant is entitled as a Social Security supplement under the Plan.

(b) Application of Restriction. The restriction set forth in paragraph (a) of this Section (relating to restrictions on benefits) shall not apply to any payment if any of the following conditions is satisfied at the date as of which the payment is to be made:

(i) after reduction to reflect the present value of all Benefits payable to or on behalf of the Participant under the Plan, the value of the Plan's assets would equal or exceed 110% of the value of the Plan's current liabilities, as defined in section 412(l)(7) of the Code;

(ii) the present value of the Benefits payable to or on behalf of the Participant under the Plan is less than 1% of the value of the Plan's current liabilities, as defined in section 412(l)(7) of the Code; or

(iii) the present value of the Benefits payable to or on behalf of the Participant under the Plan does not exceed $5,000 (or such greater amount as may be set forth in section 411(a)(11)(A) of the Code).

(c) Plan Termination Rule. In the event of termination of the Plan, the benefit of any Participant in the Restricted Group shall be limited to a benefit that is nondiscriminatory under section 401(a)(4) of the Code.

(d) Definitions. For purposes of this Section:

(i) "Restricted Group" consists of the highly compensated employees and highly compensated former employees (within the meaning of section 414(q) of the Code) of the Employer and its Affiliates, but the total number in the Restricted Group for any calendar year shall be limited to 25 and shall consist of those highly compensated active and highly compensated former employees with the greatest compensation in the current or any prior year for which compensation information is available.

(ii) The term "Benefit" includes, without limitation, any periodic income from the Plan, any withdrawal values payable to a living employee under the Plan, any Plan loans in excess of the amounts set forth in section 72(p)(2)(A) of the Code and any Plan death benefits not provided for by insurance on the employee's or former employee's life.

(iii) The "current liability" of the Plan as of any date may be based on the current liability reported on Schedule B of the Plan's most recent, timely-filed Form 5500 or 5500 C/R. For purposes of this Section, the value of the Plan's assets shall be determined on the same date as of which the current liability is determined.

(e) Effective Date. The restrictions set forth in this Section shall cease to be in effect when (i) a condition set forth in subparagraph (b)(i), (b)(ii) or (b)(iii) above is satisfied, (ii) the Participant is not in the Restricted Group, (iii) the Plan is terminated and the benefit received by the Participant is nondiscriminatory or (iv) such restrictions are not required to be applied to such payment under the Code or Regulations.

Section 8.3 Benefit Restrictions as a Result of Funding. Effective January 1, 2010, notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's adjusted funding target attainment percentage is at or below the following levels.

(a) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 80%, But Not Less Than 60%. If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 80% (or would be less than 80% to the extent described in subparagraph (a)(2) below) but is not less than 60%, then the limitations set forth in this paragraph (a) apply.

(1) 50% Limitation on Single Sum Payments, Other Accelerated Forms of Distribution, and Other Prohibited Payments. A Participant or Beneficiary is not permitted to elect, and the Plan shall not pay, a lump sum distribution or other optional form of distribution that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any

payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, unless the present value of the portion of the benefit that is being paid in a prohibited payment does not exceed the lesser of:

(i) 50% of the present value of the benefit payable in the optional form of benefit that includes the prohibited payment; or

(ii) 100% of the PBGC maximum benefit guarantee amount (as defined in Treasury Regulation section 1.436-1(d)(3)(iii)(C)).

The limitation set forth in this subparagraph (a)(1) does not apply to any payment of a benefit which under section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant. If an optional form of benefit that is otherwise available under the terms of the Plan is not available to a Participant or Beneficiary as of the annuity starting date because of the application of the requirements of this subparagraph (a)(1), the Participant or Beneficiary is permitted to elect to bifurcate the benefit into unrestricted and restricted portions (as described in Treasury Regulation section 1.436-1(d)(3)(iii)(D)). The Participant or Beneficiary may also elect any other optional form of benefit otherwise available under the Plan at that annuity starting date that would satisfy the 50% limitation described in subparagraph (a)(1)(i) above or the PBGC maximum benefit guarantee amount described in subparagraph (a)(1)(ii) above, or may elect to defer the benefit in accordance with any general right to defer commencement of benefits under the Plan.

(2) Plan Amendments Increasing Liability for Benefits . No amendment to the Plan that has the effect of increasing liabilities of the Plan by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accrual, or changing the rate at which benefits become nonforfeitable shall take effect in a Plan Year if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 80%; or

(ii) 80% or more, but would be less than 80% if the benefits attributable to the amendment were taken into account in determining the adjusted funding target attainment percentage.

The limitation set forth in this subparagraph (a)(2) does not apply to any amendment to the Plan that provides a benefit increase under a Plan formula that is not based on compensation, provided that the rate of such increase does not exceed the contemporaneous rate of increase in the average wages of Participants covered by the amendment.

(b) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 60% (or would be less than 60% to the extent described in subparagraph (b)(2) below), then the limitations in this paragraph (b) apply.

(1) Single Sums, Other Accelerated Forms of Distribution, and Other Prohibited Payments Not Permitted . A Participant or Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment. The limitation set forth in this subparagraph (b)(1) does not apply to any payment of a benefit which under section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(2) Shutdown Benefits and Other Unpredictable Contingent Event Benefits Not Permitted to Be Paid . An unpredictable contingent event benefit with respect to an unpredictable contingent event occurring during a Plan Year shall not be paid if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 60%; or

(ii) 60% or more, but would be less than 60% if the adjusted funding target attainment percentage were redetermined applying an actuarial assumption that the likelihood of occurrence of the unpredictable contingent event during the Plan Year is 100%.

(3) Benefit Accruals Frozen. Benefit accruals under the Plan shall cease as of the applicable section 436 measurement date. In addition, if the Plan is required to cease benefit accruals under this subparagraph (b)(3), then the Plan is not permitted to be amended in a manner that would increase the liabilities of the Plan by reason of an increase in benefits or establishment of new benefits.

(c) Limitations Applicable If the Plan Sponsor Is In Bankruptcy . Notwithstanding any other provisions of the Plan, a Participant or Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date that occurs during any period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, except for payments made within a Plan Year with an annuity starting date that occurs on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. In addition, during such period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, except for payments that occur on a date within a Plan Year that is on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. The limitation set forth in this paragraph (c) does not apply to any payment of a benefit which under section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(d) Provisions Applicable After Limitations Cease to Apply .

(1) Resumption of Prohibited Payments . If a limitation on prohibited payments under subparagraph (a)(1), (b)(1), or (c) of this Section applied to the Plan as of a section 436 measurement date, but that limit no longer applies to the Plan as of a later section 436 measurement date, then that limitation does not apply to benefits with annuity starting dates that are on or after that later section 436 measurement date.

(2) Resumption of Benefit Accruals . If a limitation on benefit accruals under subparagraph (b)(3) of this Section applied to the Plan as of a section 436 measurement date, but that limitation no longer applies to the Plan as of a later section 436 measurement date, then benefit accruals shall resume prospectively and that limitation does not apply to benefit accruals that are based on service on or after that later section 436 measurement date, except as otherwise provided under the Plan. The Plan shall comply with the rules relating to partial years of participation and the prohibition on double proration under Department of Labor Regulation section 2530.204-2(c) and (d).

(3) Shutdown and Other Unpredictable Contingent Event Benefits . If an unpredictable contingent event benefit with respect to an unpredictable contingent event that occurs during the Plan Year is not permitted to be paid after the occurrence of the event because of the limitation of subparagraph (b)(2) of this Section, but is permitted to be paid later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan Year that meets the requirements of Treasury Regulation section 1.436-1(g)(5)(ii)(B)), then that unpredictable contingent event benefit shall be paid, retroactive to the period that benefit would have been payable under the terms of the Plan (determined without regard to subparagraph (b)(2) of this Section). If the unpredictable contingent event benefit does not become payable during the Plan Year in accordance with the preceding sentence, then the Plan is treated as if it does not provide for that benefit.

(4) Treatment of Plan Amendments That Do Not Take Effect. If a Plan amendment does not take effect as of the effective date of the amendment because of the limitation of subparagraph (a)(2) or (b)(3) of this Section, but is permitted to take effect later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan Year that meets the requirements of Treasury Regulation section 1.436-1(g)(5)(ii)(C)), then the Plan amendment must automatically take effect as of the first day of the Plan Year (or, if later, the original effective date of the amendment). If the Plan amendment cannot take effect during the same Plan Year, then it shall be treated as if it were never adopted, unless the Plan amendment provides otherwise.

(e) Notice Requirement. Written notice to Participants and Beneficiaries shall be provided within 30 days, in accordance with section 101(j) of ERISA, if the Plan becomes subject to a limitation described in subparagraph (a)(1), (b), or (c) of this Section.

(f) Methods to Avoid or Terminate Benefit Limitations. Application of one or more of the benefit limitations set forth in paragraphs (a), (b) and (c) of this Section for a Plan Year may be avoided or terminated through the use of employer contributions, by increasing the amount of Plan assets which are taken into account in determining the adjusted funding target attainment percentage and by other methods in accordance with sections 436(b)(2), (c)(2), (e)(2) and (f) of the Code and Treasury Regulation section 1.436-1(f).

(g) Plan Operations for Periods Prior to and After Certification of Plan's Adjusted Funding Target Attainment Percentage .

(1) In General. For any period during which a presumption under section 436(h) of the Code and Treasury Regulation section 1.436-1(h) applies to the Plan, the limitations under paragraphs (a) through (c) of this Section are applied to the Plan as if the adjusted funding target attainment percentage for the Plan Year were the presumed adjusted funding target attainment percentage determined under the rules of section 436(h) of the Code and Treasury Regulation section 1.436-1(h)(1), (2), or (3). These presumptions are set forth in subparagraphs (g)(2) though (g)(4) below.

(2) Presumption of Continued Underfunding Beginning First Day of Plan Year. If a limitation under paragraph (a), (b) or (c) of this Section applied to the Plan on the last day of the preceding Plan Year, then, commencing on the first day of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g)(3) or (g)(4) below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the adjusted funding target attainment percentage in effect on the last day of the preceding Plan Year; and

(ii) The first day of the current Plan Year is a section 436 measurement date.

(3) Presumption of Underfunding Beginning First Day of Fourth Month. If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the fourth month of the Plan Year and the Plan's adjusted funding target attainment percentage for the preceding Plan Year was either at least 60% but less than 70% or at least 80% but less than 90%, or is described in Treasury Regulation section 1.436-1(h)(2)(ii), then, commencing on the first day of the fourth month of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g)(4) below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the Plan's adjusted funding target attainment percentage for the preceding Plan Year reduced by 10 percentage points; and

(ii) The first day of the fourth month of the current Plan Year is a section 436 measurement date.

(4) Presumption of Underfunding On and After First Day of 10th Month . If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the 10th month of the Plan Year (or if the Plan's enrolled actuary has issued a range certification for the Plan Year pursuant to Treasury Regulation section 1.436-1(h)(4)(ii) but has not issued a certification of the specific adjusted funding target attainment percentage for the Plan by the last day of the Plan Year), then, commencing on the first day of the 10th month of the current Plan Year and continuing through the end of the Plan Year:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be less than 60%; and

(ii) The first day of the 10th month of the current Plan Year is a section 436 measurement date.

(h) Plan Termination and Other Special Rules.

(1) Plan Termination. The limitations on prohibited payments in subparagraphs (a)(1), (b)(1), and (c) of this Section do not apply to prohibited payments that are made to carry out the termination of the Plan in accordance with applicable law. Any other limitations under this Section do not cease to apply as a result of termination of the Plan.

(2) Special Rules Relating to Unpredictable Contingent Event Benefits and Plan Amendments Increasing Benefit Liability . During any period in which none of the presumptions under paragraph (g) of this Section apply to the Plan and the Plan's enrolled actuary has not yet issued a certification of the Plan's adjusted funding target attainment percentage for the Plan Year, the limitations under subparagraphs (a)(2) and (b)(2) of this Section shall be based on the "inclusive presumed adjusted funding target attainment percentage" for the Plan, as such term is described in, and calculated in accordance with the rules of, Treasury Regulation section 1.436-1(g)(2)(iii).

(3) Payments Under Social Security Leveling Options. For purposes of determining whether the limitations under subparagraph (a)(1) or (b)(1) of this Section apply to payments under a social security leveling option, within the meaning of section 436(j)(4)(C)(i) of the Code, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under section 436(j)(3) of the Code and any Treasury Regulations or other published guidance thereunder issued by the Internal Revenue Service.

(4) Limitation on Benefit Accruals. For purposes of determining whether the accrual limitation under subparagraph (b)(3) of this Section applies to the Plan, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under section 436 of the Code (except as provided under section 203(b) of the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010, if applicable).

(5) Interpretation of Provisions. The limitations imposed by this Section shall be interpreted and administered in accordance with section 436 of the Code and Treasury Regulation section 1.436-1.

(i) Definitions. The definitions in the following Treasury Regulations apply for purposes of this Section: section 1.436-1(j)(1) defining adjusted funding target attainment percentage; section 1.436-1(j)(2) defining annuity starting date; section 1.436-1(j)(6) defining prohibited payment; section 1.436-1(j)(8) defining section 436 measurement date; and section 1.436-1(j)(9) defining an unpredictable contingent event and an unpredictable contingent event benefit.

(j) Effective Date. The rules in this Section are effective for Plan Years beginning after December 31, 2009.

ARTICLE 9
SPECIAL PARTICIPATION AND DISTRIBUTION RULES RELATING TO RECOMMENCEMENT OF EMPLOYMENT AND EMPLOYMENT BY RELATED ENTITIES

Section 9.1 Recommencement of Employment by a Terminated Employee. (a) Rehire Date Before Absence of 5 Years. If an Employee who has a Termination of Employment recommences employment with an Employer before having a Period of Severance of five years and, on the date of his or her rehire, the terms of such Employee's employment are not subject to a collective bargaining agreement that does not provide for participation in this Plan, then either: (1) if such Employee was a Participant on the date his or her employment terminated, such Employee shall be Participant in the Plan as of his or her rehire date if he or she is then an Eligible Employee or (2) if such Employee was not a Participant on the date his or her employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant. Notwithstanding clause (1) of the preceding sentence, if an Employee described in the preceding sentence who first became an employed by an Employer prior to January 1, 2001 was not at any time permitted to make the election described in Section 3.1(b) (relating to eligibility for participation for employees who are not new hires) or was permitted to make such election and elected to participate in the Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the ComEd Plan or the PECO Plan, as applicable, at the time prescribed therein and have his or her accrued benefit under the ComEd Plan or PECO Plan, as applicable, and related assets transferred to the Plan in the manner described in Section 3.1(c) (relating to transfer of benefits and assets to Plan). If an Employee makes the election described in clause (1) of the preceding sentence, (a) the applicable Schedule shall apply with respect to the Participant's Accrued Frozen Benefit and (b) such Employee shall not be entitled to a Transition Credit.

(b) Rehire Date After Absence of at Least 5 Years. If a Participant who has a vested benefit under the Plan has a Termination of Employment and thereafter is rehired by an Employer, such Participant shall remain a Participant upon his or her rehire. If an Employee who has a Termination of Employment did not have a vested benefit under the Plan or under either the ComEd Plan or the PECO Plan recommences employment with an Employer after having a Period of Severance of at least five years, such Employee shall become a Participant as of the date of his or her rehire if he or she is then an Eligible Employee. If an Employee who has a Termination of Employment had a vested benefit under either the ComEd Plan or the PECO Plan recommences employment with an Employer after having a Period of Severance of at least five years, such Employee shall not be an Eligible Employee and shall not become a Participant upon such recommencement of employment. Notwithstanding the preceding sentence, if an Employee described in the preceding sentence who first became employed by an Employer prior to January 1, 2001 was not at any time permitted to make the election described in Section 3.1(b) (relating to eligibility for participation for employees who are not new hires) or was permitted to make such election and elected to participate in the Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the ComEd Plan or the PECO Plan, as applicable, at the time prescribed therein and have his or her accrued benefit under the ComEd Plan or PECO Plan, as applicable, transferred to the Plan in the manner described in Section 3.1(c) (relating to transfer of benefits and assets to Plan). The accrued benefit under the ComEd Plan or the PECO Plan, as applicable, of an Employee who elects to participate in the Plan shall be transferred to the Plan, along with an appropriate amount of assets, and (a) the applicable Schedule shall apply with respect to the Participant's Accrued Frozen Benefit and (b) such Employee shall not be entitled to a Transition Credit.

(c) Reestablishment of Cash Balance Account for Rehired Participant . If a Participant whose Termination of Employment occurs before his or her satisfaction of the Vesting Requirement recommences employment with an Employer and becomes a Participant pursuant to paragraph (a) above, such Participant's Cash Balance Account shall be reinstated and credited with Investment Credits for the Participant's Period of Severance. If a Participant whose Termination of Employment occurs after his or her satisfaction of the Vesting Requirement receives a complete distribution of his or her benefit under the Plan and subsequently recommences employment with an Employer as an Employee and becomes a Participant pursuant to paragraph (b) above, a new Cash Balance Account shall be established for such Participant as of such recommencement of employment. Such new Cash Balance Account shall have an initial balance of zero and shall be credited with Service Credits and Investment Credits solely for the Participant's period of employment thereafter.

Section 9.2 Suspension of Benefits. (a) Generally. If a Participant continues employment by an Employer beyond the Participant's Normal Retirement Age or, except as provided in paragraph (b) below, if a former Employee again becomes an Employee after his or her Normal Retirement Age, such Participant shall not be entitled to receive any Pension during such employment. If such a Participant was receiving a Pension, the Participant's Cash Balance Account as of his or her Pension Starting Date shall be restored and thereafter credited with Service Credits and Investment Credits with respect to such period of employment and Investment Credits from the Participant's prior Pension Starting Date to the date the Participant's Cash Balance Account is so restored. Upon the Participant's Termination of Employment or subsequent Termination of Employment, as the case may be, the Participant's Accrued Benefit shall be the larger of (i) the Participant's Accrued Benefit as of the first day of the month coinciding with or next following the Participant's date of rehire, or Normal Retirement Age, as the case may be, actuarially increased to reflect the later termination date (for purposes of this clause (i), the Investment Credits described in Section 6.1(d) with respect to such period of employment shall be the actuarial increase to the Participant's Accrued Benefit), and (ii) the Actuarial Equivalent of the Participant's Cash Balance Account, and the Accrued Frozen Benefit, as of the Participant's Termination of Employment, or subsequent Termination of Employment, as the case may be, reduced in either case by the sum of any Pension previously paid to the Participant plus interest thereon at the rate described in subdivision (3) of Article 2 (relating to definition of Actuarial Equivalent).

(b) Circumstances under which a Rehired Employee's Pension Payments may Continue . Notwithstanding paragraph (a) above, a reemployed Participant who is employed under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees shall not have his or her Pension suspended under this Section nor shall such reemployed Participant be prohibited from commencing his or her Pension if he or she is otherwise eligible to commence such Pension.

Section 9.3 Employment by Related Entities. If an individual is employed by an entity that is an Affiliate, then any period of employment by such entity (but only after such entity became an Affiliate) shall be taken into account solely for the purpose of determining when or whether and when such individual is eligible to participate in the Plan under Article 3 (relating to eligibility), measuring such individual's years of Vesting Service for purposes of the Vesting Requirement and determining when such individual's Termination of Employment occurs for purposes of Article 7 (relating to distributions) to the same extent such period would have been taken into account had such employment been with an Employer.

Section 9.4 Leased Employees. If an individual who performed services as a leased employee (within the meaning of section 414(n)(2) of the Code) of an Affiliate becomes an Employee, or if an Employee becomes such a leased employee, then any period as a leased employee shall be taken into account solely for the purposes of determining whether and when such individual is eligible to participate in the Plan under Article 3 (relating to eligibility), measuring such individual's years of Vesting Service for purposes of the Vesting Requirement and determining when such individual's Termination of Employment occurs for purposes of Article 7 (relating to distributions) to the same extent such period would have been taken into account had such service or employment been with an Employer. In addition, any contributions or benefits provided under another plan to such leased employee by his or her leasing organization shall be treated as provided under this Plan and shall be taken into account under Section 8.1 (relating to statutory limits) to the extent required under Treasury Regulation section 1.415(a)-1(f)(3). This Section shall not apply to any period during which such a leased employee was covered by a plan described in section 414(n)(5) of the Code and leased employees do not constitute more than 20% of the Employer's nonhighly compensated work force. Notwithstanding the preceding sentences, an individual who performed services only as a leased employee prior to January 1, 2001 shall be treated as not performing an Hour of Service prior to January 1, 2001 solely for the purposes of determining whether such individual qualifies as an Eligible Employee under subdivision (16) of Article 2.

Section 9.5 Employees who Become Eligible Employees as a Result of Ceasing to be Represented by IBEW Local Union 15 . If an Employee who, on the day he or she first performed an Hour of Service with an Employer, was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer prior January 1, 2001 later ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (a) continue to participate in the ComEd Plan or (b) participate in this Plan as of the date he or she ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15 and have his or her accrued benefit under the ComEd Plan and related assets transferred to the Plan in the manner described in Section 3.1(c) (relating to transfer of benefits and assets to Plan). If an Employee who, on the day he or she first performed an Hour of Service with an Employer, was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer on or after January 1, 2001 and participated in the Exelon Corporation Pension Plan for Bargaining Unit Employees later becomes an Eligible Employee as a result of ceasing to be a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall become a Participant as of the date he or she ceases to be a member of a collective bargaining unit represented by IBEW Local

Union 15 and shall have his or her accrued benefit under the Exelon Corporation Pension Plan for Bargaining Unit Employees and related assets transferred to the Plan. If an Employee who, on the day he or she first performed an Hour of Service with an Employer, was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer on or after January 1, 2001 and who was a participant in the Commonwealth Edison Company Service Annuity System later becomes a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall not become a Participant in this Plan.

Section 9.6 Employees who Cease to be Eligible Employees as a Result of Becoming Represented by IBEW Local Union 15 . If an Employee ceases to be an Eligible Employee as a result of becoming a member of a collective bargaining unit represented by IBEW Local Union 15 and becomes a participant in the Exelon Corporation Pension Plan for Bargaining Unit Employees or the Commonwealth Edison Company Service Annuity System, such Employee shall have his or her accrued benefit under this Plan and related assets transferred to the applicable plan.

Section 9.7 Change in Employment Status or Transfer to Affiliate . Except as otherwise provided in Section 9.8 and elsewhere in the Plan, if an Employee who was a Participant transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead either eligible to participate in another plan maintained by such Employer or Affiliate or are not eligible to participate in any plan, then such individual shall upon such transfer or reemployment participate in the plan, if any, determined pursuant to rules established by the Company, which rules may be set forth in a Supplement hereto.

Section 9.8 Transfer of Employment to or from Facilities formerly Owned by CEG . Effective as of the Effective Time (as such term is defined in the Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code (each such plan, a "CEG Pension Plan") , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Pension Plan. If a participant in the CEG Pension Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Pension Plan and shall not participate in the Plan.

ARTICLE 10
ADMINISTRATION

Section 10.1 The Administrator, the Investment Office and the Corporate Investment Committee .

(a) The Administrator. The Company's Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the

Administrator shall be the “named fiduciary” of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan’s assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan. The determination of the Administrator with respect to an Employee’s years of Vesting Service, the amount of the Employee’s Compensation, and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his or her discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his or her duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust Fund under Article 7 (relating to distributions). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Participants, the amounts of all Pensions, the dates of death of Participants and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Pension to be paid out of the Trust Fund.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan’s agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator. The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

(c) The Investment Office. The Investment Office, shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in section 404(a)(2) of ERISA and all other applicable limitations. The Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Trust Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Office.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

(d) The Corporate Investment Committee. The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Office and shall review annual manager review results and any other reports and documents submitted by the Investment Office.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Office, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Office.

(iii) The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the Investment Office and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

(e) Status of Administrator, the Investment Office and the Corporate Investment Committee. The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

(f) Notice to Trustee of Members. The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

(g) Allocation of Responsibilities. Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

(h) General Governance. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

(i) Indemnification. The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

(j) No Compensation. None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

(k) Employ of Counsel and Agents. The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

Section 10.2 Claims Procedure. Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Section 13.11 (relating to statute of limitations for actions under the Plan) and 13.12 (relating to forum for legal actions under the Plan)) to bring a civil action under section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to the officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

Section 10.3 Notices to Participants, Etc. All written notices, reports and statements given, made, delivered or transmitted to a Participant or Beneficiary or any other person entitled to or claiming benefits under the Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or Beneficiary or such other person at the address last appearing on the records of the Administrator. A Participant or Beneficiary or other person may record any change of his or her address from time to time by written notice filed with the Administrator.

Section 10.4 Responsibility to Advise Administrator of Current Address. Each person entitled to receive a payment under the Plan shall file with the Administrator in writing his or her complete mailing address and each change therein. A check or communication mailed to any person at his or her address on file with the Administrator shall be deemed to have been received by such person for all purposes of the Plan, and neither the Administrator, the Employers nor the Trustee shall be obliged to search for or ascertain the location of any person. If the Administrator shall be in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his or her last address known to the Administrator, notify such person that all future Pension payments will be withheld until such person submits to the Administrator evidence of his or her continued life and his or her proper mailing address.

Section 10.5 Notices to Employers or Administrator. Written directions, notices and other communications from Participants or Beneficiaries or any other persons entitled to or claiming benefits under the Plan to the Employers or the Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the form prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

Section 10.6 Responsibility to Furnish Information and Sign Documents . Each person entitled to a payment under the Plan shall furnish such information and data, including birth certificates or other evidence of age satisfactory to the Administrator, and sign such documents as may reasonably be requested by the Administrator or the Trustee in connection with the administration of the Plan.

Section 10.7 Records. Each of the Administrator, the Investment Office and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account, records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

Section 10.8 Actuary to be Employed. The Company or the Investment Office shall engage an actuary to do such technical and advisory work as the Company or the Investment Office may request, including analyses of the experience of the Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Office of an annual actuarial report, which report shall contain information showing the financial condition of the Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Office.

Section 10.9 Funding Policy. The Company shall establish a funding policy and method consistent with the objectives of the Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Office.

Section 10.10 Electronic Media. Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

Section 10.11 Correction of Error. If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

ARTICLE 11
PARTICIPATION BY OTHER EMPLOYERS

Section 11.1 Adoption of Plan. With the consent of the Company, any entity may become a participating Employer under the Plan with respect to all or a designated group of its employees by taking such action as shall be necessary or desirable to adopt the Plan and executing and delivering such instruments as may be necessary or desirable to put the Plan into effect with respect to such entity.

Section 11.2 Withdrawal from Participation. Any Employer shall terminate its participation in the Plan at any time, under such circumstances as the Company may provide, by delivering to the Company a duly certified copy of a resolution of its board of directors (or other governing body) to that effect, or by ceasing to be a member of the same controlled group as the Company (within the meaning of section 1563(a) of the Code).

Section 11.3 Company and Administrator as Agent for Employers . Each entity which shall become a participating Employer pursuant to Section 11.1 (relating to adoption of the Plan) or Article 12 (relating to continuance by a successor) by so doing shall be deemed to have appointed the Company and the Administrator its agent to exercise on its behalf all of the powers and authorities hereby conferred upon the Company and the Administrator by the terms of the Plan, including, but not by way of limitation, the power to amend and terminate the Plan. The authority of the Company and the Administrator to act as such agent shall continue unless and until the portion of the Trust held for the benefit of Employees of the particular Employer and their Beneficiaries is set aside in a separate trust as provided in Section 15.2 (relating to establishment of separate plan).

ARTICLE 12
CONTINUANCE BY A SUCCESSOR

In the event that an Employer is reorganized by way of merger, consolidation, transfer of assets or otherwise, so that another entity succeeds to all or substantially all of the Employer’s business, such successor entity may be substituted for the Employer under the Plan by adopting the Plan and becoming a party to the Trust agreement. If, within 90 days following the effective date of any such reorganization, such successor entity shall not have elected to become a party to the Plan, or if the Employer adopts a plan of complete liquidation other than in connection with a reorganization, the Plan shall be automatically terminated with respect to Employees of such Employer as of the close of business on the 90th day following the effective date of such reorganization or as of the close of business on the date of adoption of such plan of complete liquidation, as the case may be. If such successor entity is substituted for the Employer by electing to become a party to the Plan as described above, then, for all purposes of the Plan, employment with such successor entity and compensation paid by such successor entity shall be considered to be employment with, and Compensation paid by, an Employer.

ARTICLE 13
MISCELLANEOUS

Section 13.1 Expenses. The expenses of the Trustee in the administration of the Trust Fund, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Trust Fund, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan or the Trust Fund, as applicable, including, but not limited to, "direct expenses" incurred in administering the Plan and the Trust Fund (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust Fund), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Trust Fund, as applicable, shall be paid by the Trustee from the Trust Fund in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Notwithstanding the foregoing, the Administrator or the Investment Office may authorize an Employer to act as an agent of the Plan to pay any expenses, and the Employer shall be reimbursed from the Trust Fund for such payments.

Section 13.2 Non-Assignability. (a) In General. It is a condition of the Plan, and all rights of each Participant and Beneficiary shall be subject thereto, that no right or interest of any Participant or Beneficiary in the Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not limited to, by way of limitation, execution, levy, garnishment, attachment, pledge or bankruptcy, but excluding devolution by death or mental incompetency, and no right or interest of any Participant or Beneficiary in the Plan shall be liable for, or subject to, any obligation or liability of such Participant or Beneficiary, including claims for alimony or the support of any Spouse.

(b) Exception for Qualified Domestic Relations Orders. Notwithstanding any provision of the Plan to the contrary, if a Participant's Accrued Benefit under the Plan, or any portion thereof, shall be the subject of one or more Qualified Domestic Relations Orders, such Accrued Benefit or portion thereof shall be paid to the person and at the time and in the manner specified in any such order. The Administrator or its agent, in its sole discretion, shall determine whether any order constitutes a Qualified Domestic Relations Order under this paragraph (b). A domestic relations order shall not fail to constitute a Qualified Domestic Relations Order under this paragraph (b) solely because such order provides for immediate payment to an alternate payee of the portion of the Participant's Accrued Benefit assigned to the alternate payee under the terms of such order.

Section 13.3 Employment Non-Contractual. Neither this Plan nor any action taken by the Administrator or the Investment Office confers any right upon an Employee to continue in employment with any Employer.

Section 13.4 Limitation of Rights. A Participant or distributee shall have no right, title or claim in or to any specific asset of the Trust Fund, but shall have the right only to distributions from the Trust Fund on the terms and conditions he or she herein provided. Neither this Plan nor any action taken by the Administrator or the Investment Office shall obligate any Employer to make contributions to the Trust in excess of the contributions authorized by the board of directors of the Company or create any liability on an Employer for the payment of Pensions under this Plan.

Section 13.5 Merger or Consolidation with Another Plan. A merger or consolidation with, or transfer of assets or liabilities to, any other plan shall not be effected unless the terms of such merger, consolidation or transfer are such that each Participant, distributee, Beneficiary or other person entitled to receive benefits from the Plan would, if the Plan were to terminate immediately after the merger, consolidation or transfer, receive a benefit equal to or greater than the benefit such person would be entitled to receive if the Plan were to terminate immediately before the merger, consolidation, or transfer.

Section 13.6 Construction. (a) General. Wherever used in the Plan, words in the masculine gender shall include masculine or feminine gender, and, unless the context otherwise requires, words in the singular shall include the plural, and words in the plural shall include the singular. All references to employment or the rehire or termination thereof shall refer to employment by any and all Employers, and to the extent provided herein, and, to the extent required by Section 3.2 (relating to transfers to affiliates) and Section 9.3 (relating to employment by related entities), any and all Affiliates, unless the context requires otherwise.

(b) Definition of "Highly Compensated Employee". Wherever applicable for purposes of satisfying legal requirements applicable to the Plan, the term "highly compensated employee" shall mean any Employee who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q)(1)(B)(ii) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its Affiliates when ranked on the basis of compensation paid during such preceding Plan Year.

Section 13.7 Applicable Law. Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

Section 13.8 Severability. If a provision of the Plan shall be held illegal or invalid, the illegality or invalidity shall not affect the remaining parts of the Plan and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included in the Plan.

Section 13.9 No Guarantee. None of the Administrator, the Investment Office, the Corporate Investment Committee, the Employers, nor the Trustee in any way guarantees the Trust from loss or depreciation nor the payment of any money that may be or become due to any person from the Trust Fund or pursuant to the Plan. Nothing herein contained shall be deemed to give any Participant, distributee, or Beneficiary an interest in any specific part of the Trust Fund or any other interest, right or claim except the right to receive benefits out of the Trust Fund in accordance with the provisions of the Plan and the Trust Fund.

Section 13.10 Military Service. Notwithstanding any provision of the Plan to the contrary, contributions, benefits and Service with respect to Military Service shall be provided in accordance with section 414(u) of the Code.

Section 13.11 Statute of Limitations for Actions under the Plan . Except for actions to which the statute of limitations prescribed by section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

Section 13.12 Forum for Legal Actions under the Plan . Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

Section 13.13 Legal Fees. Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, any member of the Exelon Investment Office, any member of the Corporate Investment Committee, the Chief Human Resources Officer, any Plan fiduciary, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE 14
TOP-HEAVY PLAN REQUIREMENTS

Section 14.1 Top-Heavy Plan Determination. If as of the determination date (as hereinafter defined) for any Plan Year the aggregate present value of (i) the accrued benefits under the Plan and under all other defined benefit plans in the aggregate group (as hereinafter defined) and (ii) the aggregate account balances under all defined contribution plans in such aggregation group, in each case with respect to all participants in such plans who are key employees (as defined in section 416(i) of the Code) for such Plan Year, exceeds 60% of the aggregate present value of accrued benefits and the account balances of all participants in all such plans as of the determination date, then the Plan shall be a top-heavy plan for such Plan

Year and the requirements of Sections 14.3 (relating to minimum benefits for top-heavy years) and 14.4 (relating to top-heavy vesting requirements) shall be applicable for such Plan Year as of the first day thereof. If the Plan shall be a top-heavy plan for any Plan Year, such requirements shall not be applicable for such subsequent Plan Year except to the extent provided in Section 14.3 (relating to minimum benefits for top-heavy years).

Section 14.2 Definitions and Special Rules. (a) Definitions. For purposes of this Article, the following definitions shall apply:

(i) Determination Date. The determination date for all plans in the aggregation group shall be the last day of the preceding plan year, and the valuation date applicable to a determination date shall be (a) in the case of a defined contribution plan, the date as of which account balances are determined that is coinciding with or immediately precedes the determination date, and (b) in the case of a defined benefit plan, the date as of which the most recent actuarial valuation for the plan year that includes the determination date is prepared, except that if any such plan specifies a different determination or valuation date, such different date shall be used with respect to such plan.

(ii) Aggregation Group. The aggregation group shall consist of (a) each plan of an Employer in which a key employee is a participant, (b) each other plan that enables such a plan to be qualified under section 401(a) of the Code, and (c) any other plans of an Employer that the Company designates as part of the aggregation group.

(iii) Key Employee. Key employee shall have the meaning set forth in section 416(i) of the Code.

(iv) Top-Heavy Compensation. Top-heavy compensation shall have the meaning set forth in section 1.415(c)-2 of the Treasury Regulations.

(b) Special Rules. For the purpose of determining the accrued benefit or account balance of a participant, the accrued benefit or account balance of any person who has not been actively at work with an Employer at any time during the one-year period ending on the determination date shall not be taken into account pursuant to this Section, and any person who received a distribution from a plan (including a plan that has terminated) in the aggregation group during the one-year period ending on the determination date shall be treated as a participant in such plan, and any such distribution shall be included in such participant's account balance or accrued benefit, as the case may be; provided, however, that in the case of a distribution made for a reason other than a Participant's severance from employment, death or disability, this sentence shall be applied by substituting "five-year period" for "one-year period".

Section 14.3 Minimum Benefit for Top-Heavy Years. (a) The Pension to which a Participant is entitled at Normal Retirement Age under Section 7.2 (relating to form of distribution) shall in no event be less than two percent of the Participant's highest average compensation (as hereinafter defined) multiplied by the number of the Participant's years of Vesting Service, determined as provided below, not in excess of ten. For purposes of this Section, (i) a Participant's years of Vesting Service shall mean his or her years of Vesting Service but excluding any year of Vesting Service completed in a Plan Year for which the Plan was not a top-heavy plan, and (ii) a Participant's highest average compensation shall be the annual average of his or her top heavy compensation for the period of consecutive calendar years not exceeding 5 during which the Participant's top heavy compensation was the greatest, except that calendar years after the last Plan Year for which the Plan was top-heavy shall be disregarded.

(b) The provisions of paragraph (a) of this Section shall not apply with respect to a Participant if, for each year in which the Plan is a top-heavy plan, (i) the eligible employee's Employer also maintains a defined contribution plan which is included in the aggregation group for such year and (ii) under such plan, contributions made and forfeitures allocated to each eligible employee (other than key employees) equal 5% of such Participant's top heavy compensation for each Plan Year the Plan is top-heavy.

Section 14.4 Top-Heavy Vesting Requirements. If a Participant's Termination of Employment shall occur during a Plan Year for which a Plan is a top-heavy plan as defined in section 416(i) of the Code and after the Participant shall have completed at least three years of Vesting Service, the Participant shall be deemed to have satisfied the Vesting Requirement and shall be entitled to the Pension described in Section 7.2 (relating to form of distribution).

ARTICLE 15
AMENDMENT, ESTABLISHMENT OF SEPARATE PLAN AND TERMINATION

Section 15.1 Amendment. The board of directors of the Company (or a committee thereof) may at any time and from time to time amend or modify this Plan in any manner deemed by the board of directors of the Company to be necessary or desirable, provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater. Any such amendment or modification shall become effective on such date as the board (or committee thereof) or executive shall determine and may apply to Participants in this Plan at the time thereof as well as to future Participants, provided, however, that, unless permitted by applicable law, no such amendment or modification which reduces the basis for the computation of Pensions shall be retroactive as to service prior to the date of such amendment or modification.

Section 15.2 Establishment of Separate Plan. If an Employer shall withdraw from this Plan under Section 11.2 (relating to withdrawal from participation), the Investment Office shall determine the portion of the Trust Fund held by the Trustee which is applicable to the Participants of such Employer and direct the Trustee to segregate such portion in a separate trust. Such separate trust shall thereafter be held and administered as a part of the separate plan of such Employer.

Section 15.3 Termination of the Plan by an Employer. The Company may at any time, by resolution adopted by its board of directors, terminate this Plan in its entirety. In addition, any Employer may at any time terminate its participation in this Plan by resolution adopted by its board of directors to that effect. Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that this Plan and the Trust Fund as adopted by the Company meets the requirements of section 401(a) of the Code and that the Trust Fund is exempt from tax under section 501(a) of the Code, and if the Internal Revenue Service shall refuse to issue such letter, any Employer may terminate its participation in this Plan and direct the Trustee to pay and deliver to that Employer the portion of the Trust Fund applicable to its contributions.

Section 15.4 Vesting and Distribution Upon Termination or Partial Termination. Upon termination or partial termination of the Plan, the benefit as of the date of termination or partial termination, as the case may be, of all affected Participants shall be fully vested; provided, however, that full vesting shall be required with respect to a termination or partial termination only to the extent the Plan is then funded.

Allocation and distribution of the terminated portion of the Trust Fund shall thereafter be made in accordance with the applicable requirements of ERISA and the Code and with any applicable approval of the Pension Benefit Guaranty Corporation (the “PBGC”). If the

Administrator is notified by PBGC that PBGC is unable to determine that the Trust Fund is sufficient to discharge when due all obligations of the Plan with respect to benefits guaranteed by PBGC pursuant to section 4022 of ERISA, then the allocation and distribution of such portion of the Trust Fund shall be made only under the direction of PBGC or a United States district court pursuant to section 4044 of ERISA.

In the event that, after the termination of the Plan, any assets remain after such allocation, such assets shall be paid to the Company. The portion of the assets allocated to provide benefits to any person or group of persons may be applied for the benefit of such person or persons by the distribution of cash, continuance of the Trust Fund, establishment of a new Trust Fund, purchase of annuities from an insurance company, or otherwise, as determined by the Investment Office in its sole discretion; provided, however, that the benefit of any Participant or former Participant who is married and has satisfied the Vesting Requirement shall, unless such person shall elect otherwise, be paid in the form set forth in Section 7.2(b) (relating to manner of distribution with respect to married Participants) and, if the surviving Spouse of a deceased Participant or deceased former Participant is entitled to receive a benefit pursuant to Section 7.2(b) (relating to manner of distribution with respect to married Participants) or Section 7.3 (relating to pre-retirement death benefits), as the case may be, such benefit shall, unless such person shall elect otherwise, be paid in the form set forth therein.

Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that the Plan and Trust Fund as adopted by the Company meet the requirements of section 401(a) of the Code and that the Trust Fund is exempt from tax under section 501(a) of the Code, and, in the event that the Internal Revenue Service shall refuse to issue such letter, the Company may terminate the Plan and shall direct the Trustee to pay and deliver the Trust Fund to the Company.

Section 15.5 Trust Fund to Be Applied Exclusively for Participants and Their Beneficiaries . Subject only to the provisions of Section 4.2 (relating to limitation on contributions) and 15.4 (relating to vesting and distribution upon termination or partial termination), and any other provision of the Plan to the contrary notwithstanding, it shall be impossible for any part of the Trust Fund to be used for or diverted to any purpose not for the exclusive benefit of Participants and their beneficiaries and the payment of expenses in accordance with Section 13.1 (relating to expenses) either by operation or termination of the Plan, power of amendment or otherwise.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officer on this _______ day of December, 2013.

EXELON CORPORATION

By: ______________________________

Amy E. Best
Senior Vice President and
Chief Human Resources Officer

Exhibit A

Incentive Pay Plans

Exelon Corporation Annual Incentive Award Plan (or the equivalent cash incentive award program applicable to employees in salary band VII or higher)

Exelon Corporation Quarterly Incentive Award Program

Appendix I

List of Employers

Table T

Transition Credit Factors

Age on 12/31/2001	Percentage	Age on 12/31/2001	Percentage
<31	2.0	41	4.6
31	2.4	42	4.7
32	2.8	43	4.8
33	3.2	44	4.9
34	3.6	45	5.0
35	4.0	46	5.2
36	4.1	47	5.4
37	4.2	48	5.6
38	4.3	49	5.8
39	4.4	50+	6.0
40	4.5		

SCHEDULE A

PROVISIONS APPLICABLE TO
ACCRUED FROZEN BENEFIT
UNDER THE COMMONWEALTH EDISON COMPANY
SERVICE ANNUITY SYSTEM

1. APPLICATION

This Schedule shall apply only to a Participant who elects to participate in the Plan pursuant to Section 3.1(b) of the Plan (relating to eligibility for participation for employees other than new hires) or Section 9.1 of the Plan (relating to recommencement of employment by terminated employee) and whose accrued benefit under the ComEd Plan is transferred to the Plan pursuant to Section 3.1(c) of the Plan (relating to transfer of benefits and assets to Plan) or Section 9.1 of the Plan. The provisions of this Schedule shall govern with respect to all matters relating to such a Participant's Accrued Frozen Benefit.

2. DEFINED TERMS

For purposes of this Schedule A, capitalized terms used herein shall have their respective meanings set forth in the Plan, except that the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Accrued Frozen Benefit. The amount payable with respect to a Participant's accrued benefit under the ComEd Plan determined as of December 31, 2001 commencing on the first day of the month coinciding with or next following a Participant's Schedule A Normal Retirement Age, determined as if such amount were payable in the form of a single life annuity for the life of the Participant.

B. Child. A Participant's natural child born prior to the Participant's Pension Starting Date or a child adopted by a Participant prior to the Participant's Pension Starting Date.

C. Consumer Price Index. The United States Bureau of Labor Statistics Consumer Price Index (U.S. City Average 1967 = 100). Such term shall also mean such index as it may from time to time be changed or, if it shall be discontinued, the most nearly comparable index, appropriately adjusted to yield results comparable with those which would have been produced if the index as defined in the preceding sentence had been used, as determined by the Investment Office.

D. Credited Service. A Participant's Credited Service includes the Participant's "credited service" as of the date he or she becomes a Participant, determined in accordance with the provisions of the ComEd Plan as in effect on such date, and the period beginning on the date the Participant becomes a Participant during which the Participant shall have been an Employee, including, (a) any period during which the Participant is in Military Service, provided that the Participant returns to the employ of an Employer within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (b) any period for which back pay is awarded to the Participant and pursuant to which award the Participant is required to receive credited service under the Plan, (c) the period following Termination of Employment on account of a total and permanent disability during which the Participant is receiving benefits under any Employer's long term disability plan and (d) as and to the extent provided by resolutions of the board of directors of the Company, (i) any period of employment by Affiliates or other companies, and (ii) any period of authorized absence from such employment or from employment as an Eligible Employee. A Participant's periods of Credited Service before and after a Period of Severance that is not included in the Participant's Credited Service pursuant to the preceding sentences shall be aggregated only if (i) the Participant completes at least one year of Credited Service after such period of absence and (ii) the number of years of such Period of Severance is less than five.

E. Dependent Minor Child. A Child who, as of the time of the Participant's retirement or death, is under the age of 21 and qualifies as a dependent of the Participant within the meaning of Section 152 of the Code.

F. Dependent Disabled Child. A Child who, as of the time of the Participant's retirement or death, has a permanent physical or mental disability, as certified by the medical director of the Company or by such other licensed physician designated by the Administrator, that causes such Child to be unable to engage in substantial gainful employment, and is a dependent of the Participant within the meaning of Section 152 of the Code (determined by disregarding any age limitation contained in Section 152 of the Code).

G. Early Retirement Date. The date on which a Participant completes at least ten years of Credited Service and attains at least age 50.

H. Schedule A Actuarial Factors. The table specified by the Commissioner of Internal Revenue for purposes of section 417(e)(3) of the Code (which, as of the Effective Date, is the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female)) in effect on the date a determination hereunder occurs and an interest rate assumption using the "applicable interest rate" as defined in section 417(e)(3) of the Code for the month of November of the Plan Year immediately preceding the Plan Year in which a determination hereunder occurs.

I. Schedule A Normal Retirement Age. A Participant's 65th birthday.

3. SPECIAL RULES REGARDING COMPUTATION OF BENEFIT

A. Factors to Calculate Pension Paid Before Schedule A Normal Retirement Age

1. Pension Starting Date on or After Early Retirement Date and Prior to Schedule A Normal Retirement Age . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Early Retirement Date and whose Pension commences prior to his or her Schedule A Normal Retirement Age shall be computed by multiplying such Participant's Accrued Frozen Benefit by the applicable factor from Table B-1.

2. Pension Starting Date After Attainment of Age 60 but Prior to Early Retirement Date . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs on or after such Participant's attainment of age 60 but prior to such Participant's attainment of his or her Early Retirement Date shall be such Participant's Accrued Frozen Benefit without any actuarial reduction.

3. Pension Starting Date After Completion of Ten Years of Credited Service but Prior to Attainment of Age 60 . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs prior to such Participant's attainment of age 60 and prior to his or her attainment of his or her Early Retirement Date, but after the Participant has completed at least ten years of Credited Service, shall be (a) if the Participant's Pension Starting Date occurs on or after his or her attainment of age 50, the amount determined by multiplying such Participant's Accrued Frozen Benefit by the applicable factor in Table F and (b) if the Participant's Pension Starting Date occurs prior to his or her attainment of age 50, the amount determined by actuarially reducing the Participant's Accrued Frozen Benefit using the factors in Table F to reduce the Accrued Frozen Benefit from age 60 to age 50 and using the Schedule A Actuarial Factors to reduce the Accrued Frozen Benefit to the Participant's Pension Starting Date.

4. Pension Starting Date Prior to Attainment of Age 60 and Prior to Completion of Ten Years of Credited Service . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs prior to such Participant's attainment of age 60 and prior to such Participant's completion of ten years of Credited Service shall be computed by reducing the Participant's Accrued Frozen Benefit by using the Schedule A Actuarial Factors to reduce the Accrued Frozen Benefit to the Pension Starting Date.

B. Distribution with Respect to Married Participants . Notwithstanding Section 7.2(b) of the Plan, if a Participant will receive his or her Accrued Benefit in the form of a Qualified Joint and Survivor Annuity, the payments attributable to the Participant's Accrued Frozen Benefit shall be calculated and paid as follows:

1. Pension Starting Date After Attainment of Age 50 . Annuity payments will be made during the Participant's lifetime in an amount equal to the annual Accrued Frozen Benefit the Participant would have received if the Participant's Accrued Frozen Benefit were payable in the form of a single

life annuity for the Participant's lifetime reduced by the product of (i) 50% of the annual amount of Accrued Frozen Benefit the Participant would have received if the Participant's Accrued Frozen Benefit were payable in the form of a single life annuity for the Participant's lifetime multiplied by (ii) 40% of the applicable factor set forth in Table D.

Thereafter, if the Participant's Spouse shall survive the Participant, such Spouse shall receive during the remainder of the Spouse's lifetime an annual amount, payable monthly, equal to 50% of the annual amount the Participant would have received if the Participant's Accrued Frozen Benefit were payable as a single life annuity for the Participant's lifetime.

If the Participant survives the Spouse, such Participant shall receive during the remainder of the Participant's lifetime an annual amount payable monthly equal to the annual amount the Participant would have received if the Participant's Frozen Benefit were payable as a single life annuity for the Participant's lifetime.

2. Pension Starting Date Prior to Attainment of Age 50 . Annuity payments will be made during the Participant's lifetime in an amount equal to the annual Accrued Frozen Benefit the Participant would have received if the Participant's Accrued Frozen Benefit were payable in the form of a single life annuity for the Participant's lifetime multiplied by (i) an applicable factor determined by using the Schedule A Actuarial Factors.

Thereafter, if the Participant's Spouse shall survive the Participant, such Spouse shall receive during the remainder of the Spouse's lifetime an annual amount, payable monthly, equal to 50% of the annuity payment prior to the Participant's death.

If the Participant survives the Spouse, the monthly annuity will continue to be paid without any further adjustments during the remainder of the Participant's lifetime.

C. Post Retirement Adjustments . If a Participant's Pension Starting Date occurs on or after his or her 50^{th} birthday and the Participant's Accrued Frozen Benefit is paid in a form other than a lump sum distribution, the annual Accrued Frozen Benefit payable pursuant to this Schedule shall, subject to the limitations set forth in this paragraph C., be adjusted each October 1 for the twelve-month period then beginning by adding a post-retirement cost of living adjustment computed by applying an adjustment percentage to the appropriate base specified in this paragraph C. A Participant whose Pension Starting Date occurs prior to his or her 50^{th} birthday or who receives his or her Accrued Frozen Benefit in the form of a lump sum distribution shall not be entitled to any post-retirement cost of living adjustment under this Schedule. In addition, the post-retirement cost of living adjustment shall apply only to the portion of a Participant's Accrued Benefit that is attributable to his or her Accrued Frozen Benefit.

1. The adjustment percentage shall equal, for each October 1, the percentage by which the Consumer Price Index for the July immediately preceding such October 1 exceeds the Consumer Price Index for the July immediately preceding the twelve-month period beginning October 1 in which the Participant terminated employment or payment of a Pension commenced; provided, however, that:

   (a) If, as of such October 1, there shall be no such excess, the adjustment percentage shall be deemed to be zero for the twelve-month period beginning on such October 1.

   (b) There shall be no negative adjustment percentage.

   (c) The aggregate adjustment percentage for any twelve-month period beginning October 1 shall never be lower than the aggregate adjustment percentage for the preceding such period.

   (d) If the percentage increase in the Consumer Price Index computed for the twelve-month period beginning on October 1 does not exceed the aggregate adjustment percentage for the preceding twelve-month period by at least three percentage points, the aggregate adjustment percentage for the preceding twelve-month period shall continue in effect during such twelve-month period beginning on October 1.

   (e) The aggregate adjustment percentage for any twelve-month period beginning on October 1 shall not be more than seven percentage points greater than that for the preceding twelve-month period. If the aggregate adjustment percentage for any twelve-month period beginning on October 1 exceeds by more than seven percentage points the aggregate adjustment percentage for the preceding twelve-month period, the excess shall be carried over to succeeding twelve-month periods until such excess is reduced to zero.

   (f) The adjustment percentage for the twelve-month period beginning with the October 1 next following the date the Participant's Pension Starting Date shall be the adjustment percentage determined in accordance with the preceding provisions of this paragraph C. multiplied by a fraction the numerator of which shall be the number of full calendar months between such date and such October 1 and the denominator of which shall be twelve.

2. To determine the amount of the monthly cost of living adjustment, the adjustment percentage shall be applied to the first $500 per month of a Participant's Accrued Frozen Benefit, subject to a maximum monthly adjustment of $500 or, if the monthly amount of such Accrued Frozen Benefit is less than $500 per month, subject to a maximum monthly adjustment equal to the monthly Accrued Frozen Benefit payment. To

determine the amount of the adjustment made in the case of a Qualified Joint and Survivor Annuity or surviving Spouse annuity payable pursuant to Section 7.3 of the Plan to the surviving Spouse of a deceased Participant, a family pension payable pursuant to Section 4.B. of this Schedule to a surviving Dependent Minor Child or Children of a deceased Participant or a surviving dependent's pension payable pursuant to Section 4.C. of this Schedule to a surviving Dependent Disabled Child or Children of a deceased Participant, the adjustment percentage shall be applied to the first $250 per month of such annuity or pension, subject to a maximum monthly adjustment of $175 ($250 in the case of a Qualified Joint and Survivor Annuity) or, if the monthly amount of such annuity or pension is less than $175 ($250 in the case of a Qualified Joint and Survivor Annuity), subject to a maximum monthly adjustment equal to the monthly Accrued Frozen Benefit payment.

D. Lump Sum Value. If a Participant elects to receive his or her Accrued Frozen Benefit in the form of a lump sum distribution as described in Option 2 of Section 7.2(c) of the Plan, the amount of the lump sum attributable to the Participant's Accrued Frozen Benefit shall be the greater of:

1. the lump sum actuarial equivalent of the Participant's Accrued Frozen Benefit determined using the Schedule A Actuarial Factors, and

2. an amount equal to the present value of the Participant's Accrued Frozen Benefit determined as of December 31, 2001 using a 6.5% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female), assuming the Accrued Frozen Benefit otherwise payable at the Schedule A Normal Retirement Age would commence at the later of the Participant's attained age at December 31, 2001 or age 60 and credited with 6.5% interest for each Plan Year subsequent to December 31, 2001 during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year.

With respect to a Participant's lump sum value determined under subparagraph 1. above, if the Participant's Pension Starting Date occurs on or after his or her 50^{th} birthday, the actuarial equivalent of the Participant's Accrued Frozen Benefit shall reflect the post retirement adjustments, if any, defined in Paragraph 3.C of this Schedule.

4. OPTIONAL FORMS OF BENEFIT PAYABLE UPON RETIREMENT

In lieu of the forms of benefit available under Section 7.2 of the Plan, a Participant may elect to have the portion of his or her Accrued Benefit attributable to his or her Accrued Frozen Benefit paid in the following forms, subject to Section 7.4 (relating to election and waiver procedures):

A. Optional Qualified Joint and Survivor Annuity : A Participant who is married on the Participant's Pension Starting Date may elect to receive a Qualified Joint and

Survivor Annuity described in Section 7.2(b) of the Plan (relating to manner of distribution with respect to married Participants) with the portion of the Pension payable to the Participant's Spouse that is attributable to the Participant's Accrued Frozen Benefit of a percentage less than 50 of the Pension the Participant would have received if the Participant's Pension attributable to his or her Accrued Frozen Benefit were payable in the form of a single-life annuity for the Participant's lifetime. A Qualified Joint and Survivor Annuity described in this paragraph shall be payable at the same time and in the same manner as described in Section 7.2(b) of the Plan (relating to manner of distribution with respect to married Participant) and shall be computed in the same manner as described in Section 3.B. of this Schedule (relating to special rules regarding computation of benefits), except that the lesser percentage of Pension designated by the Participant shall be used.

B. Family Pension: A Participant who is not married on the Participant's Pension Starting Date and who, as of such date, has a Dependent Minor Child or Dependent Minor Children may elect to receive his or her Accrued Frozen Benefit in the form of a family pension payable in monthly payments for the Participant's lifetime and, thereafter, payable in monthly payments in equal shares to each of the Participant's Dependent Minor Children who have not yet attained age 21. The annual amount of the family pension payable to the Participant shall be the annual Accrued Frozen Benefit the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime, reduced by the product of (1) the annual amount of the family pension designated by the Participant for the Participant's surviving Dependent Minor Child or Children which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Pension payable in the form of a single life annuity for the Participant's lifetime multiplied by (2) (i) if the Participant is at least age 50 on his or her Pension Starting Date, the applicable factor set forth in Table E or (ii) if the Participant is not at least age 50 on his or her Pension Starting Date, the applicable factor determined by using the Schedule A Actuarial Factors. The annual amount of the family pension payable after the Participant's death to the Participant's Dependent Minor Child or Children who have not yet attained age 21 shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Pension the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime.

C. Surviving Dependent's Pension: A Participant who is not married on the Participant's Pension Starting Date and who, as of such date, has a Dependent Disabled Child or Dependent Disabled Children may elect to receive his or her Accrued Frozen Benefit in the form of a surviving dependent's pension payable in monthly payments for the Participant's lifetime and, thereafter, payable in monthly payments in equal shares to each of the Participant's Dependent Disabled Children who remain disabled. The annual amount of the surviving dependent's pension payable to the Participant shall be the annual Accrued Frozen Benefit the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime, reduced by the product of (1) the annual amount of the surviving dependent's pension designated by the Participant for the Participant's Dependent Disabled Child or Children, which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Pension payable in the form of a single life annuity for the Participant's lifetime multiplied by (2) (i) if the Participant is at least age 50 on his or her Pension Starting Date, 50% of the applicable factor set forth in Table D, such factor to be determined based on the age of the other parent of such Child or Children, at the Participant's Pension Starting Date or the age such other parent would have attained had such other parent survived or if, in either case, the age of such other parent cannot be determined, the age of the Participant or (ii) if the Participant is not at least age 50 on his or her Pension Starting Date, the applicable factor determined by using the Schedule A Actuarial Factors. The annual amount of the surviving dependent's pension payable after the Participant's death to the Participant's Dependent Disabled Child or Children who remain disabled shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Pension the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime.

D. 75% Marital Annuity: A Participant who is married on the Participant's Annuity Starting Date may elect to receive a 75% marital annuity with a Service Annuity payable to the Participant's Spouse, if the Participant predeceases such Spouse, of a percentage equal to 75 of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime. A 75% marital annuity described in this Section 6.2 shall be payable at the same time and in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) and shall be the actuarial equivalent of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities), determined by using the annual interest rate specified under section 417(e) of the Code for the November preceding the calendar year in which such distribution is made or commences, and the mortality table prescribed for purposes of section 417(e)(3)(A)(ii)(I) of the Code.

Table B1
Early Retirement Service Factors
Applicable Monthly Payments to Age 65

For purposes of Schedule A, in the case of a Pension commencing after a Participant's Early Retirement Date but prior to his or her Schedule A Normal Retirement Age, the following factors shall be applied to determine the reductions applicable to the benefit accrued while a Participant is not a member of IBEW Local Union 15 and, for purposes of Schedule B, in the case of a Pension commencing after a Participant's Early Retirement Date but prior to his or her Schedule B Normal Retirement Age, the following factors shall be applied to determine the reductions applicable to the Participant's benefit accrued under the PECO Plan*:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7200	.7225	.7250	.7275	.7300	.7325	.7350	.7375	.7400	.7425	.7450	.7475
51	.7500	.7525	.7550	.7575	.7600	.7625	.7650	.7675	.7700	.7725	.7750	.7775
52	.7800	.7825	.7850	.7875	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075
53	.8100	.8125	.8150	.8175	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375
54	.8400	.8425	.8450	.8475	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675
55	.8700	.8725	.8750	.8775	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975
56	.9000	.9025	.9050	.9075	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275
57	.9300	.9325	.9350	.9375	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575
58	.9600	.9617	.9633	.9650	.9667	.9683	.9700	.9717	.9733	.9750	.9767	.9783
59*	.9800	.9817	.9833	.9850	.9867	.9883	.9900	.9917	.9933	.9950	.9967	.9983
60	1.0000											

*** Effective January 1, 2002, for Craft, Craft/Technical, Technical Support and Professional Support Employees with an accrued benefit under the PECO Plan, factor shall be 1.0000 at ages 59 and above**

For purposes of Schedule A, in the case of a Pension commencing after a Participant's Early Retirement Date but prior to his or her Schedule A Normal Retirement Age, the following factors shall be applied to determine the reductions applicable to the benefit accrued while the Participant is a member of IBEW Local Union 15:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075	.8100	.8125	.8150	.8175
51	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375	.8400	.8425	.8450	.8475
52	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675	.8700	.8725	.8750	.8775
53	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975	.9000	.9025	.9050	.9075
54	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275	.9300	.9325	.9350	.9375
55	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575	.9600	.9625	.9650	.9675
56	.9700	.9725	.9750	.9775	.9800	.9825	.9850	.9875	.9900	.9925	.9950	.9975
57	1.0000											

Table D
Qualified Joint and Survivor Annuity Factors

YOUNGER (-) OR OLDER (+) THAN EMPLOYEE AT RETIREMENT	AGE OF EMPLOYEE AT RETIREMENT															
	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65
-20	.1334	.1432	.1537	.1650	.1771	.1901	.2040	.2189	.2349	.2520	.2703	.2897	.3103	.3322	.3554	.3799
-19	.1324	.1420	.1524	.1636	.1756	.1884	.2022	.2169	.2326	.2495	.2675	.2866	.3070	.3285	.3514	.3754
-18	.1312	.1408	.1511	.1621	.1739	.1866	.2002	.2147	.2302	.2469	.2646	.2835	.3035	.3247	.3471	.3707
-17	.1301	.1395	.1496	.1605	.1722	.1847	.1981	.2124	.2277	.2441	.2616	.2801	.2998	.3206	.3427	.3658
-16	.1288	.1381	.1481	.1589	.1704	.1827	.1959	.2100	.2250	.2412	.2583	.2766	.2959	.3164	.3380	.3607
-15	.1275	.1367	.1465	.1571	.1685	.1806	.1936	.2074	.2222	.2381	.2550	.2729	.2918	.3119	.3331	.3553
-14	.1261	.1351	.1448	.1553	.1664	.1784	.1911	.2048	.2193	.2349	.2514	.2690	.2876	.3073	.3280	.3498
-13	.1246	.1335	.1431	.1533	.1643	.1761	.1886	.2020	.2162	.2315	.2478	.2650	.2832	.3024	.3227	.3440
-12	.1231	.1318	.1412	.1513	.1621	.1736	.1859	.1990	.2130	.2280	.2439	.2608	.2786	.2974	.3172	.3379
-11	.1214	.1301	.1393	.1492	.1598	.1711	.1831	.1960	.2097	.2244	.2399	.2564	.2738	.2921	.3115	.3317
-10	.1198	.1282	.1373	.1470	.1574	.1684	.1802	.1928	.2062	.2206	.2358	.2519	.2688	.2867	.3056	.3253
-9	.1180	.1263	.1352	.1447	.1548	.1657	.1772	.1895	.2026	.2166	.2315	.2472	.2637	.2812	.2995	.3187
-8	.1162	.1243	.1330	.1423	.1522	.1628	.1741	.1861	.1989	.2126	.2271	.2424	.2585	.2755	.2933	.3120
-7	.1143	.1222	.1307	.1398	.1495	.1599	.1709	.1826	.1951	.2084	.2225	.2374	.2531	.2696	.2869	.3051
-6	.1123	.1201	.1284	.1372	.1467	.1568	.1676	.1790	.1911	.2041	.2178	.2323	.2475	.2636	.2804	.2980
-5	.1103	.1178	.1259	.1346	.1438	.1537	.1641	.1752	.1871	.1997	.2130	.2271	.2419	.2575	.2738	.2909
-4	.1082	.1155	.1234	.1319	.1409	.1504	.1606	.1714	.1829	.1951	.2081	.2217	.2361	.2512	.2671	.2836
-3	.1060	.1132	.1209	.1291	.1378	.1471	.1570	.1675	.1786	.1905	.2031	.2163	.2302	.2449	.2602	.2762
-2	.1038	.1108	.1182	.1262	.1347	.1437	.1533	.1635	.1743	.1858	.1980	.2108	.2243	.2385	.2533	.2687
-1	.1015	.1083	.1155	.1233	.1315	.1403	.1496	.1594	.1699	.1811	.1928	.2053	.2183	.2320	.2463	.2612
0	.0992	.1057	.1128	.1203	.1283	.1367	.1457	.1553	.1654	.1762	.1876	.1996	.2122	.2254	.2393	.2536
+1	.0968	.1032	.1100	.1172	.1250	.1332	.1419	.1511	.1609	.1713	.1824	.1939	.2061	.2188	.2322	.2460
+2	.0944	.1005	.1071	.1142	.1216	.1296	.1380	.1469	.1563	.1664	.1771	.1882	.1999	.2122	.2250	.2383
+3	.0919	.0979	.1042	.1110	.1182	.1259	.1340	.1426	.1517	.1615	.1717	.1825	.1938	.2056	.2179	.2307
+4	.0894	.0952	.1013	.1079	.1148	.1222	.1300	.1383	.1471	.1565	.1664	.1767	.1876	.1989	.2107	.2230
+5	.0869	.0925	.0984	.1047	.1114	.1185	.1261	.1340	.1425	.1515	.1610	.1709	.1813	.1922	.2036	.2153
+6	.0844	.0897	.0954	.1015	.1080	.1148	.1221	.1297	.1379	.1465	.1556	.1652	.1751	.1856	.1964	.2077
+7	.0819	.0870	.0925	.0983	.1045	.1111	.1181	.1254	.1332	.1415	.1503	.1594	.1690	.1789	.1893	.2000
+8	.0793	.0843	.0895	.0951	.1011	.1074	.1141	.1211	.1286	.1366	.1449	.1537	.1628	.1724	.1823	.1924
+9	.0768	.0815	.0866	.0920	.0977	.1037	.1101	.1169	.1240	.1316	.1396	.1480	.1567	.1658	.1752	.1848
+10	.0742	.0788	.0836	.0888	0943	.1001	.1062	.1126	.1195	.1267	.1344	.1423	.1506	.1593	.1682	.1773
+11	.0717	.0761	.0807	.0856	.0909	.0964	.1022	.1084	.1149	.1219	.1292	.1367	.1446	.1528	.1612	.1698
+12	.0692	.0734	.0778	.0825	.0875	.0928	.0984	.1042	.1105	.1171	.1240	.1312	.1386	.1463	.1543	.1624
+13	.0667	.0707	.0749	.0794	.0842	.0892	.0945	.1001	.1060	.1123	.1189	.1257	.1327	.1400	.1474	.1550
+14	.0643	.0680	.0721	.0764	.0809	.0857	.0907	.0960	.1016	.1076	.1138	.1202	.1268	.1337	.1407	.1479
+15	.0618	.0654	.0693	.0733	.0776	.0822	.0870	.0920	.0973	.1029	.1088	.1148	.1210	.1274	.1341	.1408
+16	.0594	.0629	.0665	.0704	.0744	.0788	.0833	.0881	.0931	.0983	.1038	.1095	.1153	.1214	.1276	.1340
+17	.0571	.0603	.0638	.0674	.0713	.0754	.0797	.0841	.0888	.0938	.0990	.1043	.1098	.1155	.1214	.1275
+18	.0547	.0578	.0611	.0646	.0682	.0721	.0761	.0803	.0847	.0894	.0942	.0992	.1044	.1098	.1154	.1212
+19	.0525	.0554	.0585	.0618	.0652	.0688	.0726	.0765	.0806	.0850	.0895	.0943	.0991	.1042	.1096	.1151
+20	.0502	.0530	.0559	.0590	.0622	.0656	.0691	.0728	.0767	.0808	.0850	.0895	.0941	.0989	.1040	.1093

FACTORS FOR AGE COMBINATIONS NOT SHOWN ARE COMPUTED ON THE SAME ACTUARIAL BASIS AS THAT USED FOR COMPUTATION OF THE FACTORS STATED IN THE ABOVE TABLE. AS PROVIDED IN SECTION 3.B. OF SCHEDULE A, 40% OF THE APPROPRIATE FACTOR PROVIDED FOR BY THIS TABLE IS TO BE USED IN DETERMINING THE AMOUNT OF THE QUALIFIED JOINT AND SURVIVOR ANNUITY ATTRIBUTABLE TO A PARTICIPANT'S ACCRUED FROZEN BENEFIT.

Table E
Family Annuity Factors

AGE OF YOUNGEST CHILD	AGE OF EMPLOYEE AT RETIREMENT															
	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65
20	.0012	.0014	.0016	.0018	.0020	.0023	.0027	.0030	.0034	.0038	.0043	.0049	.0055	.0063	.0071	.0080
19	.0033	.0037	.0041	.0046	.0052	.0058	.0065	.0072	.0081	.0090	.0102	.0114	.0128	.0143	.0161	.0181
18	.0055	.0061	.0068	.0076	.0084	.0094	.0104	.0116	.0129	.0145	.0162	.0181	.0203	.0227	.0255	.0287
17	.0078	.0086	.0096	.0106	.0118	.0131	.0146	.0162	.0180	.0201	.0225	.0252	.0282	.0315	.0354	.0398
16	.0101	.0112	.0124	.0138	.0153	.0170	.0188	.0209	.0233	.0260	.0291	.0325	.0364	.0408	.0458	.0514
15	.0126	.0139	.0153	.0170	.0189	.0209	.0233	.0259	.0288	.0322	.0360	.0402	.0450	.0504	.0565	.0634
14	.0151	.0166	.0184	.0204	.0226	.0251	.0279	.0310	.0345	.0386	.0431	.0482	.0540	.0604	.0677	.0758
13	.0176	.0195	.0215	.0238	.0264	.0294	.0326	.0363	.0405	.0452	.0505	.0565	.0632	.0708	.0792	.0886
12	.0203	.0224	.0247	.0274	.0304	.0338	.0376	.0418	.0466	.0521	.0582	.0651	.0728	.0815	.0911	.1016
11	.0230	.0254	.0281	`.0311	.0346	.0384	.0427	.0475	.0530	.0592	.0662	.0740	.0827	.0924	.1032	.1149
10	.0258	.0285	.0315	.0350	.0388	.0431	.0480	.0534	.0596	.0666	.0744	.0832	.0929	.1036	.1154	.1284
9	.0287	.0317	.0351	.0389	.0432	.0480	.0534	.0595	.0664	.0742	.0828	.0925	.1032	.1149	.1279	.1419
8	.0316	.0350	.0387	.0430	.0477	.0531	.0591	.0658	.0734	.0819	.0915	.1020	.1136	.1264	.1404	.1556
7	.0347	.0383	.0425	.0471	.0524	.0583	.0649	.0722	.0805	.0899	.1002	.1116	.1241	.1379	.1530	.1694
6	.0378	.0418	.0463	.0514	.0572	.0636	.0708	.0788	.0878	.0979	.1090	.1213	.1347	.1495	.1656	.1831
5	.0410	.0454	.0503	.0559	.0621	.0691	.0768	.0855	.0952	.1060	.1179	.1310	.1453	.1611	.1782	.1969
4	.0443	.0490	.0544	.0604	.0671	.0746	.0830	.0923	.1027	.1142	.1268	.1407	.1559	.1726	.1908	.2105
3	.0476	.0528	.0585	.0650	.0722	.0803	.0892	.0991	.1101	.1223	.1357	.1504	.1669	.1841	.2032	.2240
2	.0511	.0566	.0628	.0697	.0774	.0860	.0955	.1060	.1176	.1305	.1446	.1601	.1770	.1954	.2155	.2372
1	.0546	.0605	.0671	.0745	.0826	.0917	.1018	.1128	.1251	.1386	.1534	.1696	.1873	.2066	.2275	.2501

FACTORS FOR AGE COMPUTATIONS NOT SHOWN ARE COMPUTED ON THE SAME ACTUARIAL BASIS AS THAT USED FOR COMPUTATION OF THE FACTORS STATED IN THE ABOVE TABLE. AS PROVIDED IN SECTION 4.B. OF SCHEDULE A, 100% OF THE APPROPRIATE FACTOR PROVIDED FOR BY THIS TABLE IS TO BE USED IN DETERMINING THE AMOUNT OF THE FAMILY ANNUITY ATTRIBUTABLE TO A PARTICIPANT'S ACCRUED FROZEN BENEFIT.

Table F
Deferred Vesting Schedule

AGE AT TERMINATION	AGE THAT VESTED BENEFITS BEGIN 50	51	52	53	54	55	56	57	58	59	60
49	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	88.0%	91.0%	94.0%	97.0%	100%
48	69.0%	72.1%	75.2%	78.3%	81.4%	84.5%	87.6%	90.7%	93.8%	96.9%	100%
47	68.0%	71.2%	74.4%	77.6%	80.8%	84.0%	87.2%	90.4%	93.6%	96.8%	100%
46	67.0%	70.3%	73.6%	76.9%	80.2%	83.5%	86.8%	90.1%	93.4%	96.7%	100%
45	66.0%	69.4%	72.8%	76.2%	79.6%	83.0%	86.4%	89.8%	93.2%	96.6%	100%
44	65.0%	68.5%	72.0%	75.5%	79.0%	82.5%	86.0%	89.5%	93.0%	96.5%	100%
43	64.0%	67.6%	71.2%	74.8%	78.4%	82.0%	85.6%	89.2%	92.8%	96.4%	100%
42	63.0%	66.7%	70.4%	74.1%	77.8%	81.5%	85.2%	88.9%	92.6%	96.3%	100%
41	62.0%	65.8%	69.6%	73.4%	77.2%	81.0%	84.8%	88.6%	92.4%	96.2%	100%
40	61.0%	64.9%	68.8%	72.7%	76.6%	80.5%	84.4%	88.3%	92.2%	96.1%	100%
39	60.0%	64.0%	68.0%	72.0%	76.0%	80.0%	84.0%	88.0%	92.0%	96.0%	100%
38	59.0%	63.1%	67.2%	71.3%	75.4%	79.5%	83.6%	87.7%	91.8%	95.9%	100%
37	58.0%	62.2%	66.4%	70.6%	74.8%	79.0%	83.2%	87.4%	91.6%	95.8%	100%
36	57.0%	61.3%	65.6%	69.9%	74.2%	78.5%	82.8%	87.1%	91.4%	95.7%	100%
35	56.0%	60.4%	64.8%	69.2%	73.6%	78.0%	82.4%	86.8%	91.2%	95.6%	100%
34	55.0%	59.5%	64.0%	68.5%	73.0%	77.5%	82.0%	86.5%	91.0%	95.5%	100%
33	54.0%	58.6%	63.2%	67.8%	72.4%	77.0%	81.6%	86.2%	90.8%	95.4%	100%
32	53.0%	57.7%	62.4%	67.1%	71.8%	76.5%	81.2%	85.9%	90.6%	95.3%	100%
31	52.0%	56.8%	61.6%	66.4%	71.2%	76.0%	80.8%	85.6%	90.4%	95.2%	100%
30	51.0%	55.9%	60.8%	65.7%	70.6%	75.5%	80.4%	85.3%	90.2%	95.1%	100%
29	50.0%	55.0%	60.0%	65.0%	70.0%	75.0%	80.0%	85.0%	90.0%	95.0%	100%
28	49.0%	54.1%	59.2%	64.3%	69.4%	74.5%	79.6%	84.7%	89.8%	94.9%	100%
27	48.0%	53.2%	58.4%	63.6%	68.8%	74.0%	79.2%	84.4%	89.6%	94.8%	100%
26	47.0%	52.3%	57.6%	62.9%	68.2%	73.5%	78.8%	84.1%	89.4%	94.7%	100%
25	46.0%	51.4%	56.8%	62.2%	67.6%	73.0%	78.4%	83.8%	89.2%	94.6%	100%
24	45.0%	50.5%	56.0%	61.5%	67.0%	72.5%	78.0%	83.5%	89.0%	94.5%	100%
23	44.0%	49.6%	55.2%	60.8%	66.4%	72.0%	77.6%	83.2%	88.8%	94.4%	100%
22	43.0%	48.7%	54.4%	60.1%	65.8%	71.5%	77.2%	82.9%	88.6%	94.3%	100%
21	42.0%	47.8%	53.6%	59.4%	65.2%	71.0%	76.8%	82.6%	88.4%	94.2%	100%
20	41.0%	46.9%	52.8%	58.7%	64.6%	70.5%	76.4%	82.3%	88.2%	94.1%	100%

NOTE: EMPLOYEES MUST HAVE 5 YEARS OF SERVICE TO QUALIFY FOR VESTING

SCHEDULE INDICATES PERCENTAGE OF VESTED BENEFIT PAYABLE
INTERPOLATION WILL BE MADE TO THE NEAREST MONTH

SCHEDULE B

**PROVISIONS APPLICABLE TO
ACCRUED FROZEN BENEFIT
UNDER THE SERVICE ANNUITY PLAN
OF PECO ENERGY COMPANY**

1. APPLICATION

This Schedule shall apply only to a Participant who elects to participate in the Plan pursuant to Section 3.1(b) of the Plan (relating to eligibility for participation for employees other than new hires) or Section 9.1 of the Plan (relating to recommencement of employment by terminated employee) and whose accrued benefit under the PECO Plan is transferred to the Plan pursuant to Section 3.1(c) of the Plan (relating to transfer of benefits and assets to Plan) or Section 9.1 of the Plan. The provisions of this Schedule shall govern with respect to all matters relating to such a Participant's Accrued Frozen Benefit.

2. DEFINED TERMS

For purposes of this Schedule B, capitalized terms used herein shall have their respective meanings set forth in the Plan, except that the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Accrued Frozen Benefit. The amount payable with respect to a Participant's accrued benefit under the PECO Plan determined as of December 31, 2001 commencing on the first day of the month coinciding with or next following a Participant's Schedule B Normal Retirement Age, determined as if such amount were payable in the form of a single life annuity for the life of the Participant.

B. Benefit Years. For periods prior to January 1, 2002, a Participant's Benefit Years includes the Participant's "benefit years" as of the date he or she becomes a Participant, determined in accordance with the provisions of the PECO Plan as in effect on December 31, 2001. For the Participant's 12 month "benefit accrual computation period" (as defined in the PECO Plan) that ends during the 2002 Plan Year, the greater of (i) the Vesting Service, for such period, determined pursuant to subdivision (47) of Article 2 of the Plan (relating to definition of Vesting Service) and (ii) the "benefit years", for such period, determined pursuant to the terms of the PECO Plan as in effect on December 31, 2001. For periods after the 12 month period described in the preceding sentence, a Participant's Benefit Years shall equal his or her Vesting Service for such periods.

C. Early Retirement Date. The date on which a Participant completes at least ten years of Vesting Service and attains at least age 50.

D. Schedule B Actuarial Factors. An interest rate assumption of seven percent and a mortality assumption of the TPF&C mortality table in effect as of the date a determination hereunder occurs set back one year for participants and five years for beneficiaries.

E. Schedule B Normal Retirement Age. A Participant's 65th birthday.

3. SPECIAL RULES REGARDING COMPUTATION OF BENEFIT

A. Factors to Calculate Pension Paid Before Schedule B Normal Retirement Age

1. Pension Starting Date on or After Early Retirement Date and Prior to Schedule B Normal Retirement Age. The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Early Retirement Date and whose Pension commences prior to his or her Schedule B Normal Retirement Age shall be computed by multiplying such Participant's Accrued Frozen Benefit by the applicable factor from Table B-1.

2. Pension Starting Date After Attainment of Age 50 but Prior to Early Retirement Date. The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs on or after such Participant's attainment of age 50 but prior to such Participant's attainment of his or her Early Retirement Date and whose Pension commences prior to his or her Schedule B Normal Retirement Age shall be computed by multiplying such Participant's Accrued Frozen Benefit by the applicable factor from Table G.

3. Pension Starting Date Prior to Attainment of Age 50. The amount determined by actuarially reducing the Participant's Accrued Frozen Benefit using the factors in Table G to reduce the Accrued Frozen Benefit from age 65 to age 50 and using the Schedule B Actuarial Factors to reduce the Accrued Frozen Benefit from age 50 to the Participant's Pension Starting Date.

B. Lump Sum Value. If a Participant elects to receive his or her Accrued Frozen Benefit in the form of a lump sum distribution as described in Option 2 of Section 7.2(c) of the Plan, the amount of the lump sum attributable to the Participant's Accrued Frozen Benefit shall be the greater of:

1. the actuarial equivalent of the Participant's Accrued Frozen Benefit using the Schedule B Actuarial Factors, and
2. an amount equal to the present value of the Participant's Accrued Frozen Benefit determined as of December 31, 2001 using a 6.5% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female), assuming the Accrued Frozen Benefit otherwise payable at the Schedule B Normal Retirement Age would commence at the later of the Participant's attained age at December 31, 2001 or age 60 (or, effective January 1, 2002, age 59 for Craft, Craft/Technical, Technical Support and Professional Support Employees with an Accrued Frozen Benefit) and credited with 6.5% for each Plan Year subsequent to December 31, 2001 during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year.

4. OPTIONAL FORMS OF BENEFIT PAYABLE UPON RETIREMENT

In lieu of the optional forms of benefit available under Section 7.2(c) of the Plan, a Participant may elect to have the portion of his or her Accrued Benefit attributable to his or her Accrued Frozen Benefit paid in the following form, subject to Section 7.4 (relating to election and waiver procedures):

A. Contingent Annuity Option: A Participant (each, an "Eligible Participant") who has a Termination of Employment after he or she (1) has completed at least 14 Benefit Years, or (2) has attained age 65 and has completed at least 5 Benefit Years, or (3) has attained his or her Early Retirement Date may elect a contingent annuity option under which the Participant may designate a percentage equal to 25%, 50%, 75% or 100% of his or her Pension to be paid upon his or her death to a contingent Beneficiary designated by such Participant. The annuity otherwise payable to a Participant electing a Contingent Annuity Option or to his or her contingent Beneficiary will be actuarially reduced using the Schedule B Actuarial Factors to reflect the payments which may become payable to the Beneficiary. Notwithstanding the preceding sentence, if the Participant's Spouse is designated as the contingent Beneficiary, the actuarial reduction will not reflect the cost of a joint and survivor annuity option providing a survivor annuity to the Participant's Spouse of

(1) 50% of the amount payable to the Participant, if a 50%, 75% or 100% contingent annuity option is elected, or (2) 25% of the amount payable to the Participant, if a 25% contingent annuity option is elected; provided, however, that the subsidy described in this sentence shall not apply to a former spouse who is to be treated as a Participant's spouse pursuant to a qualified domestic relations order, unless the qualified domestic relations order specifically provides that such subsidy applies to the former spouse. If the contingent Beneficiary is other than the Spouse, the percentage payable to the contingent Beneficiary after the Participant's death may not exceed the applicable percentage from Appendix B. The contingent annuity option of an electing Participant who has a Termination of Employment before he or she attains his or her Early Retirement Date shall be canceled.

APPENDIX B

MINIMUM DISTRIBUTION INCIDENTAL BENEFIT TABLE

Excess if Age of Participant over Age of Beneficiary	Applicable Percentage
10 years or less	100%
11	96%
12	93%
13	90%
14	87%
15	84%
16	82%
17	79%
18	77%
19	75%
20	73%
21	72%
22	70%
23	68%
24	67%
25	66%
26	64%
27	63%
28	62%
29	61%
30	60%
31	59%
32	59%
33	58%
34	57%
35	56%
36	56%
37	55%
38	55%
39	54%
40	54%
41	53%
42	53%
43	53%
44 and greater	52%

Table G

Reduction Factors Applicable to Accrued Frozen Benefit under Schedule B
For Pension Starting Date on or after Age 50 and before Early Retirement Age*

Months

Age	0	1	2	3	4	5	6	7	8	9	10	11
50	0.235	0.237	0.239	0.240	0.242	0.244	0.246	0.247	0.249	0.251	0.253	0.254
51	0.256	0.258	0.260	0.262	0.264	0.266	0.268	0.269	0.271	0.273	0.275	0.277
52	0.279	0.281	0.283	0.286	0.288	0.290	0.292	0.294	0.296	0.299	0.301	0.303
53	0.305	0.307	0.310	0.312	0.314	0.317	0.319	0.321	0.324	0.326	0.328	0.331
54	0.333	0.336	0.338	0.341	0.344	0.346	0.349	0.352	0.354	0.357	0.360	0.362
55	0.365	0.368	0.371	0.374	0.377	0.380	0.383	0.385	0.388	0.391	0.394	0.397
56	0.400	0.403	0.407	0.410	0.413	0.417	0.420	0.423	0.427	0.430	0.433	0.437
57	0.440	0.444	0.447	0.451	0.455	0.458	0.462	0.466	0.469	0.473	0.477	0.480
58	0.484	0.488	0.492	0.496	0.500	0.504	0.509	0.513	0.517	0.521	0.525	0.529
59	0.533	0.538	0.542	0.547	0.552	0.556	0.561	0.566	0.570	0.575	0.580	0.584
60	0.589	0.594	0.599	0.605	0.610	0.615	0.620	0.625	0.630	0.636	0.641	0.646
61	0.651	0.657	0.663	0.669	0.675	0.681	0.687	0.692	0.698	0.704	0.710	0.716
62	0.722	0.729	0.736	0.742	0.749	0.756	0.763	0.769	0.776	0.783	0.790	0.796
63	0.803	0.811	0.818	0.826	0.834	0.841	0.849	0.857	0.864	0.872	0.880	0.887
64	0.895	0.904	0.913	0.921	0.930	0.939	0.948	0.956	0.965	0.974	0.983	0.991
65 and Over	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

* Factors above are to be multiplied by the Frozen Accrued Benefit applicable to Schedule B. The Basis for the above Factors is the 1971 TPF&C Projection Mortality Table for Males with 1-Year Setback, and 7.00% Interest.

SCHEDULE C
PROVISIONS APPLICABLE TO
ACCRUED FROZEN BENEFIT
UNDER THE CASH BALANCE PROVISIONS
OF THE TXU RETIREMENT PLAN

1. APPLICATION

This Schedule C shall apply only to a Participant who, immediately prior to becoming a Participant, was a participant in the TXU Retirement Plan (the "TXU Plan"). The provisions of this Schedule C shall govern with respect to all matters relating to such a Participant's Cash Balance Account that is attributable to the Participant's accrued benefit under the TXU Plan.

2. DEFINED TERMS

For purposes of this Schedule C, capitalized terms used herein shall have their respective meanings set forth in the Plan, except that the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Accrued Frozen Benefit. The amount payable with respect to a Participant's accrued benefit under the TXU Plan determined as of the date such Participant became a Participant commencing on the first day of the month coinciding with or next following a Participant's Schedule C Normal Retirement Age, determined as if such amount were payable in the form of a single life annuity for the life of the Participant.

B. Accredited Service. A Participant's Accredited Service includes the Participant's "Accredited Service" as of the date he or she becomes a Participant, determined in accordance with the provisions of the TXU Plan as in effect on such date, and the number of years and full calendar months of service beginning on the date the Participant becomes a Participant and ending on the Participant's Severance from Service Date (as defined below) but not to exceed, in the aggregate, a maximum of 40 years. A Participant's Severance from Service is the earlier of the first day of the month coincident with or next following the date on which an Employee quits, retires or is discharged or dies, or the first day of the month coincident with or next following the first anniversary of the first day of absence for any other reason. Severance from Service shall not occur if an Employee leaves the employ of an Employer and is eligible for disability benefits as defined in and determined under the TXU Corp. Employee Long-Term Disability Income Plan (or any successor plan), so long as such Employee remains eligible for disability benefits. Accredited Service shall not include any Period of Service for which the Accrued Frozen Benefit has been settled by a cash payment, unless, within the latter of: (a) 5 years of reemployment, or (b) 5 consecutive one-year breaks in service, the full cash payment is repaid together with interest at the annual compound rate of interest as may be specified by law from the date of the cash payment to the date of repayment.

C. Earlier Than Normal Retirement Date. The date on which a Participant attains age 55 and completes at least 15 years of Accredited Service.

D. Schedule C Actuarial Factors. With respect to the computation of lump sum benefit payments, the mortality table prescribed in Revenue Ruling 2001-62 and an interest rate equal to the annual rate on 30-year U.S. Treasury securities for the month of November prior to the Plan Year for which the lump sum payment is being determined. With respect to the computation of monthly benefit payments, a unisex rate taken from the 1983 Group Annuity Mortality Table weighted to reflect a fixed blend of 85% males and 15% females and interest rate equal to 8%.

E. Schedule C Normal Retirement Age. Age 65.

3. SPECIAL RULES REGARDING COMPUTATION OF BENEFIT

A. Factors to Calculate Pension Paid Before Schedule C Normal Retirement Age

1. Pension Starting Date on or After the Earlier Than Normal Retirement Date and Attainment of Age 62, but Prior to Schedule C Normal Retirement Age. The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Earlier Than Normal Retirement Date and whose Pension commences after his or her attainment of age 62, but prior to his or her Schedule C Normal Retirement Age shall be such Participant's Accrued Frozen Benefit without any actuarial reduction.

2. Pension Starting Date on or After the Earlier Than Normal Retirement Date and Prior to Attainment of Age 62. The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Earlier Than Normal Retirement Date and whose Pension commences before his or her attainment of age 62 shall be such Participant's Accrued Frozen Benefit reduced at the annual rate of 4% for each of the years and full calendar months (taken as twelfths of a year) by which his Earlier Than Normal Retirement Date precedes the first day of the month coincident with or next following his 62nd birthday.

3. Pension Starting Date Prior to the Earlier Than Normal Retirement Date. The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs prior to his or her Earlier than Normal Retirement Date shall be the Participant's Accrued Frozen Benefit reduced at the annual rate of 4% for each of the years and full calendar months (taken as twelfths of a year) to the greater of his age as of his Pension Starting Date or age 55 and further reduced (if applicable) on an actuarial basis from age 55 to the Participant's Pension Starting Date.

B. Lump Sum Value. If a Participant elects to receive his or her Accrued Frozen Benefit in the form of a lump sum distribution as described in Option 2 of Section 7.2(c) of the Plan, the amount of the lump sum attributable to the Participant's Accrued Frozen Benefit shall be the greater of:

1. the lump sum actuarial equivalent of the Participant's Accrued Frozen Benefit determined using the Schedule C Actuarial Factors, and

2. an amount equal to the present value of the Participant's Accrued Frozen Benefit determined as the date the Participant became a Participant in the Plan using a 6.75% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female). assuming the Accrued Frozen Benefit otherwise payable at the Schedule C Normal Retirement Age would commence at the later of the Participant's attained age as of the date the Participant became a Participant in the Plan or age 62.

4. OPTIONAL FORMS OF BENEFIT PAYABLE UPON RETIREMENT

In lieu of the forms of benefit available under Section 7.2 of the Plan, a Participant may elect to have the portion of his or her Accrued Benefit attributable to his or her Accrued Frozen Benefit paid in the following forms, subject to Section 7.4 (relating to election and waiver procedures):

A. Ten- Year Certain Option: A Participant may elect to receive his or her Accrued Frozen Benefit in the form of a reduced amount which is the Actuarial Equivalent, determined using the Schedule C Actuarial Assumptions, of his or her Accrued Frozen Benefit during his or her lifetime and, in the event of the Participant's death prior to the expiration of ten years following his or her Pension Starting Date, such Accrued Frozen Benefit shall continue for any unexpired portion of such ten-year period to his designated Beneficiary or Beneficiaries. Subject to Section 7.4, the Participant shall have the right to change or redesignate his or her Beneficiary or successive Beneficiaries at any time prior to the expiration of the ten-year period described above. If the Beneficiary or successive Beneficiaries shall survive the retired Participant but die prior to the expiration of the ten-year period described above, the commuted value of the remaining payments due the Beneficiaries shall be paid to the estate of such Beneficiaries. If the Participant shall die within the ten-year period described above without any surviving designated Beneficiary, the commuted value of the payments which would otherwise have been paid during the remaining portion of said ten-year period shall be paid by the Trustee at the direction of the Administrator (i) to the surviving Spouse of such deceased Participant, if any, or (ii) if there shall be no surviving Spouse, to the surviving children of such deceased Participant, if any, in equal shares, or (iii) if there shall be no surviving Spouse or surviving children, to the executor or administrator of the estate of such deceased Participant, or (iv) if no executor or administrator shall have been appointed for the estate of such deceased Participant within six months following the date of the Participant's death, in equal shares to the person or persons who would be entitled under the intestate succession laws of the state of the Participant's domicile to receive the Participant's personal estate.

B. Social Security Adjustment Option: A Participant whose Pension Starting Date occurs after his or her Earlier Than Normal Retirement Date and prior to his or her attainment of age 62 may elect, at any time prior to his or Earlier Than Normal Retirement Date, to have the amount of his or her Accrued Frozen Benefit increased during the period prior to becoming eligible to receive monthly benefits under the Social Security Act, and decreased during the period after becoming eligible to receive monthly benefits under the Social Security Act, so as to provide for the Participant an essentially uniform total retirement benefit composed of his Accrued Frozen Benefit and monthly benefits under the Social Security Act. For purposes of this optional form of benefit, the monthly benefits under the Social Security Act shall mean the old age insurance benefit that a Participant might be entitled to receive at the earliest age the Participant will be eligible to begin receiving monthly benefit under the Social Security Act as of the date he or she elects this optional form of benefit and the Accrued Frozen Benefit shall not be adjusted because of any subsequent change in the actual monthly benefits received under the Social Security Act. If the Participant elects the Social Security Adjustment Option, his or her Accrued Frozen Benefit shall be the greater of (i) the Accrued Frozen Benefit reduced as described in Paragraph 3.A.2 of this Schedule C and applying the Schedule C Actuarial Assumptions for computing monthly benefit payments; and (ii) the Accrued Frozen Benefit actuarially reduced to the Participant's age at retirement and converted to the Social Security Adjustment Option applying the Schedule C Actuarial Assumptions for calculating lump sum benefit payments.

Exhibit 10.21

EXELON CORPORATION
SENIOR MANAGEMENT
SEVERANCE PLAN
(As Amended and Restated)

EXELON CORPORATION
SENIOR MANAGEMENT SEVERANCE PLAN
(As Amended and Restated)

1. PURPOSE OF THE PLAN

The Exelon Corporation Senior Management Severance Plan, as amended and restated herein (the " Plan"), is effective as of April 1, 2013 (the "Effective Date") except as otherwise specifically provided herein, and supersedes in its entirety all prior versions of the Plan with respect to terminations of employment occurring any time on or after the Effective Date (or such other date as set forth herein). The Plan provides severance benefits to eligible executives of Exelon Corporation ("Exelon") and its subsidiaries of which Exelon owns at least 80% of the outstanding voting power that are designated by the Plan Administrator as participating employers in the Plan (Exelon and such subsidiaries jointly and severally referred to as the " Company") who submit a Notice of Termination or who are notified of their termination of employment on or after the Effective Date (or such other date as set forth herein), and to provide additional protection in the event of a Change in Control of Exelon or an Imminent Control Change of Exelon.

2. ELIGIBILITY

2.1. Eligibility in General. Subject to the remaining provisions of this Section 2.1, eligibility to participate in the Plan is limited to each employee of the Company whose position is in Salary Band E09 (or equivalent executive grade) or above (an " Executive") who executes and returns to the Company by the later of 90 days after becoming an Executive, or 90 days after delivery thereof to the Executive, non-competition, non-solicitation, confidential information and intellectual property covenants (" Restrictive Covenants") which are acceptable to Exelon and are either substantially in the form attached hereto and made a part hereof as Exhibit I (as may be modified from time to time by Exelon in its sole discretion) or set forth in another agreement between the Company and the Executive. Notwithstanding any provision of the Plan to the contrary, eligibility for benefits under the Plan shall be subject to the provisions of any agreement (including but not limited to an offer of employment or grant instrument) between an Executive and the Company providing that that such Executive would be ineligible for (or waives) all or a portion of the benefits under the Plan or "change in control" benefits in the event of a termination of employment, or under which the Executive had agreed, prior to the Applicable Trigger Date, to terminate his or her employment.

2.2. Eligibility Under Section 4. Subject to Section 2.1, each Executive shall be eligible for the benefits provided under Section 4 hereof in the event such Executive has a Termination of Employment; provided, however, that any Executive whose Termination of Employment is covered under Section 5 hereof or a change in control agreement entered into between such Executive and the Company (an " Individual Change in Control Agreement"), or who is an interim employee separating under the change in control provisions of another severance plan, shall not be eligible for benefits under Section 4, except as expressly provided in Section 5 or such Individual Change in Control Agreement (which expressly refers to the benefits under Section 4 of this Plan).

2.3. Eligibility Under Section 5. Eligibility for the benefits provided under Section 5 hereof due to a Termination of Employment during a Post-Change Period or an Imminent Control Change Period shall be subject to Section 2.1, and shall be limited to persons who are Executives immediately prior to the Applicable Trigger Date and who are not subject to Individual Change in Control Agreements.

3. **PARTICIPATION**

Each eligible Executive shall become a participant in the Plan ("Participant") upon his or her execution of a separation agreement with the Company in such form as the Company, in its sole discretion, shall require or permit (the "Severance Agreement"), provided such Severance Agreement is executed not later than 45 days after the Executive's Termination Date. Notwithstanding anything herein to the contrary, each Executive shall also be required to execute, not later than 45 days after the Executive's Termination Date, a waiver and release of claims against the Company ("Waiver and Release") which is substantially in the form attached hereto and made a part hereof as Exhibit II, as may from time to time be modified by the Company in its sole discretion. Such Waiver and Release shall also include, with respect to an executive who was employed by Constellation Energy Group, Inc., or its subsidiary or affiliate (collectively, "Constellation") immediately prior to March 12, 2012, a release of any and all claims for additional severance, incentive and change in control payments or benefits of any kind (other than any previous vesting of equity awards). An Executive's right to the payments and benefits under this Plan shall be contingent upon (a) Executive having timely executed and delivered to the Company the Severance Agreement, Waiver and Release and Restrictive Covenants, (b) Executive not revoking the Waiver and Release and (c) Executive not violating any of Executive's on-going obligations under the Plan, the Waiver and Release and the Restrictive Covenants. To the extent that the Company makes payments and provides benefits to an Executive prior to receipt of the Waiver and Release and/or the expiration of the revocation period and the Executive either does not timely execute and deliver the Waiver and Release to the Company or revokes the Waiver and Release in accordance with its terms, Executive shall pay to the Company within 10 days following the expiration of the 45-day consideration period or the date such release was revoked, a lump sum payment of all payments and the value of all benefits received by Executive to date hereunder.

4. **BENEFITS**

A Participant described in Section 2.2 shall be entitled to all Accrued Obligations and, subject to Section 6, benefits pursuant to this Section 4 upon the Participant's Termination of Employment.

4.1. Severance Pay.

(a) In General. Each Participant other than a Participant described in Section 4.1(b) shall receive severance pay at a monthly rate equal to 1/12 of the sum of (a) the Participant's annual base salary in effect as of the date of Termination of Employment, plus, if the Executive is a participant in the Annual Incentive Award Plan with respect to the year in which the Termination Date occurs, (b) the Severance Incentive. Subject to Section 13.13 below, payment shall be made in regular payroll installments for the duration of the applicable Salary Continuation Period, as indicated below, commencing no later than the second paydate which occurs after the Participant's Termination Date. Payment will be made in accordance with the Company's normal payroll practices, net of applicable taxes and other deductions.

Participant Level	Salary Continuation Period
Senior Executive Management	24 months
Senior Vice Presidents of Exelon	18 months
Other Executives	15 months

(b) Participants Employed for Less Than Two Years. Each Participant who has been continuously employed by the Company for less than twenty-four months as of the Participant's Termination Date shall receive severance pay at a monthly rate equal to 1/12 of the Participant's annual base salary in effect as of the Termination Date. Subject to Section 13.13 below, payment shall be made in regular payroll installments for the duration of the applicable Salary Continuation Period, as indicated below, commencing no later than the second paydate which occurs after the Participant's Termination Date. Payment will be made in accordance with the Company's normal payroll practices, net of applicable taxes and other deductions.

Participant Level	Salary Continuation Period
Senior Executive Management	18 months (12 months if employed < 12 months)
Other Executives	12 months (6 months if employed < 12 months)

4.2. Annual Incentive Awards. Each Participant who is a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs shall receive an Annual Incentive which shall be prorated by multiplying the amount of such Annual Incentive by a fraction the numerator of which is the number of days elapsed during such year as of the Participant's Termination Date and the number of days in the year in which Termination Date occurs. Payment of Annual

Incentives under this Section 4.2 shall be made in a lump sum net of applicable taxes and other deductions at the time awards under the Annual Incentive Award Plan are paid to active employees for such performance period (but not later than March 15 of the year following the last day of such performance period), and shall be considered a "short-term deferral" within the meaning of Section 409A of the Code. A Participant who is not a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs shall not be entitled to an Annual Incentive, and the amount (if any) payable under any other Incentive Plan for such year shall be determined by the Company in its sole discretion.

4.3. Stock Options. No Participant shall be entitled to participate in any new grants of Stock Options (as defined in Section 5.1(b)) made after such Participant's notification of his or her Termination of Employment. Except as provided below, any Stock Options previously granted to the Participant shall be exercisable only to the extent such Stock Options are exercisable as of the date of such Participant's Termination Date and shall thereafter be exercised in accordance with the provisions of the LTIP. Stock Options which remain unexercisable as of the Participant's Termination Date shall be forfeited. Notwithstanding the preceding, if, as of the last day of the Salary Continuation Period, such Participant has attained at least age 50 (age 55 with respect to Stock Options granted on or after January 1, 2013) and completed at least 10 years of service as defined under the tax-qualified defined benefit plan maintained by Exelon in which the Executive is a participant (the " Pension Plan") or SERP, then any Stock Options granted to such Participant which have not become exercisable prior to the Participant's Termination Date shall (i) become fully vested, and (ii) remain exercisable until the fifth anniversary of the Termination Date or, if earlier, the option expiration date, provided that this Section 4.3 shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

4.4. Other Awards. Awards of Performance Shares, Restricted Stock (as defined in Sections 5.1(c) and 5.1(d), respectively) and/or Cash Performance Awards, as applicable, shall be payable to a Participant solely to the extent provided under the terms of such awards and the applicable plan under which such awards are granted; provided, however, that to the extent the Company determines that a Participant is a Specified Employee and that any such payment is deferred compensation, each within the meaning of Section 409A of the Code, such payment shall not be made prior to the earlier to occur of (i) the six-month anniversary of the Termination Date or (ii) the date of the Participant's death.

4.5. Health Care Coverage. During the Salary Continuation Period, a Participant (and his or her dependents) shall be eligible to participate in the health care plans under which they were covered immediately prior to his or her Termination of Employment, in accordance with and subject to the terms and conditions of such plans as in effect from time to time. The Participant's out of pocket costs (including premiums, deductibles and co-payments) for such coverage shall be the same as that in effect from time to time for active peer employees during such period. Coverage under this Paragraph 4.5 shall be provided for the duration of the Salary Continuation Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA") for the same period. At the end of the Salary Continuation Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any; provided, however that a Participant who, as of the last day of the Salary Continuation Period, has attained at least age 50 and completed at least 10 years of service (or who has completed such other age and service requirement then in effect under the Exelon Corporation Severance Benefit Plan or any successor plan as of the relevant time set forth in such plan) under the terms of the Pension Plan (or who, pursuant to the terms of an offer of employment or employment agreement or under any provision of the Pension Plan or SERP, is credited with a number of additional years of age and/or service that would enable such Participant to satisfy the above eligibility requirements) shall be entitled to elect such Company group health care programs for retirees as are in effect as of the Termination Date and are applicable to such Participant by the programs' eligibility terms and conditions as though such Participant had attained such programs' age and service requirements. The eligibility for coverage and availability of programs or plans, the amounts charged for coverage, and the other terms, conditions and limitations under the Company's group health care programs or plans shall remain subject to the Company's right to amend, change or terminate such programs or plans at any time.

4.6. SERP / Other Deferred Compensation. For purposes of the Participant's SERP benefit, the Salary Continuation Period shall be taken into account as service solely for purposes of determining whether the Participant is vested (i.e., 3 or 5 years of service) and, to the extent relevant under the Pension Plan covering the Participant, the amount of the Participant's regular accrued benefit, but not for purposes of determining eligibility for early retirement benefits (including any social security supplement) or any other purpose. In determining the amount of the Participant's vested benefit, if any, the severance payments made under Section 4.1 shall be taken into account as if such payments were normal base salary and incentive payments. Payment shall be made in accordance with the SERP and the Participant's distribution election in effect thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election applicable to the Participant). All amounts previously deferred by, or accrued to the benefit of, such Participant under the Exelon Corporation Deferred Compensation Plan, the Exelon Corporation Stock Deferral Plan or the Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan shall, to the extent vested, be paid in accordance with the Participant's distribution election in effect thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election applicable to the Participant).

4.7. Life Insurance and Disability Coverage. A Participant shall be eligible for continued coverage under the applicable life insurance and long term disability plans sponsored by the Company (or other equivalent coverage or benefits) shall be extended to each Participant through the last day of the Salary Continuation Period applicable to such Participant on the same terms and subject to the same terms and conditions as are applicable to active peer employees (including, without limitation, submission of proof by an Executive who seeks long term disability benefits that such Executive would have satisfied the conditions for such benefits had the Executive been an employee during the Salary Continuation Period and terminated employment on or before the last day of such period).

4.8. Executive Perquisites. Executive perquisites shall terminate effective as of the Participant's Termination Date, and any Company-owned property shall be required to be returned to the Company no later than such date.

4.9. Outplacement Services. Each Participant shall be entitled to outplacement services at the expense of the Company for twelve months and subject to such terms and conditions as the Plan Administrator, in its sole discretion, determines are appropriate. No cash shall be paid in lieu of such fees and costs.

4.10. Restrictions on In-Kind Benefits. The in-kind benefits provided under each of Sections 4.5, 4.7 and 4.8 during any calendar year shall not affect the benefits to be provided under such section in any subsequent calendar year. The right to such benefits shall not be subject to liquidation or exchange for any other benefit

4.11. Other Coverage. Notwithstanding the foregoing, if such Participant is eligible to obtain a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall promptly notify the Plan Administrator of any such coverage.

5. CHANGE IN CONTROL BENEFITS

A Participant described in Section 2.3 shall be entitled to all Accrued Obligations and, subject to Section 6, benefits pursuant to this Section 5 if such a Participant has a Termination of Employment during a Post-Change Period or Imminent Control Change Period, and such Participant shall not be eligible for benefits under Section 4 unless so expressly provided in this Section 5.

5.1. Termination During a Post-Change Period. If, during a Post-Change Period, an eligible Executive has a Termination of Employment and becomes a Participant, the Company's sole obligations under Section 4 and Sections 5.1 and 5.2 shall be as set forth in this Section 5.1 (subject to Sections 5.3, 5.5, 5.6 and 6.0.

(a) Severance Payments. The Company shall pay or provide (or cause to be provided) to such Participant, according to the payment terms set forth in Section 5.3 below, the following:

(i) Annual Incentive for Year of Termination. An amount equal to the Annual Incentive applicable to such Participant under the Incentive Plan for the performance period in which the Termination Date occurs;

(ii) Deferred Compensation and Non-Qualified Defined Contribution Plans . All amounts previously deferred by, or accrued to the benefit of, such Participant under the Exelon Corporation Deferred Compensation Plan, the Exelon Corporation Stock Deferral Plan or the Constellation Energy Group Inc. Deferred Compensation Plan, any successor plan, or under any other non-qualified defined contribution or deferred compensation plan of the Company, whether vested or non-vested, together with any accrued earnings thereon, to the extent that such amounts and earnings have not been previously paid by the Company and are not provided under the terms of any such non-qualified plan;

(iii) SERP Enhancement. An amount payable under the SERP equal to the positive difference, if any, between:

(1) the lump sum value of such Participant's benefit, if any, under the SERP, calculated as if such Participant had:

(a) become fully vested in all Pension Plan and SERP benefits,

(b) to the extent age is relevant under the Pension Plan covering the Participant, attained as of the Termination Date an age that is two years greater than such Participant's actual age and that includes the number of years of age credited to such Participant pursuant to any other agreement between the Company and such Participant,

(c) to the extent service is relevant under the Pension Plan covering the Participant, accrued a number of years of service (for purposes of determining the amount of such benefits, entitlement to—but not commencement of—early retirement benefits, and all other purposes of the Pension Plan and SERP) that is two years greater than the number of years of service actually accrued by such Participant as of the Termination Date and that includes the number of years of service credited to such Participant pursuant to any other agreement between the Company and such Participant, and

(d) received the severance benefits specified in Sections 5.1(a)(i) and 5.1(a)(v) as covered compensation in regular installments during the Severance Period, minus

(2) the aggregate amounts paid or payable to such Participant under the SERP;

(iv) Non-vested Benefits Under Pension Plan. An amount equal to the actuarial equivalent present value of any non-vested portion of such Participant's accrued benefit under the Pension Plan as of the Termination Date and forfeited by such Participant by reason of the Termination of Employment; and

(v) Multiple of Salary and Severance Incentive. An amount equal to two (2) times the sum of (x) the Participant's Base Salary plus, if the Participant is a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs, (y) the Severance Incentive, net of applicable taxes and other deductions.

(b) Stock Options. Each of such Participant's stock options granted under the LTIP ("Stock Options") shall (i) become fully vested, and (ii) remain exercisable until the fifth anniversary of the Termination Date or, if earlier, the expiration date of any such Stock Option, provided that this Section 5.1(b) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(c) Performance Share Vesting. On the Termination Date, all of the performance share units granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP ("Performance Shares") prior to January 1, 2013 to the extent earned by and awarded to such Participant (i.e. as to which the applicable performance cycle has elapsed) as of the Termination Date, shall become fully vested at the actual level earned and awarded, and, to the extent not yet earned by and awarded to such Participant (i.e. as to which the current performance cycle has not elapsed) as of the Termination Date, shall become fully vested at the earned level determined as of the last day of the applicable performance cycle. With respect to all Performance Shares granted on or after January 1, 2013, such Performance Shares shall become vested and earned as set forth in the LTIP, as if the Executive had been involuntarily terminated without cause.

(d) Other Awards. All forfeiture conditions that as of the Termination Date are applicable to any shares of restricted stock or restricted stock units awarded to such Participant by Exelon other than under the Exelon Long Term Performance Share Award Program under the LTIP ("Restricted Stock") shall (except as expressly provided to the contrary in the applicable awards) lapse immediately and all such awards will become fully vested. All Cash Performance Awards shall become fully vested in accordance with their terms.

(e) Continuation of Welfare Benefits. During the Severance Period, the Executive and the Executive's dependents shall be eligible for participation in the Company's welfare plans, including medical, prescription, dental, disability, employee life, group life and accidental death benefits but excluding any severance pay ("Welfare Plans") that covered the Participant or such Participant's dependents as of the Termination Date, in accordance with the terms and conditions of such plans and applicable law. Such provision of welfare benefits shall be subject to the following:

(i) In determining benefits applicable under such Welfare Plans, such Participant's annual compensation attributable to base salary and incentives for any plan year or calendar year, as applicable, shall be deemed to be not less than such Participant's Base Salary and annual incentive for the year in which the Termination Date occurs.

(ii) The cost of such welfare benefits to such Participant and dependents under this Section 5.1(e) shall not exceed the cost of such benefits to peer executives who are actively employed during the Severance Period.

(iii) Health care coverage under this Section 5.1(e) shall be provided for the duration of the Severance Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA ("COBRA") for the same period. At the end of the Severance Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any, at the Participant's sole expense.

(iv) If such Participant has, as of the last day of the Severance Period, attained age 50 and completed at least 10 years of service with the Company, such Participant shall be entitled to elect coverage under such Company group health care programs for retirees as are in effect as of the Termination Date and are applicable to such Participant by the programs' eligibility terms and conditions as though such Participant had attained such programs' age and service requirements ; provided, however, that for purposes hereof, any years of age and/or credited service granted to such Participant in any other plan or agreement between such Participant and the Company shall be taken into account. For purposes of determining eligibility for (but not the time of commencement of) such retiree benefits, such Participant shall also be considered (1) to have remained employed until the last day of the Severance Period and to have retired on the last day of such period, and (2) to have attained at least the age such Participant would have attained on the last day of the Severance Period. The eligibility for coverage and availability of programs or plans, the amounts charged for coverage, and the other terms, conditions and limitations under the Company's group health care programs or plans shall remain subject to the Company's right to amend, change or terminate such programs or plans at any time.

Notwithstanding the foregoing, if such Participant is eligible to obtain a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall promptly notify the Plan Administrator of any such coverage.

(f) Outplacement. To the extent actually incurred by such Participant, the Company shall pay or cause to be paid on behalf of such Participant, as incurred, all reasonable fees and costs charged by a nationally recognized outplacement firm selected by such Participant for outplacement services provided for up to 12 months after the Termination Date. No cash shall be paid in lieu of such fees and costs.

(g) Indemnification. Such Participant shall be indemnified and held harmless by the Company to the greatest extent permitted under applicable law and the Company's by-laws if such Participant was, is, or is threatened to be, made a party to any pending, completed or threatened action, suit, arbitration, alternate dispute resolution mechanism, investigation, administrative hearing or any other proceeding brought by a third party (and not by or on behalf of the Company or its shareholders) whether civil, criminal, administrative or investigative, and whether formal or informal, by reason of the fact that such Participant is or was, or had agreed to become, a director, officer, employee, agent, or fiduciary of the Company or any other entity which such Participant is or was serving at the request of the Company ("Proceeding"), against all expenses (including all reasonable attorneys' fees) and all claims, damages, liabilities and losses incurred or suffered by such Participant or to which such Participant may become subject for any reason; provided, that the Participant provides the Company written notice of any such Proceeding promptly after receipt and such that the Company's ability to defend shall not be prejudiced in any fashion and the Company shall have the right to direct the defense, approve any settlement and shall not be required to indemnify the Participant in connection with any proceeding initiated by the Participant, including a counterclaim or crossclaim, unless such proceeding was authorized by the Company, and that the Participant fully cooperates in the investigation and defense of such Proceeding.

(h) Directors' and Officers' Liability Insurance. For a period of six years after the Termination Date, the Company shall provide such Participant with coverage under a directors' and officers' liability insurance policy in an amount no less than, and on terms no less favorable than, those provided to peer executives of the Company from time to time.

5.2. Termination During an Imminent Control Change Period. If, during an Imminent Control Change Period, a Participant has a Termination of Employment, then such Participant shall receive benefits at the time and in the manner provided in Section 4 and the Company's sole obligations to such Participant under Sections 5.1 and 5.2 shall be as set forth in this Section 5.2 (and subject to Sections 5.3, 5.5, 5.6 and 6). The Company's obligations to such Participant under this Section 5.2 shall in all events be reduced by any amounts or benefits paid or provided pursuant to Section 4.

(a) Cash Severance Payments. If the Imminent Control Change Period culminates in a Change Date, the Company shall pay (or cause to be paid) to such Participant the amounts described in Section 5.1(a)(i) through (v). Such amounts shall be paid to such Participant as described in Section 5.3, provided that amounts that would have been paid prior to the Change Date shall be paid in a lump sum (without interest) within 30 business days after the Change Date.

(b) Vested Stock Options. Such Participant's Stock Options, to the extent vested on the Termination Date,

(i) will not expire (unless such Stock Options would have expired had such Participant remained an employee of the Company) during the Imminent Control Change Period; and

(ii) will continue to be exercisable after the Termination Date to the extent provided in the applicable grant agreement or the LTIP, and thereafter such Stock Options shall not be exercisable during the Imminent Control Change Period.

If the Imminent Control Change Period lapses without a Change Date, then such Participant's Stock Options, to the extent vested on the Termination Date, may be exercised, in whole or in part, during the 30-day period following the lapse of the Imminent Control Change Period, or, if longer, the period during which such Participant's vested Stock Options could otherwise be exercised under the terms of the applicable grant agreement or the LTIP (but in no case shall any Stock Options remain exercisable after the date on which such Stock Options would have expired if such Participant had remained an employee of the Company).

If the Imminent Control Change Period culminates in a Change Date, then effective upon the Change Date, such Participant's Stock Options, to the extent vested on the Termination Date, may be exercised in whole or in part by such Participant at any time until the earlier of the fifth anniversary of the Change Date or the option expiration date for such Stock Options, provided that this Section 5.2(b) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(c) Non-vested Stock Options. Such Participant's Stock Options that are not vested on the Termination Date:

(i) will not expire (unless such Stock Options would have expired had such Participant remained an employee of the Company) during the Imminent Control Change Period; and

(ii) will not continue to vest and will not be exercisable during the Imminent Control Change Period.

If the Imminent Control Change lapses without a Change Date, such non-vested Stock Options will thereupon expire.

If the Imminent Control Change culminates in a Change Date, then immediately prior to the Change Date, such non-vested Stock Options shall become fully vested, and may thereupon be exercised in whole or in part by such Participant at any time until the earlier of the fifth anniversary of the Change Date, or the option expiration date for such Stock Options, provided that this Section 5.2(c) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(d) Performance Shares. Such Participant's Performance Shares granted under the Exelon Long Term Performance Share Award Program under the LTIP will not be forfeited during the Imminent Control Change Period, and will not continue to vest during the Imminent Control Change Period. If the Imminent Control Change lapses without a Change Date, such Performance Shares shall be governed according to the terms of Section 4. If the Imminent Control Change Period culminates in a Change Date:

(i) All Performance Shares granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP prior to January 1, 2013, which, as of the Termination Date, have been earned by and awarded to such Participant, shall become fully vested at the actual earned level on the Change Date, and

(ii) All of the Performance Shares granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP prior to January 1, 2013 which, as of the Termination Date, have not been earned by and awarded to such Participant shall become fully vested on the Change Date at the actual earned level as of the last day of the applicable performance cycle, and

(iii) With respect to all Performance Shares granted on or after January 1, 2013, such Performance Shares shall become vested and earned as set forth in the LTIP, as if the Executive had been involuntarily terminated without cause.

(e) Restricted Stock. Such Participant's non-vested Restricted Stock will:

(i) not be forfeited during the Imminent Control Change Period; and

(ii) not continue to vest during the Imminent Control Change Period.

If the Imminent Control Change Period lapses without a Change Date, such non-vested Restricted Stock shall thereupon be forfeited.

If the Imminent Control Change Period culminates in a Change Date, then immediately prior to the Change Date, such Participant's Restricted Stock shall (except as expressly provided to the contrary in the award) become fully vested, and within ten business days after the Change Date, the Company shall deliver to such Participant all of such shares theretofore held by or on behalf of the Company, which will be subject to the same terms which other stockholders of the Company receive in the transaction.

(f) Cash Performance Awards. All Cash Performance Awards shall become fully vested in accordance with the terms of the underlying award documents.

(g) Continuation of Welfare Benefits. The Participant and the Participant's dependents shall be eligible for welfare benefits (other than any severance pay that may be considered a welfare benefit) in accordance with the terms and conditions of the applicable plans during the Imminent Control Change Period, to the same extent as if such Participant had remained employed during such period, subject to the following:

(i) in determining benefits applicable under such Welfare Plans, such Participant's annual compensation attributable to base salary and incentives for any plan year or calendar year, as applicable, shall be deemed to be not less than such Participant's Base Salary and annual incentive for the year in which the Termination Date occurs;

(ii) the cost of such welfare benefits to such Participant and dependents under this Section 5.2(g) shall not exceed the cost of such benefits to peer executives who are actively employed by the Company during the Imminent Control Change Period; and

(iii) Health care coverage under this Section 5.2(g) shall be provided for the duration of the Severance Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA") for the same period. At the end of the Severance Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any.

If the Imminent Control Change Period lapses without a Change Date, welfare benefit plan coverage under this Section 5.2(g) shall thereupon cease, subject to such Participant's rights, if any, to continued coverage under a Welfare Plan, Section 4, or applicable law. If the Imminent

Control Change Period culminates in a Change Date, then for the remainder of the Severance Period, the Participant and his or her dependents shall continue to be eligible for welfare benefits as described in, and subject to the limitations of Section 5.1(e).

Notwithstanding the foregoing, if such Participant obtains a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall immediately notify the Plan Administrator of any such coverage.

(h) Indemnification. Such Participant shall be indemnified and held harmless by the Company to the same extent as provided in Section 5.1(g), but only during the Imminent Control Change Period (or greater period provided under the Company's by-laws) if the Imminent Control Change Period lapses without a Change Date.

(i) Termination During an Imminent Control Change Period: Directors' and Officers' Liability Insurance . The Company shall provide the same level of directors' and officers' liability insurance for such Participant as provided in Section 5.1(h), but only during the Imminent Control Change Period (or greater period provided under the Company's by-laws) if the Imminent Control Change Period lapses without a Change Date.

5.3. Timing of Severance Payments. Unless otherwise specified herein, the Accrued Obligations and the amount described in Section 5.1(a)(i) shall be paid within 30 business days of the Termination Date, and such amounts shall be considered "short-term deferrals" within the meaning of Section 409A of the Code. The amounts described in Sections 5.1(a)(ii), (iii) and (iv) shall be paid in accordance with the applicable deferred compensation plan or the SERP and the Participant's distribution election thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election in effect with respect to the Participant as of such date). Subject to Section 13.13, the severance payments described in Section 5.1(a)(v) shall be paid during the Severance Period, beginning no later than the second paydate which occurs after the Termination Date, in periodic payments to a Participant according to the Company's normal payroll practices at a monthly rate equal to 1/12 of the sum of (i) such Participant's Base Salary plus (ii) the Severance Incentive (if any). The in-kind benefits and reimbursements provided under each of Sections 5.1(e), 5.1(h), 5.2(g) and 5.2(i) during any calendar year shall not affect the benefits or reimbursements to be provided under such section in any subsequent calendar year. The right to such benefits and reimbursements shall not be subject to liquidation or exchange for any other benefit.

5.4. Other Terminations of Employment by the Company or a Participant.

(a) Obligations. If, during a Post-Change Period or an Imminent Control Change Period, (i) the Company terminates an eligible Executive's employment for Cause (or causes a Participant to be terminated for Cause) (" Cause Termination") or disability (as determined by the Plan Administrator in good faith), (ii) an Executive elects to retire or otherwise terminate employment other than for Good Reason, disability or death, or (iii) an eligible Executive's employment terminates on account of death, the Company shall have no obligations to such Executive under Section 5. The remaining applicable provisions of this Plan (including the Restrictive Covenants) shall continue to apply.

(b) Procedural Requirements. The Company shall strictly observe or cause to be strictly observed each of the following procedures in connection with any Cause Termination during a Post-Change Period or an Imminent Control Change Period: an eligible Executive's termination of employment shall not be deemed to be for Cause under this Section 5.4 unless and until there shall have been delivered to such Executive a written notice of the determination of the Chief Executive Officer of the Executive's employer (" CEO") (after reasonable written notice of such consideration by the CEO of acts or omissions alleged to constitute Cause is provided to such Executive and such Executive is given an opportunity to present a written response to the CEO regarding such allegations), finding that, in his or her good faith opinion, such Executive's acts, or failure to act, constitutes Cause and specifying the particulars thereof in detail.

5.5. Sole and Exclusive Obligations. The obligations of the Company under this Plan with respect to any Termination of Employment occurring during a Post-Change Period or Imminent Control Change Period shall supersede any severance obligations of the Company in any other plan of the Company or agreement between such Participant and the Company, including, without limitation, Section 4, any offer of employment or employment contract of the Company which provides for severance benefits, except as explicitly provided in Section 5.2 or to the extent such Participant is ineligible for such benefits or such benefits are waived pursuant to Section 2.1.

5.6. Payment Capped. If at any time or from time to time, it shall be determined by the Company's independent auditors that any payment or other benefit to a Participant pursuant to Section 4 or 5 of this Plan or otherwise (" Potential Parachute Payment") is or will become subject to the excise tax imposed by Section 4999 of the Code or any similar tax payable under any United States federal, state, local, foreign or other law (" Excise Taxes"), then the Potential Parachute Payments payable to such Participant shall be reduced to the largest amount which would both (a) not cause any Excise Tax to be payable by such Participant and (b) not cause any Potential Parachute Payments to become nondeductible by the Company by reason of Section 280G of the Code (or any successor provision).

6. <u>TERMINATION OF PARTICIPATION; CESSATION OF BENEFITS</u>

A Participant's benefits under Section 4 of the Plan shall terminate on the last day of the Participant's Salary Continuation Period; provided that a Participant's right to benefits shall terminate immediately on such date as the Company discovers that the Participant has breached any of the Restrictive Covenants or the Waiver and Release, or if at any time the Company determines that in the course of his or her employment the Executive engaged in conduct described in Section 7.11(b), (c), (d) or (e) or the Executive fails to comply with Section 13.2, in which case the Company may require the repayment of amounts paid pursuant to Section 4.1 prior to such breach or other conduct, and shall discontinue the payment of any additional amounts under Section 4 of the Plan.

A Participant's benefits under Section 5 of the Plan shall terminate on the later of the last day of the Participant's Severance Period or the date all benefits to which the Participant is entitled to have been paid from the Plan; provided that a Participant's right to benefits shall terminate immediately on the date the Company discovers that the Participant has breached any of the Restrictive Covenants or the Waiver and Release, or if at any time the Company determines, in accordance with the procedural requirements set forth in Section 5.4(b) that in the course of his or her employment the Executive engaged in conduct described in Section 7.11(b), (c), (d) or (e) or the Executive fails to comply with Section 13.2, in which case the Company may require the repayment of amounts paid pursuant to Section 5 prior to such breach or other conduct, and shall discontinue the payment of any additional amounts under Section 5 of the Plan.

Benefits paid or payable to a Participant under Section 4 and Section 5 of the Plan shall be subject to any executive or officer incentive compensation recoupment policy of the Board of Directors as in effect as of the Termination Date.

7. <u>DEFINITIONS</u>

In addition to terms previously defined, when used in the Plan, the following capitalized terms shall have the following meanings unless the context clearly indicates otherwise:

7.1. "<u>Accrued Annual Incentive</u>" means the amount of any annual incentive earned but not yet paid with respect to the Company's latest fiscal year ended prior to the Termination Date.

7.2. "<u>Accrued Base Salary</u>" means the amount of a Participant's Base Salary that is accrued but not yet paid as of the Termination Date.

7.3. "<u>Accrued Obligations</u>" means, as of any date, the sum of a Participant's Accrued Base Salary, Accrued Annual Incentive and any accrued but unpaid paid time off

7.4. "<u>Annual Incentive</u>" as of a certain date means an amount to which a Participant would have been entitled under the Annual Incentive Award Plan (or, with respect to a termination pursuant to Section 5, such other Incentive Plan applicable to such Participant) for the applicable performance period based on the actual achievement performance goals established pursuant to such plan as of the end of the applicable performance period had the Participant remained employed through the last day of such period; provided, however, that any reduction in a Participant's Base Salary or annual incentive that would qualify as Good Reason shall be disregarded for purposes of this definition

7.5. "Annual Incentive Award Plan", means the Exelon Corporation Annual Incentive Award Plan, or any successor plan thereto (including but not limited to any annual incentive plan of a successor to a Company pursuant to a Change in Control).

7.6. "Applicable Trigger Date" means

(a) the Change Date, with respect to a Post-Change Period; or

(b) the date of an Imminent Control Change, with respect to the Imminent Control Change Period.

7.7. "Base Salary" for purposes of Section 5, means not less than 12 times the highest monthly base salary paid or payable to a Participant by the Company in respect of the 12-month period immediately before the Applicable Trigger Date.

7.8. "Beneficial Owner" means such term as defined in Rule 13d-3 of the SEC under the Exchange Act.

7.9. "Board" means the Board of Directors of Exelon or, from and after the effective date of a Corporate Transaction (as defined in the definition of Change in Control), the Board of Directors of the corporation resulting from a Corporate Transaction or, if securities representing at least 50% of the aggregate voting power of such resulting corporation are directly or indirectly owned by another corporation, such other corporation.

7.10. "Cash Performance Award" means any cash performance award granted to a Participant in lieu of an award of Performance Shares or Restricted Stock under the LTIP during employment by Commonwealth Edison Company.

7.11. "Cause" means, with respect to any Executive:

(a) the refusal to perform or habitual neglect in the performance of the Executive's duties or responsibilities, or of specific directives of the officer or other executive of Exelon or any of its affiliates to whom the Executive reports which are not materially inconsistent with the scope and nature of the Executive's employment duties and responsibilities;

(b) an Executive's willful or reckless commission of act(s) or omission(s) which have resulted in or are likely to result in, a material loss to, or material damage to the reputation of, Exelon or any of its affiliates, or that compromise the safety of any employee or other person;

(c) the Executive's commission of a felony or any crime involving dishonesty or moral turpitude;

(d) an Executive's material violation of Exelon's or any of its affiliate's Code of Business Conduct (including the corporate policies referenced therein) which would constitute grounds for immediate termination of employment, or of any statutory or common law duty of loyalty to Exelon or any of its affiliates; or

(e) any breach by the Executive of any one or more of the Restrictive Covenants.

7.12. "Change Date" means each date on which a Change in Control occurs after the Effective Date.

7.13. "Change in Control" means:

(a) any SEC Person becomes the Beneficial Owner of 20% or more of the then outstanding common stock of Exelon or of Voting Securities representing 20% or more of the combined voting power of all the then outstanding Voting Securities of Exelon (such an SEC Person, a "20% Owner"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change in Control: (1) any acquisition directly from Exelon (excluding any acquisition resulting from the exercise of an exercise, conversion or exchange privilege unless the security being so exercised, converted or exchanged was acquired directly from Exelon), (2) any acquisition by Exelon, (3) any acquisition by an employee benefit plan (or related trust) sponsored or maintained by Exelon or any corporation controlled by Exelon (a "Company Plan"), or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this definition; provided further, that for purposes of clause (2), if any 20% Owner of Exelon other than Exelon or any Company Plan becomes a 20% Owner by reason of an acquisition by Exelon, and such 20% Owner of Exelon shall, after such acquisition by Exelon, become the beneficial owner of any additional outstanding common shares of Exelon or any additional outstanding Voting Securities of Exelon (other than pursuant to any dividend reinvestment plan or arrangement maintained by Exelon) and such beneficial ownership is publicly announced, such additional beneficial ownership shall constitute a Change in Control; or

(b) Individuals who, as of the date hereof, constitute the Board (the " Incumbent Board") cease for any reason to constitute at least a majority of the Incumbent Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by Exelon's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest (as such terms are used in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation ("Merger"), or the sale or other disposition of more than 50% of the operating assets of Exelon (determined on a consolidated basis), other than in connection with a sale-leaseback or other arrangement resulting in the continued utilization of such assets (or the operating products of such assets) by Exelon (such reorganization, merger, consolidation, sale or other disposition, a "Corporate Transaction"); excluding, however, a Corporate Transaction pursuant to which:

(i) all or substantially all of the individuals and entities who are the Beneficial Owners, respectively, of the outstanding common stock of Exelon and outstanding Voting Securities of Exelon immediately prior to such Corporate Transaction beneficially own, directly or indirectly, more than 60% of, respectively, the then-outstanding shares of common stock and the combined voting power of the then-outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Corporate Transaction (including, without limitation, a corporation which, as a result of such transaction, owns Exelon or all or substantially all of the assets of Exelon either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Corporate Transaction of the outstanding common stock of Company and outstanding Voting Securities of Exelon, as the case may be;

(ii) no SEC Person (other than the corporation resulting from such Corporate Transaction, and any Person which beneficially owned, immediately prior to such corporate Transaction, directly or indirectly, 20% or more of the outstanding common stock of Exelon or the outstanding Voting Securities of Exelon, as the case may be) becomes a 20% Owner, directly or indirectly, of the then-outstanding common stock of the corporation resulting from such Corporate Transaction or the combined voting power of the outstanding voting securities of such corporation; and

(iii) individuals who were members of the Incumbent Board will constitute at least a majority of the members of the board of directors of the corporation resulting from such Corporate Transaction; or

(d) Approval by Exelon's shareholders of a plan of complete liquidation or dissolution of Exelon, other than a plan of liquidation or dissolution which results in the acquisition of all or substantially all of the assets of Exelon by an affiliated company.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to a Participant if, in advance of such event, such Participant agrees in writing that such event shall not constitute a Change in Control.

7.14. "Code" means the Internal Revenue Code of 1986, as amended.

7.15. "ComEd Key Manager Plan" means the ComEd Key Manager Long-Term Performance Plan, or any successor thereto.

7.16. "ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

7.17. "Exchange Act" means the Securities Exchange Act of 1934, as amended.

7.18. "Good Reason" means:

(a) for purposes of Section 4 hereof,

(i) a material reduction of an Executive's salary unless such reduction is part of a policy, program or arrangement applicable to peer executives of the Company or of the Executive's business unit; and

(ii) with respect to an Executive whose title with respect to a Company is Senior Vice President or above, a material adverse reduction in the Executive's position or duties that is not applicable to peer executives of the Company or of the Executive's business unit, but excluding any change (A) resulting from a reorganization or realignment of all or a significant portion of the business, operations or senior management of the Company or of the business unit that employs the Executive or (B) that generally places the Executive in substantially the same level of responsibility. Notwithstanding the foregoing, no change in the position or level of officer to whom an Executive reports shall constitute grounds for Good Reason.

(b) for purposes of Section 5 hereof, the occurrence of any one or more of the following actions or omissions that occurs during a Post-Change Period or an Imminent Control Change Period:

(i) a material reduction of an Executive's salary, incentive compensation opportunity or aggregate benefits unless such reduction is part of a policy, program or arrangement applicable to peer executives (including peer executives of any successor to Exelon);

(ii) a material adverse reduction in the Executive's position, duties or responsibilities (excluding a change in the position or level of officer to whom the Executive reports), unless such reduction is part of a policy, program or arrangement applicable to peer executives (including peer executives of any successor to Exelon);

(iii) a relocation by more than 50 miles of (A) the Executive's primary workplace, or (B) the principal offices of Exelon or its successor (if such offices are such Executive's workplace), in each case without the Executive's consent; provided, however, in both cases of (A) and (B) of this subsection (b)(iv), such new location is farther from the Executive's residence than the prior location; or

(iv) a material breach of this Plan by Exelon or its successor.

(c) Application of "Good Reason" Definition During the Imminent Control Change Period . During the Imminent Control Change Period, "Good Reason" shall not include the events or conditions described in subsection (b)(i), (b)(ii) or (b)(iv) above unless the Imminent Control Change Period culminates in a Change Date.

(d) Limitations on Good Reason. Notwithstanding the foregoing provisions of this Section, no act or omission shall constitute a material breach of this Plan by Exelon, nor grounds for "Good Reason":

(i) unless the Executive gives the Plan Administrator a Notice of Termination at least 30 days prior to the Executive's Termination Date, and the Company fails to cure such act or omission within the 30-day period;

(ii) if the Executive first acquired knowledge of such act or omission more than 90 days before such Participant gives the Plan Administrator such Notice or Termination; or

(iii) if the Executive has consented in writing to such act or omission.

7.19. "Imminent Control Change" means, as of any date on or after the Effective Date and prior to the Change Date, the occurrence of any one or more of the following:

(a) Exelon enters into an agreement the consummation of which would constitute a Change in Control;

(b) Any SEC Person commences a "tender offer" (as such term is used in Section 14(d) of the Exchange Act) or exchange offer, which, if consummated, would result in a Change in Control; or

(c) Any SEC Person files with the SEC a preliminary or definitive proxy solicitation or election contest to elect or remove one or more members of the Board, which, if consummated or effected, would result in a Change in Control;

provided, however, that an Imminent Control Change will lapse and cease to qualify as an Imminent Control Change:

(i) With respect to an Imminent Control Change described in clause (a) of this definition, the date such agreement is terminated, cancelled or expires without a Change Date occurring;

(ii) With respect to an Imminent Control Change described in clause (b) of this definition, the date such tender offer or exchange offer is withdrawn or terminates without a Change Date occurring;

(iii) With respect to an Imminent Control Change described in clause (c) of this definition, (1) the date the validity of such proxy solicitation or election contest expires under relevant state corporate law, or (2) the date such proxy solicitation or election contest culminates in a shareholder vote, in either case without a Change Date occurring; or

(iv) The date a majority of the members of the Incumbent Board make a good faith determination that any event or condition described in clause (a), (b), or (c) of this definition no longer constitutes an Imminent Control Change, provided that such determination may not be made prior to the first anniversary of the occurrence of such event.

7.20. "Imminent Control Change Period" means the period commencing on the date of an Imminent Control Change, and ending on the first to occur thereafter of

(a) a Change Date, provided

(i) such date occurs no later than the first anniversary of the Termination Date, and

(ii) either the Imminent Control Change has not lapsed, or the Imminent Control Change in effect upon such Change Date is the last Imminent Control Change in a series of Imminent Control Changes unbroken by any period of time between the lapse of an Imminent Control Change and the occurrence of a new Imminent Control Change;

(b) the date an Imminent Control Changes lapses without the prior or concurrent occurrence of a new Imminent Control Change; or

(c) the first anniversary of the Termination Date.

7.21. "Incentive Plan" means the Exelon Corporation Annual Incentive Award Plan, or such other annual cash bonus arrangement of the Company in which the Executive is a participant in lieu of the Annual Incentive Award Plan, but excluding any supplemental incentive plans.

7.22. “including” means including without limitation.

7.23. “Incumbent Board”—see definition of Change in Control.

7.24. “LTIP” means the Exelon Corporation Long-Term Incentive Plan, as amended from time to time, or any successor thereto.

7.25. “LTIP Performance Period” means the performance period applicable to an LTIP award, as designated in accordance with the LTIP.

7.26. “LTIP Target Level” means, in respect of any grant of Performance Shares under the Exelon Long Term Performance Share Award Program under the LTIP, the number of Performance Shares which a Participant would have been awarded (prior to the Termination Date) for the LTIP Performance Period corresponding to such grant if the business and personal performance goals related to such grant were achieved at the 100% (target) level as of the end of the LTIP Performance Period.

7.27. “Merger”—see definition of Change in Control.

7.28. “Notice of Termination” means a written notice given by an Executive in accordance with Sections 7.18(d)(i) and 13.10 which sets forth in reasonable detail the specific facts and circumstances claimed to provide a basis for a Termination of Employment for Good Reason.

7.29. “Performance Shares”—see Section 5.1(c).

7.30. “Person” means any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporation, entity or government instrumentality, division, agency, body or department.

7.31. “Plan Administrator”—See Section 9.

7.32. “Post-Change Period” means the period commencing on a Change Date and ending on the earlier of (a) the Termination Date or (b) the second anniversary of such Change Date; provided that no duplicate benefits shall be paid with respect to simultaneous or overlapping Post-Change Periods.

7.33. “Restricted Stock”—see Section 5.1(d).

7.34. “Retiree” means a Participant who, as of his or her Termination Date, is eligible for “retirement” as defined in the LTIP.

7.35. “Salary Continuation Period” means the applicable period designated in Section 4.1 during which severance is payable.

7.36. “SEC” means the United States Securities and Exchange Commission.

7.37. "SEC Person" means any person (as such term is used in Rule 13d-5 of the SEC under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than (a) Exelon or any Person that directly or indirectly controls, is controlled by, or is under common control with, Exelon (an "Affiliate"). For purposes of this definition the term "control" with respect to any Person means the power to direct or cause the direction of management or policies of such Person, directly or indirectly, whether through the ownership of Voting Securities, by contract or otherwise, or (b) any employee benefit plan (or any related trust) of Exelon or any of its Affiliates.

7.38. "Section" means, unless the context otherwise requires, a section of this Plan.

7.39. "Senior Executive Management" means (a) an Executive whose title with respect to Exelon is Executive Vice President or above, (b) an Executive whose title with respect to a Company other than Exelon is Chief Executive Officer or President, and (c) such other Executive who was described in subparagraph (a) or (b) and has been grandfathered by the Plan Administrator.

7.40. "SERP" means the Constellation Energy Group, Inc. Benefit Restoration Plan, the PECO Energy Company Supplemental Retirement Plan or the Exelon Corporation Supplemental Executive Retirement Plan, whichever is applicable to a Participant, or any successor thereto.

7.41. "Severance Incentive" means the Target Incentive for the performance period in which the Termination Date occurs; provided, however, that for purposes of Section 5, "Severance Incentive" shall mean the greater of (a) the Target Incentive for the performance period in which the Termination Date occurs, or (b) the average of the actual Annual Incentives paid (or payable, to the extent not previously paid) to a Participant under the Annual Incentive Award Plan for each of the two calendar years preceding the calendar year in which the Termination Date occurs.

7.42. "Severance Period" means the period beginning on a Participant's Termination Date, provided such Participant's Termination of Employment entitles such Participant to benefits under Section 5.1 or 5.2, and ending on the second anniversary thereof.

7.43. "Specified Employee" means a "specified employee" within the meaning of Section 409A of the Code.

7.44. "Stock Options"—see Section 5.1(b).

7.45. "Target Incentive" as of a certain date means an amount equal to the product of Base Salary determined as of such date multiplied by the percentage of such Base Salary (if any) to which a Participant would have been entitled immediately prior to such date under the Annual Incentive Award Plan for the applicable performance period if the performance goals established pursuant to such plan were achieved at the 100% (target) level as of the end of the applicable performance period; provided, however, that any reduction in a Participant's Base Salary or annual incentive that would qualify as Good Reason shall be disregarded for purposes of this definition.

7.46. "Taxes" means the incremental federal, state, local and foreign income, employment, excise and other taxes payable by a Participant with respect to any applicable item of income.

7.47. "Termination Date" means the effective date of an eligible Executive's Termination of Employment with the Company for any or no reason, which shall be the date on which such Executive has a "separation from service," within the meaning of Section 409A of the Code; provided, however, that if the Executive terminates his or her employment for Good Reason, the Termination Date shall not be earlier than the thirtieth day following the Company's receipt of such Executive's Notice of Termination, unless the Exelon consents in writing to an earlier Termination Date.

7.48. "Termination of Employment" means:

(a) a termination of an eligible Executive's employment by the Company for reasons other than for Cause; or

(b) a resignation by an eligible Executive for Good Reason.

The following shall not constitute a Termination of Employment for purposes of the Plan: (i) a termination of employment for Cause, (ii) an Executive's resignation for any reason other than for Good Reason, (iii) the cessation of an Executive's employment with the Company or any Affiliate due to death or disability (as determined by the Plan Administrator in good faith), or (iv) the cessation of an Executive's employment with the Company or any subsidiary thereof as the result of the sale, spin-off or other divestiture of a plant, division, business unit or subsidiary or a merger or other business combination followed by employment or reemployment with the purchaser or successor in interest to the Executive's employer with regard to such plant, division, business unit or subsidiary, or an offer of employment by such purchaser or successor in interest on terms and conditions comparable in the aggregate (as determined by the Plan Administrator in its sole discretion) to the terms and conditions of the Executive's employment with the Company or its subsidiary immediately prior to such transaction.

7.49. "20% Owner"—see paragraph (a) of the definition of "Change in Control."

7.50. "Voting Securities" means with respect to a corporation, securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

8. **FUNDING**

The Plan is an unfunded employee welfare benefit plan maintained for the purpose of providing severance benefits to a select group of management or highly compensated employees. Nothing in the Plan shall be interpreted as requiring the Company to set aside any of its assets for the purpose of funding its obligations under the Plan. No person entitled to benefits under the Plan shall have any right, title or claim in or to any specific assets of the Company, but shall have the right only as a general creditor to receive benefits from the Company on the terms and conditions provided in the Plan.

9. **ADMINISTRATION OF THE PLAN**

The Plan shall be administered on a day-to-day basis by the Vice President, Corporate Compensation of Exelon (the " Plan Administrator"). The Plan Administrator has the sole and absolute power and authority to interpret and apply the provisions of this Plan to a particular circumstance, make all factual and legal determinations, construe uncertain or disputed terms and make eligibility and benefit determinations in such manner and to such extent as the Plan Administrator, in his or her sole discretion may determine. Benefits under the Plan will be paid only if the Plan Administrator, in his or her discretion, determines that an individual is entitled to them; provided, however, that any dispute after the claims procedure under Section 10 has been exhausted regarding whether an Executive's termination of employment for purposes of Section 5 is based on either Good Reason or Cause may, at the election of the Executive, be submitted to binding arbitration pursuant to Section 11.

The Plan Administrator may promulgate any rules and regulations it deems necessary to carry out the purposes of the Plan or to interpret the terms and conditions of the Plan; provided, however, that no rule, regulation or interpretation shall be contrary to the provisions of the Plan. The rules, regulations and interpretations made by the Plan Administrator shall, where appropriate, be applied on a consistent basis with respect to similarly situated Executives, and shall be final and binding on any Executive or former Executive and any successor in interest.

The Plan Administrator may delegate any administrative duties, including, without limitation, duties with respect to the processing, review, investigation, approval and payment of severance pay and provision of severance benefits, to designated individuals or committees. The Plan Administrator may amend any Participant's Severance Agreement to the extent the Plan Administrator determines it is reasonably necessary or appropriate to do so to comply with section 409A of the Code.

10. **CLAIMS PROCEDURE**

The Plan Administrator shall determine the status of an individual as an Executive and the eligibility and rights of any Executive or former Executive as a Participant to any severance pay or benefits hereunder. Any Executive or former Executive who believes that he or she is entitled to receive severance pay or benefits under the Plan, including severance pay or benefits other than those initially determined by the Plan Administrator, may file a claim in writing with the Plan Administrator. Within 90 days after the receipt of the claim the Plan Administrator shall either allow or deny the claim in writing, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as practicable, but not later than 180 days after receipt of a request for review.

A claimant whose claim is denied (or his or her duly authorized representative) may, within 60 days after receipt of the denial of his or her claim, request a review upon written application to Exelon's Chief Human Resources Officer or other officer designated by Exelon and specified in the claim denial; review (without charge) relevant documents; and submit written comments, documents, records and other information relating to the claim.

The Chief Human Resources Officer or other designated officer shall notify the claimant of his or her decision on review within 60 days after receipt of a request for review unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. Notice of the decision on review shall be in writing. The officer's decision on review shall be final and binding on any claimant or any successor in interest.

In reviewing a claim or an appeal of a claim denial, the Plan Administrator and the Chief Human Resources Officer or other designated by Exelon shall have all of the powers and authority granted to the Plan Administrator pursuant to Section 9.

11. **ARBITRATION**

Any dispute, controversy or claim between the parties hereto concerning whether an Executive's termination of employment for purposes of Section 5 is based on either Good Reason or Cause may, after the claims procedure under Section 10 has been exhausted and at the election of the Executive, be settled by binding arbitration in Chicago, Illinois, before an impartial arbitrator pursuant to the rules and regulations of the American Arbitration Association (" AAA") pertaining to the arbitration of employee benefit plan disputes. The costs and fees of the arbitrator shall be borne equally by the parties, regardless of the result of the arbitration. No arbitration shall be commenced after the date when institution of legal or equitable proceedings based upon such subject matter would be barred by the applicable statutes of limitations. Notwithstanding anything to the contrary contained in this Section or elsewhere in this Plan, any party may seek relief in the form of specific performance, injunctive or other equitable relief in order to enforce the decision of the arbitrator, and the Company may seek injunctive relief to enforce the above-referenced statutes of limitations.

12. **AMENDMENT OR TERMINATION OF PLAN**

Exelon's Chief Human Resources Officer or another designated officer of the Company may amend, modify or terminate the Plan at any time by written instrument; provided, however, that no amendment, modification or termination shall deprive any Participant of any payment or benefit that the Plan Administrator previously has determined is payable under the Plan. Notwithstanding the foregoing, no amendment or termination that reduces the severance payments or materially adversely affects any Participant's other benefits under Section 5 shall become effective as to such Participant during: (a) the 24-month period following a Change Date or (b) during an Imminent Control Change Period (unless such Participant consents to such termination or amendment). Any purported Plan termination or amendment in violation of this Section 12 shall be void and of no effect.

13. **MISCELLANEOUS**

13.1. Limitation on Rights. Participation in the Plan is limited to the individuals described in Sections 2 and 3, and the benefits under the Plan shall not be payable with respect to any voluntary or involuntary termination of employment that is not a Termination of Employment.

13.2. Cooperation By Participants. During the Salary Continuation Period or Severance Period, as applicable, the Executive shall (a) be reasonably available to the Company to respond to requests by them for information pertaining to or relating to matters which may be within the knowledge of the Executive and (b) cooperate with the Company in connection with any existing or future litigation or other proceedings brought by or against the Company, its subsidiaries or affiliates, to the extent the Company deems the Executive's cooperation reasonably necessary.

13.3. No Set-off by Company. This Section shall apply solely with respect to a Termination of Employment during a Post-Change Period or an Imminent Control Change Period that culminates in a Change Date. Except as provided in Section 6, a Participant's right to receive when due the payments and other benefits provided for under Section 5 of this Plan is absolute, unconditional and subject to no setoff, counterclaim or legal or equitable defense.

13.4. No Mitigation. A Participant shall not have any duty to mitigate the amounts payable by the Company under this Plan by seeking new employment following termination. Except as specifically otherwise provided in this Plan, all amounts payable pursuant to this Plan shall be paid without reduction regardless of any amounts of salary, compensation or other amounts which may be paid or payable to the Executive as the result of the Executive's employment by another, unaffiliated employer.

13.5. Headings. Headings of sections in this document are for convenience only, and do not constitute any part of the Plan.

13.6. Severability. If any one or more Sections, subsections or other portions of this Plan are declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not serve to invalidate any Section, subsection or other portion not so declared to be unlawful or invalid. Any Section, subsection or other portion so declared to be unlawful or invalid shall be construed so as to effectuate the terms of such Section, subsection or other portion to the fullest extent possible while remaining lawful and valid. Notwithstanding the foregoing, in the event a determination is made that the Restrictive Covenants are invalid or unenforceable in whole or in part, then the Severance Agreement with respect to the Participant subject to such determination shall be void and the Company shall have no obligation to provide benefits under this Plan to such Participant.

13.7. Governing Law. The Plan shall be construed and enforced in accordance with the applicable provisions of ERISA and Section 409A of the Code.

13.8. No Right to Continued Employment. Nothing in this Plan shall guarantee the right of a Participant to continue in employment, and the Company retains the right to terminate a Participant's employment at any time for any reason or for no reason.

13.9. Successors and Assigns. This Plan shall be binding upon and inure to the benefit of Exelon and its successors and assigns and shall be binding upon and inure to the benefit of a Participant and his or her legal representatives, heirs and legatees.

Exelon shall cause any successor to assume the Plan. No rights, obligations or liabilities of a Participant hereunder shall be assignable without the prior written consent of Exelon Corporation. In the event of the death of a Participant prior to receipt of severance pay or benefits to which he or she is entitled hereunder (and, with respect to benefits under Section 4 or Section 5, after he or she has signed the Waiver and Release), the severance pay described in Sections 4.1, 5.1, or 5.2, as applicable, shall be paid to his or her estate, and the Participant's dependents who are covered under any health care plans maintained by the Company shall be entitled to continued rights under Section 4.5 or Section 5.1(e) or Section 5.2(g), as applicable; provided that the estate or other successor of the Participant has not revoked such Waiver and Release.

13.10. Notices. All notices and other communications under this Plan shall be in writing and delivered by hand, by nationally-recognized delivery service that promises overnight delivery, or by first-class registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to a Participant, to such Participant at his most recent home address on file with the Company.

If to the Company: to the Plan Administrator.

or to such other address as either party shall have furnished to the other in writing. Notice and communications shall be effective when actually received by the addressee.

13.11. Number and Gender. Wherever appropriate, the singular shall include the plural, the plural shall include the singular, and the masculine shall include the feminine.

13.12. Tax Withholding. The Company may withhold from any amounts payable under this Plan or otherwise payable to a Participant or beneficiary any Taxes the Company determines to be appropriate under applicable law and may report all such amounts payable to such authority in accordance with any applicable law or regulation.

13.13. Section 409A. This Plan shall be interpreted and construed in a manner that avoids the imposition of additional taxes and penalties under Section 409A of the Code ("409A Penalties"). In the event the terms of this Plan would subject a Participant to 409A Penalties, the Company may amend the terms of the Plan to avoid such 409A Penalties, to the extent possible. The payments to a Participant pursuant to this Plan are intended to be exempt from Section 409A of the Code to the maximum extent possible, under either the separation pay exemption pursuant to Treasury regulation §1.409A-1(b)(9)(iii) or as a short-term deferral pursuant to Treasury regulation §1.409A-1(b)(4), and for purposes of the separation pay exemption, each installment paid to a Participant shall be considered a separate payment. Notwithstanding any other provision in this Plan, if on the date of a Participant's Termination Date the Participant is a Specified Employee, then to the extent any amount payable under this Plan constitutes the payment of nonqualified deferred compensation, within the meaning of Section 409A of the Code, that under the terms of this Plan would be payable prior to the six-month anniversary of the Termination Date, such payment shall be delayed until the earlier to occur of (A) the six-month anniversary of the Termination Date or (B) the date of the Participant's death. Any reimbursement (including any advancement) payable to a Participant pursuant to this Plan shall be conditioned on the submission by the Participant of all expense reports reasonably required by the Company under any applicable expense reimbursement policy, and shall be paid to the Participant within 30 days following receipt of such expense reports (or invoices), but in no event later than the last day of the calendar year following the calendar year in which the Participant incurred the reimbursable expense. Any amount of expenses eligible for reimbursement during a calendar year shall not affect the expenses eligibility for reimbursement during any other calendar year. The right to reimbursement pursuant to this Plan shall not be subject to liquidation or exchange for any other benefit.

EXELON CORPORATION

By: ______________________________

Amy E. Best
Senior Vice President and
Chief Human Resources Officer

Exhibit 10.64

PENSION PLAN
OF
CONSTELLATION ENERGY GROUP, INC.

(Amended and Restated Effective January 31, 2012)

PENSION PLAN

OF

CONSTELLATION ENERGY GROUP, INC.

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INTRODUCTION

The Plan, which was initially effective on January 1, 1948, was amended and restated effective January 1, 2000 to include the Pension Equity formula, and has been amended and restated from time to time thereafter. The Plan was restated on January 22, 2007, effective January 1, 2000, to incorporate all amendments made since January 1, 2000. The plan was amended and restated on January 30, 2012, effective January 31, 2012, to incorporate all amendments made since the prior restatement.

ARTICLE I—Participation

1.1 Automatic PEP Participation—Except as provided in 1.2, each Full-Time Employee of the Company, or of those subsidiaries and affiliates of the Company which are designated by the Board of Directors (as reflected in Appendix G), shall become a Participant in PEP on the date he/she becomes a Full-Time Employee. (Notwithstanding the previous sentence, effective July 23, 2010, Executive Group may designate such subsidiaries and affiliates if such designations have less than a $10 million impact on the Plan's accumulated benefit obligation per designation. At least annually, the Company's Chief Executive Officer shall report all such subsidiary and affiliate designations to the Board of Directors. An Employee classified in a job description as an On-Call Employee, a leased employee within the meaning of Code Section 414(n)(2), or a co-op, work study or summer Employee shall not become a Participant in the Plan while classified in the sole judgment of the Employer as an On-Call Employee, a leased employee, or a co-op, work study or summer Employee.

1.2 Election: Traditional Pension Plan or PEP— Each individual who is both a Participant on December 31, 1999 and an Employee on January 1, 2000 shall elect in the manner determined by the Plan Administrator to participate in either PEP or the Traditional Pension Plan. Each individual who is a Participant on December 31, 1999 and who has a Severance From Service Date on December 31, 1999, and who, at the Severance From Service Date, had attained age 55 and completed at least 20 years of Credited Service shall elect in the manner determined by the Plan Administrator to participate in either PEP or the Traditional Pension Plan. Such Participant shall make his/her election on or after January 1, 2000 and on or before the earlier of June 30, 2000 or his/her Benefit Commencement Date. The last election made on or before the earlier of June 30, 2000 or his/her Benefit Commencement Date is irrevocable, except that, in the case of a Participant whose Severance From Service Date is on or after January 1, 2000 and on or before June 30, 2000 the first election made after the Severance From Service Date is irrevocable. Any election shall be effective as of January 1, 2000. Notwithstanding anything above, any Participant who does not affirmatively make a valid election on or before June 30, 2000 will participate in PEP effective January 1, 2000.

ARTICLE II—Types of Retirement

2.1 Normal Retirement: Generally—A Participant who, on the day preceding his/her Normal Retirement Date, is actively employed or a Disabled Participant and has at least five years of Credited Service, is eligible for Normal Retirement.

2.1(a) Effective Date—Normal Retirement is effective as of the first day of the month following a Participant's Severance From Service Date, or if later, the date a Disabled Participant ceases receiving benefits under the Disability Plan.

2.2 Early Retirement: Generally—A Participant who, on his/her Severance From Service Date, is at least age 55, and has at least ten years of Credited Service, is eligible for Early Retirement.

2.2(a) Effective Date—Early Retirement is effective as of the first day of the month designated in writing by the Participant, which is after the date that the Participant becomes eligible for Early Retirement, and not later than the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month. If a written designation is not received, Early Retirement will be effective on the Participant's Normal Retirement Date.

2.3 Disability Retirement: Traditional Pension Plan—A Disabled Participant who (i) prior to receiving benefits under the Disability Plan, has at least ten years of Credited Service, and (ii) is at least age 50 but has not yet reached age 65 when he/she is determined to be no longer disabled under the terms of the Disability Plan, is eligible for Disability Retirement in the Traditional Pension Plan.

2.3(a) Effective Date—Disability Retirement in the Traditional Pension Plan is effective on the first day of the month designated in writing by the Participant, which is after the date that the Participant becomes eligible for Disability Retirement, and not later than the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month. If a written designation is not received, Disability Retirement will be effective on the Participant's Normal Retirement Date.

ARTICLE III—Pension Payments

3.1(a) Form of Pension Payments: Traditional Pension Plan—Except as provided in 3.3(h), all pension payments to Participants in the Traditional Pension Plan are paid in monthly installments.

3.1(b) Form of Pension Payments: PEP—Except as provided in 3.3(h), all pension payments to Participants in PEP are paid in monthly installments unless the Participant elects, within 60 days of the Participant's Severance From Service Date and in the manner determined by the Plan Administrator, a payment in the form of a lump sum.

3.2 Timing of Pension Payments: Traditional Pension Plan—Except as provided in 3.3(h), pension payments to Participants in the Traditional Pension Plan commence as of the applicable effective date set forth in Article II.

3.2(a) Timing of Pension Payments: PEP—Except as provided in 3.3(h), pension payments to Participants in PEP commence as of the applicable effective date set forth in Article II unless the Participant elects, within 60 days of the later of (i) the date of the letter provided by the Plan Administrator to the Participant that describes the Participant's Plan distribution options or (ii) the Participant's Severance From Service Date, and in the manner determined by the Plan Administrator, to receive a lump sum or to commence to receive monthly installments as of the first day of the month following the Participant's Severance From Service Date.

3.2(b) Timing of Pension Payments: Active Employees—Pension payments to a Participant who is an Employee and who attains age 70 ½ before January 1, 2000, shall commence on April 1 of the year following the year during which the Participant attains age 70 ½. The pension payments will be recalculated and increased if appropriate as of each January 1 (and as of the Participant's Severance From Service Date) to reflect increases in the Normal Retirement Service Percentage and changes in Final Average Pay in the case of a Participant in the Traditional Pension Plan, and to reflect increases in Total Pension Credits and changes in Final Average Annual Pay in the case of a Participant in PEP.

Pension payments to a Participant who is an Employee and who attains age 70 ½ after December 31, 1999 shall commence as of the first day of the month following the Participant's Severance From Service Date. The pension payments of a Participant in the Traditional Pension Plan will be actuarially increased to reflect the period described below during which the Participant does not receive any payments under the Plan. The period begins on the April 1 of the year following the year during which the Participant attains age 70 ½ and ends on the Benefit Commencement Date. The actuarial increase shall be calculated based on the interest rate and mortality table used in determining Present Value.

Notwithstanding the foregoing, pension payments to a Participant who owns more than 5 percent of the outstanding stock of an Employer or stock possessing more than 5 percent of the total combined voting power of all stock of an Employer, shall commence on April 1 of the year following the year during which the Participant attains age 70 ½.

The pension payments of a Participant in the Traditional Pension Plan who is employed after Normal Retirement Date shall be actuarially increased to reflect any month in which the Participant completes an hour of service described in Section 202(a)(3)(B) of ERISA on fewer than eight days. The actuarial increase shall be calculated based on the interest rate and mortality table used in determining Present Value.

Notwithstanding any provision in the Plan to the contrary, all distributions from the Plan, including distributions under Article V of the Plan, shall be made in accordance with Code Section 401(a)(9) and the regulations thereunder, including the incidental benefit requirement of Section 1.401(a)(9)-2 of the Proposed Income Tax Regulations.

3.2(c) Timing of Pension Payments: Mandatory Commencement—Notwithstanding anything in the Plan to the contrary, unless the Participant otherwise elects, pension payments to the Participant will begin not later than 60 days after the latest of the close of the Plan Year in which (i) occurs the date on which the Participant attains the earlier of age 65 or the Participant's Normal Retirement Date; (ii) occurs the 10th annual anniversary of the year in which the Participant commenced participation in the Plan; or (iii) the Participant terminates service with the Employer.

3.2(d) Cessation of Pension Payments—Except as provided in Article V, monthly pension payments shall permanently cease upon the death of the Participant, effective with the pension payment for the month following the month of the Participant's death. Monthly pension payments shall cease upon the Employer's reemployment of a Participant as an Employee. Upon the Participant's subsequent termination of employment with the Employer, the Participant's Gross Pension shall be recalculated and adjusted (including the adjustment described in 3.4(a)) and the Participant shall be given a new election with respect to the form and timing of his/her pension payments if such election otherwise would be available to the Participant.

3.3 Amount of Pension Payments—The pension payments to which a Participant is entitled are calculated based on the Participant's Gross Pension, adjusted as provided in 3.4. The calculation of a Participant's Gross Pension is different depending upon the type of retirement to which the Participant is entitled.

3.3(a) Normal Retirement in the Traditional Pension Plan—The Gross Pension of a Participant in the Traditional Pension Plan entitled to Normal Retirement is calculated as follows:

Gross Pension	=	Normal Retirement Service Percentage	X	Final Average Pay

3.3(b) Early Retirement in the Traditional Pension Plan—The Gross Pension of a Participant in the Traditional Pension Plan entitled to Early Retirement is calculated as follows:

Gross Pension	=	Normal Retirement Service Percentage	X	Final Average Pay	X	Early Retirement Adjustment Factor

3.3(c) Disability Retirement in the Traditional Pension Plan—The Gross Pension of a Participant in the Traditional Pension Plan entitled to Disability Retirement is calculated as follows:

Gross Pension	=	Normal Retirement Service Percentage	X	Final Average Pay	X	Early Retirement Adjustment Factor

Notwithstanding the foregoing calculation, the Gross Pension shall not be less than the lesser of 20% of Final Average Pay, or the Gross Pension the Participant would be entitled to if he/she worked until his/her Normal Retirement Date and had the same Final Average Pay.

3.3(d) Termination Benefits in the Traditional Pension Plan—The Gross Pension of a Participant in the Traditional Pension Plan who has a Severance From Service Date before the Participant is eligible for Normal Retirement, Early Retirement or Disability Retirement, but after accumulating at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), is equal to the Participant's Gross Pension as described in 4.1.

Except as provided in 3.3(h), such pension payments shall commence as of the Participant's Normal Retirement Date and, except as provided in 3.3(h), shall be made in monthly installments. If the Participant has, however, at least ten years of Credited Service prior to the Participant's Severance From Service Date, then such pension payments shall commence as of the first day of the month designated in writing by the Participant. The month so designated must be a month (i) no earlier than the month following the attainment of age 55, and (ii) no later than the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month. If a written designation is not received, such pension payments will commence as of the Participant's Normal Retirement Date. Such pension payments are subject to the adjustment under the early receipt provisions set forth in 3.4(c).

3.3(e) Lump Sum in PEP—The Gross Pension of a Participant in PEP who elects an immediate lump sum is calculated as follows:

Gross Pension = Total Pension Credits X Final Average Annual Pay

Notwithstanding the foregoing, the Gross Pension shall not be less than the Present Value of the Participant's Accrued Gross Pension which would have been payable as of the Participant's Normal Retirement Date based on the Participant's Final Average Pay and Credited Service as of December 31, 1999, the definition of Present Value and Accrued Gross Pension in the Plan in effect on January 1, 2000, and the other provisions of the Plan in effect on December 31, 1999. Also, the Gross Pension shall not be less than the Present Value of the deferred annuity under 3.3(g) that would be payable as of the Participant's Normal Retirement Date. If the Participant is subsequently reemployed by the Employer, the Participant shall not be given the option to repay the lump sum payment.

3.3(f) Immediate Annuity in PEP— The Gross Pension of a Participant in PEP who elects an immediate annuity is calculated as 1/12 of the following:

Gross Pension = Total Pension Credits X Final Average Annual Pay **X** Annuity Factor

Notwithstanding the foregoing, the Gross Pension of a Participant who is eligible for Early Retirement or Normal Retirement shall not be less than the Participant's Accrued Gross Pension which would have been payable as of the Benefit Commencement Date based on the Participant's Final Average Pay and Credited Service as of December 31, 1999, the definition of Accrued Gross Pension in the Plan in effect on January 1, 2000, and the other provisions of the Plan in effect on December 31, 1999.

3.3(g) Deferred Annuity in PEP—The Gross Pension of a Participant in PEP who elects a deferred annuity is calculated as 1/12 of the following:

Gross Pension	=	Total Pension Credits	X	Final Average Annual Pay	X	Deferred Annuity Factor	X	Annuity Factor

Notwithstanding the foregoing, the Gross Pension shall not be less than the Participant's Accrued Gross Pension which would have been payable as of the Benefit Commencement Date based on the Participant's Final Average Pay and Credited Service as of December 31, 1999, the definition of Accrued Gross Pension in the Plan in effect on January 1, 2000, and the other provisions of the Plan in effect on December 31, 1999.

3.3(h) Automatic Lump Sum Cash-Out—Notwithstanding anything in the Plan to the contrary, an immediate lump sum payment, in lieu of monthly payments will be made to a Participant (i) in the Traditional Pension Plan, if the Present Value of the Participant's Gross Pension, computed as of the Severance From Service Date, does not exceed $1,000, and (ii) in PEP, if the PEP Gross Pension lump sum under 3.3(e), computed as of the Severance From Service Date, does not exceed $1,000. If the Participant is subsequently reemployed by the Employer, the Participant shall not be given the option to repay the lump sum payment. No payment shall be made from the Traditional Pension Plan, if the Present Value of the Participant's Gross Pension, computed as of the Severance From Service Date, equals or exceeds $1,000, or the PEP, if the PEP Gross Pension lump sum under 3.3(e), computed as of the Severance From Service Date, equals or exceeds $1,000, absent the Participant's affirmative consent prior to the Participant's Normal Retirement Date.

3.4 Miscellaneous Gross Pension Calculation Provisions

3.4(a) Reemployment—As described in 3.2(d), monthly pension payments shall cease upon the Employer's reemployment of a Participant as an Employee, and the Participant's Gross Pension shall be recalculated and adjusted upon the Participant's subsequent termination of employment with the Employer. The Gross Pension of the Participant upon subsequent termination of employment shall be reduced by the value of monthly pension payments received prior to reemployment. The value shall be determined based on the interest rate and mortality table described in Present Value as of the Benefit Commencement Date following the subsequent termination of employment.

3.4(b) Adjustment for Part-Time Schedule—If a Traditional Pension Plan Participant worked a Part-Time Schedule at any time during the period that the Participant was accumulating Credited Service, the Participant's Average Pay described in A-9(i) shall be adjusted by multiplying such Average Pay described in A-9(i) by the following fraction:

Total of Participant's Regularly Scheduled Hours per Workweek During 35 Years of Credited Service With Highest Number of Regularly Scheduled Hours Total of All Regularly Scheduled Hours in Same Period of Credited Service Assuming Workweek of Standard Length Not in Excess of 40 Hours

If a PEP Participant worked a Part-Time Schedule at any time during the period that the Participant was accumulating Credited Service, the Participant's Gross Pension shall equal the sum of (i) the Participant's Total Pension Credits, adjusted as described below, times that portion of the Participant's Average Annual Pay described in A-8(i), and (ii) the Participant's Total Pension Credits, not adjusted as described below, times that portion of the Participant's Average Annual Pay described in A-8(ii). The Participant's Total Pension Credits shall equal the sum of the amounts attributable to each age category in the definition of Total Pension Credits times the following fraction in each age category:

> Total of Participant's Regularly Scheduled Hours per Workweek During Years of Credited Service in Each Age Category Total of All Regularly Scheduled Hours in Same Period of Credited Service Assuming Workweek of Standard Length Not in Excess of 40 Hours

For the purposes of computing the Gross Pension of a Participant who worked a Part-Time Schedule, base rate of pay shall be adjusted to reflect a 40-hour workweek.

3.4(c) Adjustment For Early Receipt in Traditional Pension Plan—If a Participant in the Traditional Pension Plan who is entitled to pension payments under 3.3(d) elects to begin receipt of his/her monthly pension payments prior to the date that the Participant attains age 65, the Participant's Gross Pension shall be reduced to offset the cost of early receipt. Such reduction shall be determined in accordance with the table included in Appendix E.

3.4(d) Adjustment For Survivor Annuity Coverage—A Participant's Gross Pension in the Traditional Pension Plan shall be reduced to offset the cost of providing (i) additional Preretirement Survivor Annuity coverage, and (ii) any Post-retirement Survivor Annuity coverage. A Participant's Gross Pension in PEP shall be reduced to offset the cost of providing any Post-retirement Survivor Benefit coverage. Post-retirement Survivor Annuity and Post-retirement Survivor Benefit coverage reductions shall be determined in accordance with the table included in Appendix F. Preretirement Survivor Annuity coverage reductions shall be determined in accordance with the table included in Appendix H.

3.4(e) Benefit and Benefit Accrual Limitations. Notwithstanding any other provision of the Plan to the contrary, the Gross Pension accrued on behalf of and provided to a Participant under the Plan shall at all times comply with applicable benefit payment and accrual limitations in accordance with Section 401(a)(29) of the Code.

3.5 Severance Plan Payments—Notwithstanding any other provision in the Plan or any Appendix to the contrary, the Gross Pension for a Participant in the PEP who receives severance payments under the Constellation Energy Group, Inc. Severance Plan shall not be less than the "minimum amount" which is the amount of the Participant's Gross Pension as of the Participant's Severance From Service Date based on (i) the Participant's Final Average Annual Pay as of the Participant's Severance From Service Date; (ii) the Participant's age projected to the Participant's Severance End Date (but not older than the greater of the Participant's actual age on the Participant's Severance From Service Date or 65); and (iii) the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, and for a Participant who (x) elects an immediate or deferred annuity, the "minimum amount" shall be computed assuming that the Annuity Factor used to convert the PEP Gross Pension lump sum to an annuity is based on the Participant's age and

Credited Service as of the Participant's Severance End Date and that the Annual Interest Rate used will be as specified by the Plan (i.e., based on the Participant's Severance From Service Date); and (y) elects a deferred annuity to commence later than the first of the month following the Participant's Severance From Service Date the "minimum amount" shall be computed assuming a Deferred Annuity Factor of 1. For purposes of computing the "minimum amount", any reduction for Survivor Annuity coverage will be based on the factors specified by the Plan using the Participant's and the spouse's or the beneficiary's age as of the Participant's Benefit Commencement Date.

Notwithstanding any other provision in the Plan or any Appendix to the contrary, the Gross Pension for a Participant in the Traditional Pension Plan who receives severance payments under the Constellation Energy Group, Inc. Severance Plan shall not be less than the "minimum amount" which is the amount of the Participant's Gross Pension as of the Participant's Severance From Service Date based on (i) the Participant's Final Average Pay as of the Participant's Severance From Service Date (ii) the Participant's age projected to the Participant's Severance End Date (but not older than the greater of the Participant's actual age on the Participant's Severance From Service Date or 65); and (iii) the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, and for a Participant who (x) is eligible for Normal Retirement based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, for purposes of computing the "minimum amount" the Participant's Benefit Commencement Date shall be assumed to be the later of the first of the month following the Participant's Severance from Service Date or the Participant's Normal Retirement Date; (y) is eligible for Early Retirement based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, for purposes of computing the "minimum amount" the Participant's Benefit Commencement Date shall be assumed to be the first of the month following the Participant's Severance End Date for purposes of determining the Early Retirement Adjustment Factor; and (z) is not eligible for Normal Retirement or Early Retirement based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, for purposes of computing the "minimum amount" the Participant's Benefit Commencement Date shall be assumed to be the earliest possible date permitted under the Plan based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date. For purposes of computing the "minimum amount", any reduction for Survivor Annuity coverage will be based on the factors specified by the Plan using the Participant's and the spouse's age as of the Participant's Benefit Commencement Date.

For purposes of calculating the "minimum amount" above, Severance End Date means the last day of the month that includes the end of the severance period under the Constellation Energy Group, Inc. Severance Plan (notwithstanding the termination of the receipt severance benefits due to the Participant's return to employment).

A Participant's "minimum amount" shall be payable on any Benefit Commencement Date allowable under the Plan without regard to this 3.5.

Except as expressly set forth above in this 3.5, this 3.5 will not affect any other provision of the Plan or the Appendix relating to the calculation of a Participant's benefit, including the Severance From Service Date, Final Average Annual Pay, Final Average Pay, the Deferred Annuity Factor, the adjustment for survivor coverage under 3.4(d), or the Annual Interest Rate.

This 3.5 is effective for Participants who commence receiving benefits under the Constellation Energy Group, Inc. Severance Plan on or after June 1, 2003.

4.1 Termination Gross Pension Calculation and Service: Traditional Pension Plan—The Gross Pension of a Participant in the Traditional Pension Plan who has a Severance From Service Date before the Participant is eligible for Normal Retirement, Early Retirement or Disability Retirement, but after accumulating at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), is calculated as follows:

Gross Pension =	Projected Gross Pension at Normal Retirement Date	X	Credited Service from Date of Hire to Calculation Date
	____________________		
	Projected Credited Service from the Date of hire to Normal Retirement Date		

In computing the "projected Gross Pension at Normal Retirement Date," it will be assumed that a Participant in the Traditional Pension Plan will continue to work for the Employer until the Participant's Normal Retirement Date, and that the Participant's Final Average Pay at such date will be equal to the Participant's Average Pay as of the calculation date. If the Participant works a Part-Time Schedule as of the calculation date, it will be assumed that the Participant will continue to work a Part-Time Schedule until the Participant's Normal Retirement Date for purposes of the computation.

4.2 Vested Right to Receive a Pension: Generally—A Participant will have a nonforfeitable right to receive a pension under the Plan if he/she has completed at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), or is an Employee on or after the later of age 65, or the date which is the fifth anniversary of the Participant's Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date).

4.3 Credited Service—Credited Service accumulated by a Participant is used in the computation of a Participant's Gross Pension. Under the Traditional Pension Plan, Participant's Credited Service is equal to the aggregate of all time periods, while classified as a Full-Time Employee, that commence with the Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date) and end with the Severance From Service Date. Under PEP, a Participant's Credited Service is equal to the number of months during which an Employee works at least one hour while classified as a Full-Time Employee. Service while an Employee of a subsidiary or affiliate of the Company that is not designated by the Board of Directors (as reflected in Appendix G) under 1.1 shall not be counted in determining Credited Service. Service while an Employee of a subsidiary or affiliate of the Company that is designated by the Board of Directors (as reflected in Appendix G) under 1.1 shall be counted in determining Credited Service only if the Employee is eligible to participate in the Plan because of such service. Credited Service shall not be given to an Employee while classified by the Employer as a leased employee described in Code Section 414(n) or a co-op, work study or summer Employee. Credited Service shall be accumulated in whole years and twelfths of a year.

Notwithstanding the foregoing, a Participant who has at least ten years of Credited Service prior to the date as of which the Participant first receives benefits under the Disability Plan, and who becomes a Disabled Participant on or after January 1, 1994, will continue to accrue Credited Service while a Disabled Participant. The pension payments made on and after August 1, 1999 on behalf of such a Participant who had a Severance From Service Date before January 1, 2000 shall be adjusted to reflect the accruing of Credited Service while a Disabled Participant. The pension payments made on and after August 1, 1999 on behalf of such a Participant who had a Severance From Service Date before January 1, 2000 shall also be adjusted so that the payments are no less than the amount the pension payments would be if the provisions of 3.3(c) had been applicable at the time of such Severance From Service Date.

4.4 Vesting Service—Vesting Service accumulated by a Participant is used in the determination of whether a Participant has a vested right to receive pension payments. A Participant's Vesting Service is determined using the elapsed time method. Under the elapsed time method, the Participant is credited with service equal to the aggregate of all time periods that commence with the Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date) and end with the Severance From Service Date.

If a Participant is reemployed within one year from his/her Severance From Service Date, the Participant shall be deemed to have been continuously employed by the Employer during such period, but only for purposes of accumulating Vesting Service. If a Participant dies while performing qualified military service (within the meaning of Section 414(u)(5) of the Code), such Participant shall be credited with Vesting Service for the period of his qualified military service.

4.5 Forfeiture and Restoration of Credited Service and Vesting Service—Once a Participant has at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), all Credited Service and Vesting Service, including all subsequently accumulated Credited Service and Vesting Service, is exempt from forfeiture. If an Employee's Severance From Service Date occurs while he/she is zero percent vested under the Plan, such Employee's Credited Service and Vesting Service accumulated prior to such Severance From Service Date shall be forfeited. All amounts so forfeited by a Participant who has a Severance From Service Date shall be deemed distributed to the Participant as of the Participant's Severance From Service Date for purposes of determining whether the Participant received a distribution of his/her entire accrued benefit under the Plan. Any forfeited Credited Service and Vesting Service shall be restored upon reemployment, if the period of time elapsed between the Severance From Service Date and the date of reemployment does not exceed five Plan Years.

Notwithstanding the foregoing, a Participant who received a lump sum payment under 3.3(e) or 3.3(h) shall not be entitled to restoration of Credited Service accumulated prior to the termination of employment that gave rise to the lump sum payment.

Notwithstanding the foregoing, for purposes of computing Credited Service and Vesting Service, the Severance From Service Date of an Employee who is absent from service beyond the first anniversary of the first day of absence by reason of a maternity or paternity absence, is the second anniversary of the first day of such absence. The period of time between the first and second anniversaries of the first day of absence from work is neither a period of service nor a period of severance.

4.6 Military Service—Notwithstanding any provision of this Plan to the contrary, benefits and service credit with respect to qualified military service will be provided in accordance with Code Section 414(u). Effective January 1, 2007, in the case of a Participant who dies while performing qualified military service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of military service) provided under the Plan had the Participant resumed and then terminated employment on account of death.

ARTICLE V—Survivor Coverage

5.1 Preretirement Survivor Annuity: Traditional Pension Plan

5.1(a) Eligibility—If a Participant in the Traditional pension Plan with a vested right to receive a pension dies before the Participant's Benefit Commencement Date (i) the Surviving Spouse or (ii) the Alternate Beneficiary (for a Participant who is not married on his/her date of death or who is married, and who has the appropriate spousal waiver and who names an Alternate Beneficiary that does not predecease the Participant) will be entitled to a Preretirement Survivor Annuity.

A Traditional Plan Participant may name more than one Alternate Beneficiary for a Preretirement Survivor Annuity. If more than one Alternate Beneficiary is named, the Participant must designate the percentage of Preretirement Survivor Annuity attributable to each recipient by delivering an Appropriate Request to the Plan Administrator.

For a Participant who is not married and who either does not name an Alternate Beneficiary or names one or more Alternate Beneficiaries and such Alternate Beneficiary (ies) predeceases the Participant, the default beneficiary for the Preretirement Survivor Annuity will be the Participant's beneficiary under the Company's employee life insurance plan

5.1(b) Value of Coverage—The Preretirement Survivor Annuity is equal to 50% of the deceased Participant's adjusted Gross Pension. The deceased Participant's Gross Pension is adjusted in accordance with the early receipt provisions set forth in 3.4(c) to the extent the Surviving Spouse's Benefit Commencement Date or the Alternate Beneficiary's Benefit Commencement Date is before the Participant's Normal Retirement Date and is permanently reduced for the cost of providing the contingent annuitant reduction factors pursuant to Appendix F.

5.1(c) Duration of Coverage—Coverage under 5.1(b) commences as of the date that the Participant has a vested right to receive a pension. With respect to a particular spouse of the Participant, coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the Participant's Benefit Commencement Date or (iv) the date on which a waiver of coverage becomes effective. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant which date is after the date the Participant named the Alternate Beneficiary and the Participant's spouse has not waived coverage, or (iv) the Participant's Benefit Commencement Date.

5.1(d) Cost of Coverage—A Participant's Gross Pension is not reduced to offset the cost of providing coverage under 5.1(b).

5.2 Preretirement Survivor Annuity: Special Rules in the Traditional Pension Plan

5.2(a) Value of Coverage—Notwithstanding 5.1(b), if a Participant in the Traditional Pension Plan dies after he/she is eligible for Early Retirement, but before the Participant's Benefit Commencement Date, the Preretirement Survivor Annuity is calculated as described in 5.1(b) except that instead of adjusting the deceased Participant's Gross Pension by the early receipt provisions set forth in 3.4(c), the Participant's Gross Pension will be multiplied by the Early Retirement Adjustment Factor, but in no event shall such factor be less than 85%.

5.2(b) Duration of Coverage—Coverage under 5.2(a) commences with the Participant is eligible for Early Retirement. With respect to a particular spouse of the Participant, coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the Participant's Benefit Commencement Date or (iv) the date on which a waiver of coverage becomes effective. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant which date is after the date the Participant named the Alternate Beneficiary and the Participant's spouse has not waived coverage, or (iv) the Participant's Benefit Commencement Date.

5.2(c) Cost of Coverage—A Participant's Gross Pension is not reduced to offset the cost of providing coverage under 5.2(a).

5.2(d) Additional Coverage—A Participant who is eligible for Early Retirement may elect additional Preretirement Survivor Annuity coverage for his/her Surviving Spouse or Alternate Beneficiary. The 50% factor in 5.1(b) may, at the election of such Participant, be increased by a multiple of 5% to a total factor not to exceed 100% and the permanent reduction to the deceased Participant's Gross Pension will be determined as set forth in 3.4(d). The additional coverage commences on the day of receipt of the Participant's election by the Plan Administrator. With respect to a particular spouse, such coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the Participant's Benefit Commencement Date, (iv) the date upon which a cancellation of additional coverage in accordance with 6.3(a) becomes effective or (v) the date on which a waiver of coverage becomes effective. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant which date is after the date the Participant named the Alternate Beneficiary and the Participant's spouse has not waived coverage, (iv) the Participant's Benefit Commencement Date or (v) the date upon which a cancellation of additional coverage in accordance with 6.3(a) becomes effective.

5.2(e) Cost of Additional Coverage—A Traditional Pension Plan Participant's Gross Pension is permanently reduced to offset the cost of providing the additional coverage under 5.2(d). Such reduction is determined as set forth in 3.4(d). The reduction in the Participant's Gross Pension to offset the cost of providing the additional Preretirement Survivor Annuity coverage will only reflect the period, if any, during which the additional coverage is effective.

5.2(f) Lump Sum Payment: Traditional Pension Plan—A Surviving Spouse or an Alternate Beneficiary entitled to a Preretirement Survivor Annuity may elect in writing to receive the Present Value of the Preretirement Survivor Annuity in a lump sum, if the following requirements are satisfied:

(i) The Participant's death occurs prior to the month before the Participant's 55th birthday; and

(ii) The Present Value of the Preretirement Survivor Annuity, computed as of the end of the month of the Participant's death, exceeds $5,000. If the Present Value of the Preretirement Survivor Annuity computed as set forth in (ii) is an amount that does not exceed $5,000, a lump sum payment for such amount will be made to the Surviving Spouse or the Alternate Beneficiary in lieu of monthly installments.

5.3 Post-retirement Survivor Annuity: Traditional Pension Plan

5.3(a) Eligibility—If a Participant in the Traditional Pension Plan who is receiving monthly pension payments under the Plan dies on or after the Participant's Benefit Commencement Date, the Surviving Spouse or the Alternate Beneficiary will be entitled to a Post-retirement Survivor Annuity unless coverage was waived. However, the Surviving Spouse or the Alternate Beneficiary of a Traditional Pension Plan Participant who received a lump sum payment is not entitled to a Post-retirement Survivor Annuity.

5.3(b) Value of Coverage—The Post-retirement Survivor Annuity is equal to 50% of the Participant's monthly pension payments.

5.3(c) Duration of Coverage—Coverage under 5.3(b) commences as of the Participant's Benefit Commencement Date. Coverage will cease upon the date of death of the Surviving Spouse or the Alternate Beneficiary.

5.3(d) Cost of Coverage—A Participant's Gross Pension is permanently reduced to offset the cost of providing coverage under 5.3(b). Such reduction is determined as set forth in 3.4(d).

5.4 Post-retirement Survivor Annuities: Special Rules for the Traditional Pension Plan

5.4(a) Additional Coverage—A Participant in the Traditional Pension Plan may elect additional Post-retirement Survivor Annuity coverage for his/her Surviving Spouse or his/her Alternate Beneficiary. The 50% factor in 5.3(b) may, at the election of such Participant, be increased by a multiple of 5% to a total factor not to exceed 100%. The additional coverage commences as of the Participant's Benefit Commencement Date. Such coverage will cease as set forth in 5.3(c).

5.4(b) Cost of Additional Coverage—A Participant's Gross Pension is permanently reduced to offset the cost of providing the additional coverage under 5.4(a). Such reduction is determined as set forth in 3.4(d).

5.5 Form of Survivor Annuity Payments: Traditional Pension Plan—Except as provided in 5.2(f), all Survivor Annuity payments under the Traditional Pension Plan are paid in monthly installments.

5.6 Timing of Survivor Annuity Payments: Traditional Pension Plan

5.6(a) Commencement of Preretirement Survivor Annuity Payments – Preretirement Survivor Annuity payments in the Traditional Pension Plan shall commence as of the first day of the month designated by the Surviving Spouse in writing. The date designated may be no earlier than the later of (i) the first day of the month following the month of the Participant's death or (ii) the first day of the month following the date the deceased Participant would have attained age 55, and may be no later than the later of (i) the Participant's Normal Retirement Date, or (ii) the first day of the month following the month of the Participant's death. The Preretirement Survivor Annuity payments in the Traditional Pension Plan to an Alternate Beneficiary shall be made as of the first day of the month following the Participant's death.

5.6(b) Cessation of Survivor Annuity Payments —Survivor Annuity payments shall permanently cease upon the death of the Surviving Spouse or the Alternate Beneficiary, effective with the Survivor Annuity payment for the month following the month of the Surviving Spouse's or the Alternate Beneficiary's death.

5.7 Change in Survivor Annuity Recipient: Traditional Pension Plan —If subsequent to the date of the commencement of (i) pension payments that were reduced to offset the cost of providing Post-retirement Survivor Annuity coverage or (ii) Preretirement Survivor Annuity payments, a person (other than the individual taken into account in determining the amount of such payments) asserts a right to a Survivor Annuity, no Survivor Annuity payments will be made to such person until the Plan has been repaid the cumulative additional reduction, if any, in pension payments that should have been made to offset the cost of providing Survivor Annuity coverage or payments for such person.

5.8 Preretirement Survivor Benefit: PEP

5.8(a) Eligibility—If a Participant in PEP with a vested right to receive a pension dies before the Participant's Benefit Commencement Date (i) the Surviving Spouse or (ii) the Alternate Beneficiary (for a Participant who is not married on his/her date of death or who is married, and who has the appropriate spousal waiver and who names an Alternate Beneficiary that does not predecease the Participant) will be entitled to a Preretirement Survivor Benefit.

A PEP Participant may name more than one Alternate Beneficiary for a Preretirement Survivor Benefit. If more than one Alternate Beneficiary is named, the Participant must designate the percentage of Preretirement Survivor Benefit attributable to each recipient by delivering an Appropriate Request to the Plan Administrator.

For a Participant who is not married and who either does not name an Alternate Beneficiary or names one or more Alternate Beneficiaries and such Alternate Beneficiary(ies) predeceases the Participant, the default beneficiary for the Preretirement Survivor Benefit will be the Participant's beneficiary under the Company's employee life insurance plan.

5.8(b) Value of Coverage—The Preretirement Survivor Benefit is equal to 100% of the deceased Participant's Gross Pension. If a married PEP Participant dies and does not have a spousal waiver, the Surviving Spouse will receive a deferred annuity described in 3.3(g), unless the Surviving Spouse elects within 60 days of the Participant's date of death to receive a lump sum described in 3.3(e) or an immediate annuity described in 3.3(f). The deferred annuity will begin as of the first day of the month designated in writing by the Surviving Spouse, which is after the date the Participant would have attained age 55 and not later than the Participant's Normal Retirement Date. The immediate or deferred annuity will be calculated based on the Surviving Spouse's age as of the date the annuity begins. If a PEP Participant who is not married or who is married and has a spousal waiver dies, the Alternate Beneficiary will receive a lump sum described in 3.3(e).

5.8(c) Duration of Coverage—Coverage under 5.8(b) commences as of the date that the Participant has a vested right to receive a pension.

With respect to a particular spouse of the Participant, coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the date on which a waiver of coverage becomes effective, or (iv) the Participant's Benefit Commencement Date. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant and his/her spouse, which date is after the date the Participant named the Alternate Beneficiary, or (iv) the Participant's Benefit Commencement Date.

5.8(d) Cost of Coverage—A Participant's PEP payments are not reduced to offset the cost of providing coverage under 5.8.

5.9 Post-retirement Survivor Benefit: PEP

5.9(a) Eligibility—If a Participant in PEP who is receiving monthly pension payments under the Plan dies on or after the Participant's Benefit Commencement Date, (i) the Surviving Spouse will be entitled to a Post-retirement Survivor Benefit unless it is waived or (ii) any named Alternate Beneficiary (for a Participant who is not married, or who is married and who has the appropriate spousal waiver and who names an Alternate Beneficiary) will be entitled to a Post-retirement Survivor Benefit.

A PEP Participant may name only one Alternate Beneficiary for the Post-retirement Survivor Benefit. Only an individual may be named as an Alternate Beneficiary. If the Participant received a lump sum payment, then no Post-retirement Survivor Benefit is available.

5.9(b) Value of Coverage—The Post-retirement Survivor Benefit is equal to 50% of the Participant's monthly pension payments.

5.9(c) Duration of Coverage—Coverage under 5.9(b) commences as of the Participant's Benefit Commencement Date. Coverage will cease upon the date of death of the Surviving Spouse or the date of death of the Alternate Beneficiary, whichever is applicable.

5.9(d) Cost of Coverage—A Participant's Gross Pension is permanently reduced to offset the cost of providing coverage under 5.9(b). Such reduction is determined as set forth in 3.4(d).

5.10 Post-retirement Survivor Benefit: Special Rules for PEP

5.10(a) Additional Coverage—A Participant in PEP may elect additional Post-retirement Survivor Benefit coverage for his/her Surviving Spouse or Alternate Beneficiary. The 50% factor in 5.9(b) may, at the election of such Participant, be increased by a multiple of 5% to a total factor not to exceed 100%. The additional coverage commences as of the Participant's Benefit Commencement Date. Such coverage will cease as set forth in 5.9(c).

5.10(b) Cost of Additional Coverage—A Participant's Gross Pension is permanently reduced to offset the cost of providing the additional coverage under 5.10(a). Such reduction is determined as set forth in 3.4(d).

5.11 Form of Survivor Benefit Payments: PEP—Except as provided in 5.12, Preretirement Survivor Benefit payments under PEP are payable in the form described in 5.8(b). Post-retirement Survivor Benefits under PEP are paid in monthly installments.

5.12 Automatic Cash-Out: PEP—If a Participant in PEP dies before his/her Benefit Commencement Date and the PEP Gross Pension lump sum amount described in 3.3(e) computed as of the end of the month of the Participant's death does not exceed $5,000, then the Preretirement Survivor Benefit will be paid in a lump sum.

5.13 Timing of Survivor Benefit Payments: PEP

5.13(a) Commencement of Preretirement Survivor Benefit Payments —Preretirement Survivor Benefit payments to a Surviving Spouse shall commence as of the first day of the month designated in writing by the Surviving Spouse. The date so designated must be later than the month of the Participant's death but not later than the later of (i) the Participant's Normal Retirement Date, or (ii) the first day of the month following the month of the Participant's death. The Preretirement Survivor Annuity payment in PEP to an Alternate Beneficiary shall be made as of the first day of the month following the Participant's death.

5.13(b) Cessation of Survivor Benefit Payments—Preretirement Survivor Benefit payments and Post-retirement Survivor Benefit payments shall permanently cease upon the death of the Surviving Spouse or Alternate Beneficiary, effective with the Survivor Benefit payment for the month following the month of the Surviving Spouse's or Alternate Beneficiary's death.

5.14 Election Period Survivor Benefits—If an active Participant dies during the election period referenced in 1.2, then regardless of any election that the Participant may have already made, the Participant's Surviving Spouse will have the option of electing the Preretirement Survivor Annuity under the Traditional Pension Plan or the Preretirement Survivor Benefit under PEP. The Surviving Spouse must make his/her choice by the later of (i) 60 days after the date the Plan Administrator notifies the Surviving Spouse of the option, or (ii) June 30, 2000. If an active Participant dies during the election period referenced in 1.2 and is not married, then the Alternate Beneficiary will receive the Preretirement Survivor Benefit under PEP. For the purposes of this 5.14, if the Participant is not married and did not name an Alternate Beneficiary then the default beneficiary will be the Participant's beneficiary under the Company's employee life insurance plan. If no beneficiary under the life insurance plan exists, then the default beneficiary will be the Participant's estate.

ARTICLE VI—Procedures; Administration; Claims

6.1 Procedures: Commencement of Payments Under the Plan —Any payment required to be made under the Plan may, at the discretion of the Plan Administrator, be suspended until the name and address of the recipient and all information necessary to determine the amount payable (including, when applicable, but not limited to, the recipient's age, proof of marital status and, if married, an Appropriate Request that includes the name, birth date and current address of the Participant's spouse and which either rejects the 50% Post-retirement Survivor Annuity or Post-retirement Survivor Benefit or accepts such coverage and requests or declines additional coverage) has been received by the Plan Administrator. Generally the Appropriate Request must be executed by the Participant and spouse (or their guardian, attorney-in-fact, or other legal representative), under oath, before a notary public. The signature of a legal representative must be supported by a copy of the instrument effecting the appointment. However, for the purpose of the 50% spousal election for Post-retirement Survivor Annuity or Post-retirement Survivor Benefit, the Appropriate Request does not need to be notarized. Payments that were suspended will be made in a lump sum, without interest, as soon as possible after the Plan Administrator receives such information. The Plan Administrator may, in his/her sole discretion, require assurances in the form of an indemnity agreement or bond, prior to the commencement of any payments, if the accuracy of certain information has not been in his/her opinion conclusively established. To the extent payments have not been claimed during a three year period, all payments will be forfeited. However, if the recipient subsequently files a proper claim with the Plan Administrator for such amounts, and the claim is filed prior to the termination of the Plan, payments that were suspended will be made in a lump sum, without interest, as soon as possible after the Plan Administrator receives such claim.

6.1(a) Proof of Marital Status—The Plan Administrator may rely on a notarized written declaration made on an Appropriate Request that a Participant is presently unmarried unless (i) the Participant's spouse is currently a designated beneficiary under any Employer-sponsored life insurance, or (ii) the Participant's spouse is currently a dependent under any Employer-sponsored group health insurance. If (i) or (ii) above indicate that a spouse exists, the resulting presumption will be overcome if the notarized written declaration is supported by a copy of a death certificate or final decree of divorce or annulment which, in the Plan Administrator's sole discretion, appears to have been properly issued. If an allegedly estranged spouse can't be reached by certified mail, return receipt requested, at the last known address of the spouse, the Plan Administrator, in his/her sole discretion, may accept the Appropriate Request without the signature of the spouse (or the spouse's legal representative).

6.2 Procedures: Written Explanation of Survivor Annuity Coverage—

6.2(a) Additional Preretirement Survivor Annuity Coverage—Within one year of the date the Participant in the Traditional Pension Plan becomes eligible for additional Preretirement Survivor Annuity coverage, the Plan Administrator shall furnish to the Participant a written explanation of (i) the terms and conditions of the additional Preretirement Survivor Annuity coverage, and (ii) the Participant's right to elect or change or cancel an election of the additional Preretirement Survivor Annuity coverage.

6.2(b) Preretirement Survivor Benefit—The Plan Administrator shall furnish to the Participant in PEP a written explanation of (i) the terms and conditions of the Preretirement Survivor Benefit, (ii) the Participant's right to designate the beneficiary of the Preretirement Survivor Benefit, (iii) the rights of the Participant's spouse, and (iv) the right to change or revoke a beneficiary designation. The written explanation shall be provided to the Participant (A) as soon as practicable after the Participant begins to participate in PEP, (B) between January 1 of the year the Participant attains age 32 and December 31 of the year the Participant attains age 34, unless the date in (A) is subsequent to January 1 of the year the Participant attains age 32, (C) within one year after the Participant's Severance From Service Date provided that (a) the Participant's Severance From Service Date occurs before the Participant attains age 35, (b) the Participant is vested at his/her Severance From Service Date, (c) the Participant does not have a Benefit Commencement Date before the written explanation is provided, and (d) the written explanation was not otherwise provided within one year before the Participant's Severance From Service Date, and (D) as soon as practicable after the Participant is rehired.

6.2 (c) Post-retirement Survivor Annuity or Post-retirement Survivor Benefit —(i) The Plan Administrator shall furnish to the Participant a written explanation of (A) the terms and conditions of the Post-retirement Survivor Annuity or Post-retirement Survivor Benefit, (B) the Participant's right to make and the effect of an election to waive the Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit, (C) the rights of the Participant's spouse, and (D) the right to make, and the effect of, a withdrawal of a previous election to waive the Post-retirement Survivor Annuity or Post-retirement Survivor Benefit.

(ii) The written explanation shall be provided to the Participant no more than 180 and no less than 30 days before the Participant's Benefit Commencement Date, subject to the following exception:

(A) The written explanation may be provided less than 30 days before the Benefit Commencement Date provided that the Participant is given a specified period of at least 30 days to make the election (and that other Plan requirements are satisfied); and

(B) A Participant may affirmatively elect, with the Participant's Spouse's consent, to waive the minimum 30-day election period. The waiver of the minimum 30-day period will be effective only if:

(I) the Participant and the Participant's Spouse have been clearly informed of the right to have a minimum 30-day election period to consider whether to waive the Post-retirement Survivor Annuity or Post-retirement Survivor Benefit;

(II) the distribution begins at least 7 days after the date that the written explanation is provided; and

(III) the Participant is permitted to revoke an election, and the Spouse is permitted to revoke a consent, until the later of the Benefit Commencement Date or the expiration of the 7-day period that begins the day after the written explanation is provided.

6.3 Procedures: Election of Survivor Annuity Coverage —

6.3(a) Additional Preretirement Survivor Annuity Coverage —As described in 5.2(d), a Participant in the Traditional Pension Plan may elect to change or cancel an election of the additional Preretirement Survivor Annuity coverage on an Appropriate Request at any time between the date the Participant becomes eligible for the additional Preretirement Survivor Annuity coverage and the Participant's Benefit Commencement Date. Such election, change or cancellation shall not require the consent of the Participant's spouse.

6.3(b) Preretirement Survivor Benefit—A Participant in PEP may select his/her spouse, an individual or a trust to be his/her beneficiary of the Preretirement Survivor Benefit, and may change his/her selection, on an Appropriate Request, at any time before his/her Benefit Commencement Date. If the Participant selects a beneficiary other than his/her spouse, the selection shall be effective only if the Participant is not married on his/her date of death or the individual who is the spouse of the Participant on the Participant's date of death has consented to the selection in writing and such consent was witnessed by a notary public. Notwithstanding the preceding sentence, if the Participant selects a beneficiary other than the Participant's spouse and the Participant's spouse consents to such election prior to January 1 of the year the Participant attains age 35, the designation and waiver shall become ineffective on such January 1, unless the Participant does not have a surviving spouse on the Participant's date of death.

6.3(c) Post-retirement Survivor Annuity or Post-retirement Survivor Benefit —After the Plan Administrator provides the Participant with the written explanation in 6.2(c)(i) during the period in 6.2(c)(ii), a Participant in the Traditional Pension Plan may waive the Post-retirement Survivor Annuity or may elect additional Post-retirement Survivor Annuity coverage by an Appropriate Request. A Participant in the Traditional Pension Plan may revoke such waiver or election and make a new election until the

Participant's Benefit Commencement Date (or, if later, the expiration of the 7-day period that begins after the written explanation is provided), without limit on the number of changes that may be made. After the Plan Administrator provides the Participant with the written explanation in 6.2(c)(i) during the period in 6.2(c)(ii), a Participant in PEP may waive the Post-retirement Survivor Benefit with the Participant's spouse as beneficiary or may elect additional Post-retirement Survivor Benefit coverage with the Participant's spouse as beneficiary, or may select a beneficiary other than the Participant's spouse by an Appropriate Request. A Participant in PEP may revoke such waiver or election and make a new election until the latest of the Participant's Benefit Commencement Date, the expiration of the 7-day period that begins after the written explanation is provided), and 60 days after the Participant's Severance From Service Date (but not later than the date of distribution) without limit on the number of changes that may be made. If the Participant waives the Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit with his/her spouse as beneficiary or selects a beneficiary other than his/her spouse for the Post-retirement Survivor Benefit, the waiver or selection shall be effective only if the Participant is not married on his/her Benefit Commencement Date or the Participant's spouse on the Participant's Benefit Commencement Date has consented to the waiver or selection in writing and such consent was witnessed by a notary public.

6.4 Plan Administration: The Administrative Committee

6.4(a) Generally—The Administrative Committee shall consist of members of senior management of the Company appointed from time to time by the Chief Executive Officer of the Company. The Chairman of the Committee shall be the Chief Human Resources Officer of the Company. A member of the Committee may resign by delivering his/her written resignation to the Chairman of the Committee. A written resignation shall become effective as of the date specified therein. No member of the Committee shall receive compensation from the Plan for his/her services as a member.

6.4(b) The Administrative Committee: Authority and Duties —The Administrative Committee has the authority to adjudicate claims appeals as set forth in Section 6.8, and to delegate, in writing, any part of its authority and duties to one or more designees.

6.5 Plan Administration: The Investment Committee

6.5(a) Generally—The Investment Committee shall consist of members of senior management of the Company appointed from time to time by the Chief Executive Officer of the Company. The Chairman of the Committee shall be the Chief Financial Officer of the Company. A member of the Committee may resign by delivering his/her written resignation to the Chairman of the Committee. A written resignation shall become effective as of the date specified therein. No member of the Committee shall receive compensation from the Plan for his/her services as a member.

6.5(b) Authority and Duties—The Investment Committee has the authority and responsibility, subject to the review and modification of the Board of Directors:

(i) to develop and implement strategies for the custody and management of Plan assets in accordance with its investment policy statement,

(ii) to engage in negotiations related to the custody or management of Plan assets,

(iii) to exercise all rights reserved to the Company as party to a contract or trust instrument related to the custody or management of its assets,

(iv) to delegate, in writing, any part of its authority and duties to one or more designees, and

(v) to report annually to the Board of Directors.

6.6 Plan Administration: The Plan Administrator

6.6(a) Generally—The Plan will be administered by the Director – Benefits of the Company (or the successor to that function) as Plan Administrator, under the direct supervision of the Chief Human Resources Officer of the Company (or under the supervision of the officer succeeding to that function).

6.6(b) Authority and Duties—The Plan Administrator will establish policies and procedures necessary to efficiently operate the Plan. The Plan Administrator is responsible for the day to day operation of the Plan. The Plan Administrator will:

(i) furnish when due all required information and reports to Participants and regulatory agencies, and

(ii) receive all communications from Participants and regulatory agencies about the Plan and take appropriate action in response thereto. The Plan Administrator may, in writing, delegate any part of his/her authority and duties to one or more designees. The designee or the Plan Administrator may withdraw the designation in writing.

6.7 Plan Administration: Indemnification—The Plan Administrator (and his/her designees), the Board of Directors, Chairman of the Board of Directors, Vice Chairman of the Board of Directors, Administrative Committee and Investment Committee members, the –Chief Human Resources Officer (or the officer succeeding to that function) of the Company and all employees of the Employer whose duties involve Plan matters, shall be indemnified by the Company, or from the proceeds under insurance policies purchased by the Company, against any and all liabilities arising by reason of any act or failure to act made in good faith pursuant to the provisions of the Plan, including expenses reasonably incurred in the defense of any claim relating thereto.

6.8 Plan Administration: Claims

6.8(a) Denial of Claim—If after a Participant makes a written claim for benefits, such claim is denied in full or in part, the Plan Administrator shall, within 90 days after receipt of the claim, provide the Participant (at the Participant's last address appearing on the records of the Plan) with written notice by mail, in language calculated to be understood by the Participant, of the denial of the claim stating (i) the specific reasons for the denial, (ii) the specific references to pertinent Plan provisions on which the denial is based, (iii) any additional material or information necessary for the Participant to resubmit the claim, including an explanation of why such material or information is necessary, and (iv) an explanation of the claims appeal procedure. If special circumstances require an extension of time to process the claim, within 90 days after receipt of the claim, the Plan Administrator shall provide the Participant with written notice by mail specifying the reasons for the need for an extension of time, and a date by which he/she expects to render a decision. In that event, the initial 90 day period for notice of denial shall be extended by an additional 90 days.

6.8(b) Appeal of Claim—If a Participant's written claim has been denied or if the Participant has not received written notice of denial within the period prescribed by 6.8(a), he/she may file an appeal with the –Administrative Committee. The Participant or his/her duly authorized representative may request to review pertinent documents. The appeal must be submitted in writing within 60 days of the date the Participant receives or should have received notice of the denial. The appeal may be made by the Participant or his/her duly authorized representative. The appeal must state the reasons for the appeal and shall be accompanied by any evidence or documentation to support the Participant's position. The –Administrative Committee shall review the Participant's appeal promptly and shall advise the Participant of his/her decision in writing, in language calculated to be understood by the Participant, stating the specific reasons for his/her decision withspecific reference to pertinent Plan provisions on which the decision is based. This written decision shall be sent to the Participant (at his/her last address appearing on the records of the Plan) by mail no later than 60 days after receipt of the written appeal, unless special circumstances require an extension of time for processing the appeal, obtaining more information or conducting an investigation of the facts. In no event shall the written decision be sent to the Participant later than 120 days after receipt by the –Administrative Committee of the written appeal. The determination of the –Administrative Committee shall be final and binding on all parties and not subject to further appeal.

6.8(c) Exclusive Method—The procedure for review of claims outlined in this 6.8 is the exclusive method available for resolving claims under the Plan, notwithstanding the existence of other Employer procedures applicable to Employee grievances in other areas. No Participant or beneficiary is entitled to bring any action, whether at law or in equity against any Employer or their respective agents, officers, directors or employees, including the Administrative Committee, the Investment Committee, the Plan Administrator, his/her designees, or the –Chief Human Resources Officer of the Company (or any officer succeeding to that function) in connection with any right, privilege or benefit provided under this Plan unless and until, as a condition precedent, all the remedies provided under this Section 6.8 have been exhausted.

6.9 Direct Rollover of Eligible Rollover Distributions—This 6.9 applies to distributions made on or after January 1, 1993, or such other effective date as specified herein. Notwithstanding any provision of the Plan to the contrary that would otherwise limit a distributee's election under this 6.9; a distributee may elect, at the time and in the manner prescribed by the Plan Administrator, to have any portion of an eligible rollover distribution paid directly to an eligible retirement plan specified by the distributee in a direct rollover.

For purposes of this 6.9, eligible rollover distribution means any distribution of all or any portion of the balance to the credit of the distributee, except that an eligible rollover distribution does not include: any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for the life (or life expectancy) of the distributee or the joint lives (or joint life expectancies) of the distributee and the distributee's designated beneficiary, or for a specified period of ten years or more; any distribution to the extent such distribution is required under Code Section 401(a)(9); and the portion of any distribution that is not includible in gross income (determined without regard to the exclusion for net unrealized appreciation with respect to employer securities).

For purposes of this 6.9, eligible retirement plan means an individual retirement account described in Code Section 408(a), a Roth individual retirement account described in Code Section 408A(b) (subject to current Roth individual retirement account conversion rules), an individual retirement annuity described in Code Section 408(b), an individual retirement annuity described in Code Section 403(a), or a qualified trust described in Code Section 401(a), that accepts the distributee's eligible rollover distribution. Eligible retirement plan shall also mean an eligible deferred compensation plan described in Code Section 457(b) that is maintained by a state, political subdivision of a state, or an agency or instrumentality of a state or an entity exempt from federal income tax, or an annuity contract described in Code section 403(b).

For purposes of this 6.9, a distributee means an Employee or Former Employee. In addition, a Surviving Spouse (or, effective for distributions made after December 31, 2009, a non-spouse beneficiary as described in Code Section 402(c)(11)) and the Employee's or Former Employee's spouse or former spouse who is the alternate payee under a qualified domestic relations order, as defined in Code Section 414(p), are distributees with regard to the interest of the spouse or former spouse.

For purposes of this 6.9, a direct rollover is a payment by the Plan to the eligible retirement plan specified by the distributee.

ARTICLE VII—Plan Funding

7.1 Contributions—No contributions from any Participant shall be required or permitted under the Plan. The Employer shall make contributions in such amounts and at such times as determined by the Investment Committee in accordance with a funding method and policy to be established by the Investment Committee. Forfeitures arising under this Plan shall be applied to reduce the expenses of Plan administration, not to increase the benefits otherwise payable to Participants.

7.2 Payments to the Trustee—All contributions made by the Employer under this Plan shall be paid to the Trustee and shall become assets of the Trust.

ARTICLE VIII—Miscellaneous Provisions

8.1 Inalienability of Benefits: Generally—No benefit or interest available under the Plan will be subject to assignment, attachment, alienation, or other legal process, either voluntarily or involuntarily. Except as provided in 8.1(a), the preceding sentence will also apply to the creation, assignment or recognition of a right to any benefit payable with respect to a Participant pursuant to a domestic relations order. Except as provided in 8.1(b) and 8.7, payments required under the Plan will be made to and in the name of the person entitled to such payments under the terms of the Plan, or to and in the name of such person's authorized representative. Payments to any financial institution to the credit of such person will constitute payments to and in the name of the person entitled to such payments under the terms of the Plan.

8.1(a) Qualified Domestic Relations Orders—The anti-alienation provisions of 8.1 do not apply to qualified domestic relations orders, as the term is defined in Code Section 414(p). The Plan Administrator has established and will maintain written procedures to determine the qualified status of domestic relations orders and to administer distributions under such qualified orders. To the extent provided under a qualified domestic relations order, a former spouse of a Participant shall be treated as the spouse or Surviving Spouse for all purposes under the Plan.

A qualified domestic relations order will not require the Plan to provide any type or form of benefit, or any option, not otherwise provided under the Plan.

Notwithstanding the preceding paragraph, if provided under a qualified domestic relations order, an alternate payee as described in Code Section 414(p) may receive his/her entire interest under the order as a lump sum payment as soon as administratively possible after a domestic relation order is qualified by the Plan Administrator. Such lump sum payment will be limited to (i) in the case of a Participant in the Traditional Pension Plan, the Present Value of the Participant's Gross Pension under 3.3(a), calculated as of the date as of which the lump sum is paid, and (ii) in the case of a Participant in PEP, the PEP Gross Pension lump sum under 3.3(e), calculated as of the date as of which the lump sum is paid. Unless unambiguously stated otherwise in the qualified domestic relations order, such lump sum will equal a percentage or portion (as specified in the order) of the amount described in (i) or (ii) above.

A Participant's Gross Pension (payable at the time and in the form such Gross Pension is actually paid to the Participant or, if the Participant dies before his/her Benefit Commencement Date, payable at the time and in the form the Preretirement Survivor Annuity or Preretirement Survivor Benefit is actually paid to the Surviving Spouse or Alternate Beneficiary) will be reduced by the benefits provided to an alternate payee described in Code Section 414(p)(8) under a qualified domestic relations order. Such Gross Pension will be reduced as follows:

(i) If the alternate payee receives a lump sum payment, the Gross Pension will be reduced by accumulating such lump sum payment with the Annual Interest Rate from the date as of which the lump sum is paid to the Participant's (or the Surviving Spouse's or Alternate Beneficiary's) Benefit Commencement Date, and converting such accumulated amount to the form of payment paid to the Participant (or Surviving Spouse or Alternate Beneficiary) using the Annual Interest Rate and the mortality table described in Code Section 417(e)(3). The Annual Interest Rate in the preceding sentence will be (1) on and after January 1, 2008, the rate of interest specified under Code Section 417(e) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67 and (2) prior to January 1, 2008, the annual rate of interest on 30-year Treasury securities, in each case for the November of the Plan Year immediately preceding the Plan Year in which the lump sum payment is made to the alternate payee. For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2001-62 and for distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2007-67.

(ii) If the alternate payee receives monthly annuity payments and the Participant also receives monthly annuity payments, the alternate payee's monthly annuity payments have a Benefit Commencement Date that is on or after the Participant's Benefit Commencement Date, the alternate payee's monthly annuity payments are payable until a date that is no later than the Participant's date of death, and the alternate payee's monthly annuity payments are no greater than the monthly payment the Participant would receive if the qualified domestic relations order did not exist, the Participant's monthly annuity payments will be reduced by the dollar amount of the monthly annuity payments provided to the alternate payee.

(iii) If the alternate payee receives monthly annuity payments and the conditions in (ii) are not satisfied, the Gross Pension will be reduced by accumulating the Present Value of the alternate payee's monthly annuity payments (with such Present Value being determined as of the date such annuity payments begin to be paid to the alternate payee) with the Annual Interest Rate from the date as of which such Present Value is determined to the Participant's (or Surviving Spouse's or Alternate Beneficiary's) Benefit Commencement Date, and converting such accumulated amount to the form of payment paid to the Participant (or Surviving Spouse or Alternate Beneficiary) using the Annual Interest Rate and the mortality table described in Code Section 417(e)(3). The Annual Interest Rate in the preceding sentence will be (1) on and after January 1, 2008, the rate of interest specified under Code Section 417(e)(3) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67 and (2) prior to January 1, 2008, the annual rate of interest on 30-year Treasury securities, in each case, for the November of the Plan Year immediately preceding the Plan Year in which the Present Value is determined. For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2001-62 and for distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2007-67.

8.1(b) Miscellaneous Exceptions—The anti-alienation provisions of 8.1 do not apply to certain voluntary and revocable assignments or alienations or other arrangements permitted under the Code and ERISA, including under Code Section 401(a)(13) and the applicable Treasury regulations.

8.2 Exclusive Benefit: Generally—Except as provided in 8.2(a), all contributions made by any Employer to any insurance company or Trustee for the purpose of funding the Plan are irrevocable and shall not revert to the Employer. Prior to the satisfaction of all liabilities under the Plan, such contributions, as well as the corpus and income of the Trust, shall not be diverted to or used for purposes other than the exclusive benefit of Participants and their beneficiaries and defraying reasonable expenses of Plan administration, including expenses of service providers who support plan administrative or fiduciary functions.

8.2(a) Exceptions—Any contribution made by an Employer by mistake of fact shall be returned to the Employer provided the return is made within one year after the payment of such contribution to the insurance company or Trustee, and provided further that earnings attributable to the excess contribution may not be returned to the Employer, but losses attributable to the excess contribution must reduce the amount returned.

Any contribution made by an Employer shall be returned to the Employer to the extent the deduction of such contribution is disallowed under Code Section 404, provided the return is made within one year after the disallowance of the deduction by the Internal Revenue Service. For purposes of this provision, all contributions made by an Employer to the Plan are expressly conditioned upon their deductibility under Code Section 404, and any nondeductible contributions must be returned to the Employer.

Any excess assets shall be returned to the Employer upon the Plan’s termination, but only after satisfaction of all Plan liabilities to Participants and their beneficiaries.

8.3 No Right to Employment—Nothing contained in the Plan shall be construed as a contract of employment between an Employer and any Employee, or as a right of any Employee to continue in the employment of an Employer or as a limitation of the right of an Employer to discharge an Employee with or without cause.

8.4 Controlling Law—The Plan and its administration shall be governed by the laws of the State of Maryland except to the extent preempted by Federal law.

8.5 Number—Words used in the singular are intended to include the plural, whenever appropriate.

8.6 Titles and Headings—Titles of Articles and headings to Sections in the Plan are placed herein solely for convenience of reference and, in any case of conflict, the text of the Plan, rather than such titles and headings, shall control.

8.7 Payment of Benefits to Incompetents—If the Plan Administrator determines that any participant, spouse or beneficiary is unable to care for his affairs because of minority, illness, infirmity, accident or any other reason, any distributions due may be made at the direction of the Plan Administrator to the guardian, conservator, legal representative, spouse, child, parent or other blood relative or to any person deemed by the Plan Administrator to have incurred expenses for such participant, spouse, or beneficiary entitled to distributions under the Plan. Such distribution shall, to the extent thereof, be a complete discharge of all liabilities of the Plan, the Employer, the Plan Administrator, the Trustee and the Trust.

ARTICLE IX—Amendment, Termination, Mergers or Consolidations

9.1 Amendment—In the event of the amendment of the Plan as permitted under Article VI, such amendment shall not cause the elimination or reduction of any Plan benefit as prohibited under the provisions of Code Section 411(d)(6).

Unless an amendment or Plan provision specifically provides otherwise, no Plan amendment will have a retroactive or prospective effect on the rights of former Employees whose active employment with the Employer terminated prior to the effective date of the amendment.

9.1(a) Amendment Authority of the Board of Directors —The Board of Directors reserves the right, at their exclusive discretion:

(i) to discontinue or terminate, merge or consolidate the Plan, in whole or in part,

(ii) to determine whether, and to what extent, employees of subsidiaries of the Company will be eligible to participate in the Plan,

(iii) to amend the Plan, in whole or in part, on advice of counsel, and except as otherwise provided herein, the Board of Directors may delegate the right to amend the Plan with respect to certain matters, and

(iv) to delegate to special committees or subcommittees the power to exercise the rights otherwise reserved to the Board of Directors in this Section 9.1(a).

9.1(b) Amendment Authority of the Chairman of the Board of Directors —The Chairman of the Board of Directors has the right, subject to the review and modification of the Board of Directors:

(i) to amend the Plan, from time to time, as shall be necessary or advisable in the interpretation, administration or operation thereof or as required by law, on the advice of counsel.

(ii) to exercise all rights and authority related to the operation of the Plan that are not expressly reserved to the Board of Directors or otherwise delegated by the Board of Directors,

(iii) to appoint the members of the Investment and Administrative Committees, as set forth in Sections 6.4 and 6.5, and

(iii) to delegate, in writing, any part of his/her authority to one or more designees.

9.1(c) Amendment Authority of the Executive Group —Effective July 23, 2010 the Executve Group may approve amendments to the Plan that have less than a $10 million impact on the Plan's accumulated benefit obligation per amendment.

9.1(d) Amendment Authority of the Chief Human Resources Officer —The Chief Human Resources Officer may make any amendment to the Plan that does not increase the annual liabilities of the Plan materially, or as required by law, upon the advice of counsel.

9.1(e) Amendment Authority of the Plan Administrator —The Plan Administrator may make any amendment to the Plan as required by law, upon the advice of counsel.

9.1(f) Report to the Board—At least annually, the Company's Chief Executive Officer shall report all amendments made pursuant to the authorities set forth in Sections 9.1(b) and (c) to the Board of Directors.

9.2 Termination—In the event of the termination or partial termination of the Plan, the rights of all affected Participants entitled to benefits accrued to the date of such termination or partial termination (to the extent funded as of such date) shall be nonforfeitable. A Participant whose benefits were forfeited, in accordance with 4.5, prior to the date of termination or partial termination, shall not be entitled to nonforfeitable benefits as a result of the preceding sentence. In the event of the termination of the Plan, the benefit of any highly compensated employee (and any former highly compensated employee) as those terms are defined in Code Section 414(q) and the related regulations, is limited to a benefit that is nondiscriminatory under Code Section 401(a)(4).

9.3 Merger or Consolidation—In the event of a merger or consolidation of the Plan with, or transfer of assets and liabilities of the Plan to, any other plan, each Participant will receive a benefit immediately after such merger, consolidation, or transfer (computed as if the Plan had then terminated) which is equal to or greater than the benefit the Participant was entitled to immediately before such merger, consolidation, or transfer (computed as if the Plan had then terminated) to the extent required under Section 414(*l*) of the Code.

9.4 Spin Offs To and From the CENG Plan—This 9.4 is effective as of the CENG Effective Date. In any case where assets and liabilities are spun off from or to this Plan, each Participant (whether or not vested) will be entitled to an accrued benefit immediately after such spin off or transfer (computed as if this Plan or the transferee plan, as applicable, had then terminated) that satisfies the requirements of 9.3; provided that such accrued benefit will be payable from the applicable plan if and only if all applicable requirements for payment under the applicable plan are satisfied including, without limitation, applicable vesting requirements. Under no circumstances shall any individual be entitled to duplicate benefits under this Plan and the CENG Plan (or any other qualified defined benefit pension plan sponsored by the Company, CENG or any of their subsidiaries or affiliates).

9.4(a) Introduction—Effective as of the CENG Effective Date, ÉLECTRICITÉ DE FRANCE INTERNATIONAL, SA and its affiliates acquired 49.99 of the membership interests of CENG from the Company; CENG and certain of its affiliates ceased to be Employers or otherwise participate in the Plan; and CENG established and adopted the CENG Plan for the benefit of its employees and certain former Participants in this Plan. As of the CENG Effective Date, the CENG Plan and its related trust received a spin off of assets and liabilities with respect to each employee, former employee, and surviving spouse of a former employee of CENG (or any affiliate or subsidiary thereof the employees of which participated in this Plan prior to the CENG Effective Date) who, immediately prior to the CENG Effective Date, was either (1) an active Participant under this Plan, (2) an inactive Participant or Disabled Participant under this Plan who was entitled to a benefit under this Plan immediately prior to the CENG Effective Date and who was an Employee of an Employer immediately prior to his or her Severance From Service Date or (3) a Surviving Spouse of an individual who would have been described in (1) or (2) had he or she not died prior to the CENG Effective Date. No individual described in the previous sentence shall be entitled to a benefit under or continued participation in the Plan after the CENG Effective Date (except to the extent such individual's benefit is subsequently spun off from the CENG Plan back to this Plan pursuant to 9.4(b) or to the extent such individual is entitled to participate and earn only future benefits under this Plan because he or she is rehired by the Company (or any subsidiary or affiliate thereof the employees of which then participate in the Plan in accordance with the designation of the Board of Directors as reflected in Appendix G) under circumstances where his or her benefit is not spun off from the CENG Plan to this Plan pursuant to this 9.4).

9.4(b) Direct Transfers from CENG—This Plan and the associated Trust will receive a spin off of assets and liabilities from the CENG Plan with respect to each eligible Full-Time Employee of the Company or those designated subsidiaries and affiliates of the Company reflected in Appendix G whose employment is transferred by CENG directly from CENG (or any affiliate or subsidiary thereof the employees of which participate in the CENG Plan) to an Employer after the CENG Effective Date and this Plan and the associated Trust will spin off assets and liabilities to the CENG Plan and its trust with respect to each Former Employee whose employment is transferred by the Company directly from the Company (or a designated subsidiary or affiliate of the Company reflected in Appendix G) to CENG (or any affiliate or subsidiary thereof the employees of which participate in the Prior Plan) after the CENG Effective Date. No Employee or Former Employee of the Employer shall be entitled to a benefit or continued participation in the Plan (or CENG Plan, as the case may be) after the date the assets and liabilities with respect to such employee's benefit are spun off from this Plan and its Trust to the CENG Plan and its trust (or from the CENG Plan and its trust to the Plan and its Trust, as the case may be, and in all cases except to the extent such employee's benefit is subsequently spun back to the other plan pursuant to this paragraph). Under no circumstances shall any individual transferred pursuant to this paragraph be entitled to benefits under this Plan and the CENG Plan (or any other qualified defined benefit pension plan sponsored by the Company, CENG or any of their subsidiaries or affiliates).

9.4(c) Automatic PEP Participation—Except as provided in the next sentence, each Transferred Participant shall become a Participant in the PEP on the date he/she becomes a Full-Time Employee pursuant to the transfer of employment described in 9.4(b). Notwithstanding the foregoing, each Transferred Participant that was a participant in the Traditional Pension Plan immediately prior to the CENG Effective Date and subsequently remained a participant in the corresponding component of the CENG Plan continuously from the CENG Effective Date until the Participant's Transfer Date shall become a Participant in the Traditional Pension Plan on the date he/she becomes a Full-Time Employee pursuant to the transfer of employment described in 9.4(b).

9.4(d) Minimum Benefit—

(i) Traditional Pension Plan—Notwithstanding anything in the Plan to the contrary, the Gross Pension payable to a Transferred Participant in the Traditional Pension Plan under 3.3(a), 3.3(b), 3.3(c), or 3.3(d) shall not be less than the Gross Pension payable to such Participant at the applicable retirement date under the CENG Plan determined immediately prior to such Participant's Transfer Date. For a Transferred Participant in the Traditional Pension Plan, any applicable actuarial adjustment under 3.2(b) shall include periods of active employment recognized as such for purposes of the corresponding actuarial adjustment under the CENG Plan prior to the Transfer Date.

(ii) PEP—Notwithstanding anything in the Plan to the contrary: (a) the Gross Pension payable to a Transferred Participant in the PEP under 3.3(f) or 3.3(g) shall not be less than the Gross Pension or single life annuity payable to such Participant at the Benefit Commencement Date determined under the applicable CENG Plan formula based on the plan provisions, factors and all components of such formula as in effect immediately prior to the Participant's Transfer Date including, for a PEP formula, the Participant's Total Pension Credits and Final Average Annual Pay determined under the applicable CENG Plan as of such date and the provisions of the applicable CENG Plan (including, as applicable, the Annuity Factor and Deferred Annuity Factor) as in effect on such date, and (b) the Gross Pension payable to a Transferred Participant in the PEP under 3.3(e) shall not be less than the Present Value of the deferred annuity payable as of the Participant's Normal Retirement Date under the applicable CENG Plan formula, where such annuity shall be determined immediately prior to the Participant's Transfer Date based on the plan provisions, factors and all components of such formula as in effect immediately prior to the Participant's Transfer Date including, for a PEP formula, the Participant's Total Pension Credits and Final Average Annual Pay determined under the applicable CENG Plan formula and the other provisions of the applicable CENG Plan as in effect on such date.

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IN WITNESS WHEREOF, this restatement and the appendices attached thereto, effective January 31, 2012, were duly executed on this _______ day of January, 2012.

____

Mary Lauria
Chief Human Resources Officer

APPENDIX A

DEFINITIONS

A-1 “Adjusted Employment Commencement Date” means, with respect to an Employee who terminates employment with the Employer and is subsequently reemployed, the date that is determined by subtracting the period of Credited Service and/or Vesting Service that is restored upon reemployment from the date on which the Employee accumulated one hour of service (i.e., each hour for which an Employee is directly or indirectly paid or entitled to payment by an Employer for the performance of duties) after reemployment.

A-2 “Administrative Committee” means the committee appointed by the Chief Executive Officer of the Company as set forth in 6.4.

A-3 “Alternate Beneficiary” means an individual person(s) and/or trust(s) who is entitled to receive distributions under this Plan upon or after the death of a PEP Participant or Traditional Plan Participant.

A-4 “Annual Interest Rate” means (1) on and after January 1, 2008, the rate of interest specified under Code Section 417(e)(3) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67 and (2) prior to January 1, 2008, the annual rate of interest on 30-year Treasury securities, in each case, for the November of the Plan Year immediately preceding the Plan Year in which the first day of the month following the Participant’s Severance From Service Date occurs. Effective January 1, 2008, if the Plan is terminated, for purposes of converting a lump sum benefit to an annuity or converting an annuity to a lump sum, the Annual Interest Rate shall be equal to the average of the rates of interest used under this A-4 during the 5-year period ending on the termination date.

A-5 “Annuity Factor” means the factor which is used to convert a PEP Gross Pension lump sum to an annuity. The factor is based on a Participant’s age at the Benefit Commencement Date, the mortality table described in Code Section 417(e)(3), and the Annual Interest Rate. For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table used for purposes of satisfying the requirement of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2001-62 and for distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table used for purposes of satisfying the requirements of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2007-67. Notwithstanding the foregoing, the following increase is made to the Annual Interest Rate in determining the Annuity Factor: if (i) the Participant is eligible for Early Retirement under 2.2 on his/her Severance From Service Date or (ii) the Participant becomes a Disabled Participant on or after January 1, 1994, the Participant completes at least ten years of Credited Service prior to the date the Participant first benefits under the Disability Plan, and the Participant ceases to be a Disabled Participant on or after age 55 and prior to age 65.

Age at Benefit Commencement Date	Increase in Annual Interest Rate
50 to 62	+1.0%
63	+0.6%
64	+0.3%
65 or older	+0.0%

If the Surviving Spouse of a Participant in PEP chooses to receive an annuity under 5.8, the Surviving Spouse's age as of the date the annuity begins shall be used in place of the Participant's age at the Benefit Commencement Date to determine the Annuity Factor and the increase in the Annual Interest Rate in determining the Annuity Factor described in the preceding sentence is not applicable.

A-6 "Applicable Interest Rate" means, as set forth in Code Section 417(e)(3)(B), the interest rate which would be used (as of the effective date of the distribution) by the Pension Benefit Guaranty Corporation for purposes of determining the present value of a lump sum distribution on plan termination.

A-7 "Appropriate Request" means a written request by a Participant delivered to the Plan Administrator or his/her designated representative.

A-8 "Average Annual Pay" means for a PEP Participant the average, as described in the next sentence, of the following forms of eligible pay: (i) the base rate of pay of an Employee (before any reductions, and excluding (a) overtime, (b) bonuses and incentives other than certain license bonuses set forth in Appendix I, Part 1 and (c) other forms of extra compensation) plus (ii) bonuses and/or incentives set forth in Appendix I, Part 2, paid by the Employer to an Employee, plus (iii) any military differential wage payments (as defined in Section 3401(h)(2) of the Code). The average is calculated by computing the above amounts paid during the 60-month period (in five consecutive 12 month increments) ending on the last day of the month which includes the Severance From Service Date (the date as of which benefits begin under the Disability Plan in the case of a Disabled Participant) including the base rate of pay described in (i) which the Employee would have been paid for the month which includes the Severance From Service Date if he/she had worked to the end of such month to the last 12 month increment, and then taking the average of the three 12-month periods during which the highest amounts were paid. The base salary of an Employee on unpaid leave of absence shall be considered paid for purposes of calculating Average Annual Pay. For purposes of (i), only license bonuses set forth in Appendix I, Part 1 will be included in the computation of Average Annual Pay. For purposes of (ii), only bonuses and/or incentives that are set forth in Appendix I, Part 2 will be included in the computation of Average Annual Pay. The eligible pay of each Participant for each 12-month increment shall not exceed the limitations set forth in Appendix B, Section B-3. To determine Average Annual Pay for a Transferred Participant, amounts described in (i) and (ii) of this section shall include amounts paid by CENG or other Employer under the applicable CENG Plan, but only to the extent that such amounts (x) would be included for purposes of calculating the Transferred Participant's Average Annual Pay under the applicable CEG PEP Plan if such amounts had been paid by an Employer under this Plan, and (y) were paid during the 60-month period (in five consecutive 12-month increments) ending on the last day of the month that includes the Transferred Participant's Severance From Service Date described above. For a Transferred Participant, depending on the Participant's Severance From Service Date, the Participant's Transfer Date may be within the 60-month period described in A-8 or such period may be entirely after the Participant's Transfer Date.

A-9 “Average Pay” means for a Traditional Pension Plan Participant (i) the base rate of pay of an Employee (before any reductions, and excluding (a) overtime, (b) bonuses and incentives other than certain license bonuses set forth in Appendix I, Part 1 and (c) other forms of extra compensation), for the most current 730 days of active employment (but ending on the date as of which benefits begin under the Disability Plan in the case of a Disabled Participant) excluding any February 29ths, divided by 24, plus (ii) certain bonuses and/or incentives set forth in Appendix I, Part 2 paid by the Employer to an Employee during the same period described in (i), but including any February 29ths, divided by 24, plus (iii) any military differential wage payments (as defined in Section 3401(h)(2) of the Code). The base salary of an Employee on unpaid leave of absence shall be considered paid for purposes of calculating Average Pay. For purposes of (i), only license bonuses set forth in Appendix I, Part 1 will be included in the computation of Average Pay. For purposes of (ii), only bonuses and/or incentives set forth in Appendix I, Part 2 will be included in the computation of Average Pay. The eligible pay of each Participant for the most current 12-month period of active employment and for the immediately preceding 12-month period shall not exceed the limitations set forth in Appendix B, Section B-3. To determine Average Pay for a Transferred Participant, amounts described in (i) and (ii) shall include amounts paid by CENG or other Employer under the CENG Traditional Plan, but only to the extent that such amounts (x) would be included for purposes of calculating the Transferred Participant’s Average Pay under the CEG Traditional Plan if such amounts had been paid by an Employer under this Plan, and (y) were paid during the most current 730 days of active employment described above. For a Transferred Participant, depending on the Participant’s Severance From Service Date, the Participant’s Transfer Date may be within the 730 day period described in A-9 or such period may be entirely after the Participant’s Transfer Date.

A-10 “Benefit Commencement Date” means the date as of which the Participant’s benefits, if any, under the Plan commence.

A-11 “Board of Directors” means the Board of Directors of the Company.

A-11a “CENG” means Constellation Energy Nuclear Group, LLC, and its successors and assigns.

A-11b “CENG Effective Date” means November 6, 2009.

A-11c “CENG Plan” means the applicable plan sponsored by CENG under which a Transferred Participant participated immediately prior to his or her Transfer Date, which plan is either (a) the Pension Plan of Constellation Energy Nuclear Group, LLC, which has two parts known as the “CENG Traditional Plan” and the “CEG PEP Plan,” (b) Appendix Ginna of the Pension Plan of Constellation Energy Nuclear Group, LLC or (c) the Nine Mile Point Pension Plan, each of which is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code and its related trust is intended to be tax-exempt under Section 501(a) of the Code. A-12 “Code” means the Internal Revenue Code of 1986, as amended or replaced from time to time.

A-13 “Company” means Constellation Energy Group, Inc., and its successors and assigns.

A-14 “Credited Service” means the period that is taken into account to determine a Participant’s Gross Pension: (i) during a Participant’s employment with the Employer while classified as a Full-Time Employee (other than a leased employee described in Code Section 414(n) or a co-op, work study or summer employee), or (ii) while a Disabled Participant if such Participant has at least ten years of Credited Service prior to the date as of which the Participant first receives benefits under the Disability

Plan, and becomes a Disabled Participant on or after January 1, 1994. Credited Service is computed as described in 4.3. A Transferred Participant's Credited Service shall include Credited Service under the applicable CENG Plan as determined immediately prior to the Transfer Date. Credited Service shall exclude any periods of military service as described in Section 4.4, unless otherwise required by applicable law.

A-15 "Deferred Annuity Factor" means 1.04 η where η equals the number of years and fractions of a year between the Participant's Severance From Service Date and Benefit Commencement Date. If the Participant works less than a full month,, then full credit will be given for the entire month.

A-16 "Disability Plan" means the Constellation Energy Group, Inc. Long-Term Disability Plan, the Constellation Energy Group, Inc. Disability Insurance Plan, or any successor plan.

A-17 "Disabled Participant" means a Participant who is disabled as that term is defined in the Disability Plan and who is receiving benefits under the Disability Plan. Participants who became Disabled Participants prior to January 1, 1994 are subject to the provisions at Appendix C, Section C-10.

A-18 "Disability Retirement" means a type of retirement available to a Disabled Participant (i) who became a Disabled Participant on or after January 1, 1994, (ii) who is a Participant in the Traditional Pension Plan, (iii) who has at least ten years of Credited Service prior to the date as of which the Participant first receives benefits under the Disability Plan, and (iv) who is at least age 50 (but not yet age 65) when he/she ceases benefiting under the Disability Plan because he/she is determined to be no longer disabled under the terms of such plan.

A-19 “Early Retirement” means a type of retirement available to a Participant who, on his/her Severance From Service Date is at least age 55, and has at least ten years of Credited Service.

A-20 “Early Retirement Adjustment Factor” means, for a Participant in the Traditional Pension Plan with a Benefit Commencement Date that is on or after the date that the Participant attains age 55, or for a Disabled Participant who is age 50 or older, 100 percent less 1/4 of one percent for each month that the Participant is less than age 65 on the Participant’s Benefit Commencement Date. Notwithstanding anything to the contrary, the Early Retirement Adjustment Factor for a Participant in the Traditional Pension Plan who has completed at least 35 years of Credited Service as of his/her Severance From Service Date is 100 percent less 1/4 of one percent for each month that the Participant is less than age 62 on the Participant’s Benefit Commencement Date. For purposes of these calculations, the month of the Participant’s 62nd or 65th birthdays, as appropriate, is excluded.

A-21 “Employee” means any person who is employed by the Employer, but excludes any person who is in the sole judgment of the Employer an independent contractor. Employee shall include leased employees within the meaning of Code Section 414(n)(2), which, effective for Plan Years beginning on or after January 1, 1997, includes any person (other than an Employee of an Employer) who pursuant to an agreement between an Employer and any other person has performed services for an Employer on a substantially full-time basis for a period of at least one year, and such services are performed under the primary direction or control of an Employer, unless the leased employees are covered by a plan described in Code Section 414(n)(5) and such leased employees do not constitute more than 20% of the Employer's nonhighly compensated work force described in Code Section 414(n)(5)(C)(ii).

An Employee may be a Full-Time Employee or an On-Call Employee. A Full-Time Employee is any Employee employed on an ongoing and regular basis who has a basic workweek generally consisting of 40 hours, although Employees who work a Part-Time Schedule with a basic workweek of less than 40 hours are also considered to be Full-Time Employees. On-Call Employees constitute a reasonable classification of Employees who do not have a basic workweek, but rather work on an irregular, "on call" basis and do not participate in any "time off" or related benefit plans and are compensated only for those hours actually worked.

A-22 "Employer" means the Company and any successor which shall maintain this Plan, and any subsidiaries or other affiliates required to be aggregated with the Company under Code Section 414(b), (c), (m) or (o).

A-23 "Employment Commencement Date" means, with respect to an Employee who is not described in "Adjusted Employment Commencement Date," the date on which an Employee first performs an hour of service (i.e., each hour for which an Employee is directly or indirectly paid or entitled to payment by an Employer for the performance of duties) for the Employer.

A-24 "ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time.

A-24a “Executive Group” means the Company’s Chief Executive Officer, Chief Financial Officer, General Counsel and Chief Human Resources Officer, collectively.

A-25 “Final Average Annual Pay” means for a Participant in PEP, the Average Annual Pay computed as of the Participant’s Severance From Service Date.

A-26 “Final Average Pay” means for a Participant in the Traditional Pension Plan, the Average Pay computed as of the Participant’s Severance From Service Date. A-27 “Former Employee” means an individual who was formerly an Employee, but who has ceased employment with the Employer.

A-28 “Full-Time Employee” see the definition of “Employee.”

A-29 “Gross Pension” means the monthly benefit or the lump sum benefit computed under a pension formula, before any adjustments.

A-30 “Investment Committee” means the committee appointed by the Chief Executive Officer of the Company as set forth in 6.5.

A-31 “Normal Retirement” means a type of retirement available to a Participant who, on the day preceding his/her Normal Retirement Date, is actively employed or a Disabled Participant and has at least five years of Credited Service.

A-32 “Normal Retirement Date” means the first day of the first month after the later of (i) the date of the Participant’s 65th birthday or (ii) the date which is the fifth anniversary of the Participant’s Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date).

A-33 “Normal Retirement Service Percentage” means (i) 1/12 of 1-1/2 percent for each of a Traditional Pension Plan Participant’s first 240 months of Credited Service, plus (ii) 1/12 of 1-1/3 percent for each of the next 180 months of Credited Service.

A-34 “On-Call Employee” —see the definition of “Employee.”

A-34a “Part-Time Schedule” means a job that is scheduled for fewer than either eight hours per base tour or five base tours per payroll week on a regular and ongoing basis. It is intended that this definition conform to the usage of the term part-time in the Company’s Employee Handbook.

A-35 “Participant” means any Employee or Former Employee who is entitled to benefits under the Plan.

A-36 “Pension Equity Plan or ‘PEP’” means the Plan in effect as of January 1, 2000, for those who become Participants pursuant to 1.1 and those Participants who choose it pursuant to 1.2. For a Transferred Participant, “Pension Equity Plan” or “PEP” also means the Plan in effect for those who become Participants pursuant to 9.4(c) who did not become participants in the Traditional Pension Plan pursuant to 9.4(c).

A-37 “Plan” means the Pension Plan of Constellation Energy Group, Inc., which includes the both the Pension Equity Plan and the Traditional Pension Plan.

A-38 “Plan Administrator” means the Director—Benefits of the Company (or the successor to that function).

A-39 “Plan Year” means the Plan’s accounting year of 12 months beginning on January 1 of each year and ending the following December 31.

A-40 “Post-retirement Survivor Annuity” means a Survivor Annuity paid when a Participant with vested benefits under the Traditional Pension Plan dies on or after the Participant’s Benefit Commencement Date.

A-41 “Post-retirement Survivor Benefit” means a survivor benefit paid when a Participant with vested benefits under PEP dies on or after the Participant’s Benefit Commencement Date.

A-42 “Preretirement Survivor Annuity” means a Survivor Annuity paid when a Participant with vested benefits under the Traditional Pension Plan dies before the Participant’s Benefit Commencement Date.

A-43 “Preretirement Survivor Benefit” means a survivor benefit paid when a Participant with vested benefits under PEP dies before the Participant’s Benefit Commencement Date.

A-44 “Present Value” means, as set forth in Code Section 417(e)(3), an amount calculated by using the UP-1984 Mortality Table and (i) by using an interest rate equal to the Applicable Interest Rate if such Present Value is not in excess of $25,000, and (ii) by using an interest rate equal to 120 percent of the Applicable Interest Rate if such Present Value exceeds $25,000 (as determined under (i)). In no event shall the Present Value determined under (ii) be less than $25,000.Notwithstanding the preceding, for payments made as of a date on or after January 1, 2000, “Present Value” means an amount calculated using the interest rate described below and the mortality table described in Code Section 417(e)(3). Prior to January 1, 2008, the interest rate shall be the lesser of (i) the annual interest rate on 30-year Treasury securities for November of the Plan Year immediately preceding the Plan Year that contains the date as of which the payment is made, and (ii) for payments made as of a date on or after January 1, 2000 and before January 1, 2001, the annual interest rate on 30-year Treasury securities for the first full calendar month preceding the date as of which the payment is made. On and after

January 1, 2008, the interest rate shall be rate of interest specified under Code Section 417(e)(3) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67. Effective January 1, 2008, if the Plan is terminated, for purposes of converting a lump sum benefit to an annuity or converting an annuity to a lump sum, the interest rate described above shall be equal to the average of the rates of interest used under this A-44 during the 5-year period ending on the termination date.

In calculating the "Present Value" of a benefit payable to a Participant, the benefit shall be treated as commencing as of the later of the Participant's Normal Retirement Date and the Benefit Commencement Date. In calculating the "Present Value" of a benefit payable to the Surviving Spouse of a Participant in the Traditional Pension Plan, the benefit shall be treated as commencing as of the first day of the month following the Participant's 55th birthday.

For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table used for purposes of satisfying the requirements of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2001-62. For distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table used for purposes of satisfying the requirements of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2007-67.

A-44a "Section 415(c) Compensation" means all amounts required to be reported under Code Sections 6041, 6051, and 6052 (wages, tips, and other compensation as reported on Form W-2). This includes wages, within the meaning of Code Section 3401(a), and all other payments of compensation to an Employee by the Employer (in the course of the Employer's trade or business) for which the Employer is required to furnish the Employee a written statement under Code Sections 6041(d), 6051(a)(3), and 6052. In addition, an Employee's compensation includes any elective deferrals (as defined in Code Section 402(g)(3)), and any amount which is contributed or deferred by the Employer at the election of the Employee and which is not includible in gross income of the Employee by reason of Code Sections 125 or 132(f)(4). An Employee's compensation shall be determined without regard to any rules under Code Section 3401(a) that limit the remuneration included in wages based on the nature or location of the employment or the services performed.

To the extent applicable, Section 415(c) Compensation shall not include amounts in excess of the statutory dollar limitation under Code Section 401(a)(17), as described in Section B-3. Section 415 Compensation includes any differential wage payments (as defined in Section 3401(h)(2) of the Code).

A-45 "Severance From Service Date" means the date on which a Participant ends active employment with the Employer for purposes of the Plan. A Participant ends active employment on the earliest of the date that the Participant quits, retires, is discharged, dies, or the first anniversary of the first date of a period in which the Employee remains absent from service with the Employer for any reason other than quit, retirement, discharge or death.

A-46 Deleted.

A-47 "Surviving Spouse" means, with respect to a Preretirement Survivor Annuity or the Preretirement Survivor Benefit, the person married to a Participant on the Participant's date of death. Surviving Spouse means, with respect to a Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit, the person married to a Participant on the Participant's Benefit Commencement Date.

A-48 “Survivor Annuity” means a monthly benefit payable to the Surviving Spouse or Alternate Beneficiary for the life of the Surviving Spouse or Alternate Beneficiary.

A-49 “Total Pension Credits” means the pension credits provided to a Participant in PEP. A Participant’s pension credits shall equal the sum of (i) 0.05 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (ii) 0.10 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (iii) 0.15 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

A-50 “Traditional Pension Plan” means the Plan in effect as of January 1, 2000, for those Participants who choose it pursuant to Section 1.2, which is the enhancement to the Plan in effect prior to that date.

A-50a “Transfer Date” means the effective date of the spin off of a Transferred Participant’s benefit from the applicable CENG Plan and merger into this Plan pursuant to 9.4(b).

A-50b “Transferred Participant” means each (a) Full-Time Employee of the Company or those designated subsidiaries and affiliates of the Company reflected in Appendix G with respect to whom assets and liabilities are spun off from the applicable CENG Plan and its related trust and merged into this Plan and its Trust pursuant to 9.4(b) of this Plan.

A-51 “Treasury” means the Federal Treasury Department.

A-52 “Trust” means the trust established for the purpose of holding and managing Plan assets.

A-53 “Trustee” means Citibank, N.A. or any successor Trustee appointed by the Board of Directors.

A-54 “Vesting Service” means the period of a Participant’s employment with the Employer that is taken into account to determine whether a Participant has a vested right to receive a pension. Vesting Service is computed as described in 4.4. A Transferred Participant’s Vesting Service shall include Vesting Service under the applicable CENG Plan as determined immediately prior to the Transfer Date.

APPENDIX B

LIMITATIONS

B-1 Maximum Pension Payment: Code Limits—

(a) Notwithstanding any other provision in the Plan to the contrary, the limitations, adjustments and other requirements prescribed in this B-1 shall at all times be administered in a manner which will result in compliance with the provisions of Code Section 415 and the regulations thereunder, the terms of which are specifically incorporated herein by reference.

(b) For limitation years beginning on or after July 1, 2007, in addition to other limitations set forth in the Plan and notwithstanding any other provisions of the Plan, the "Annual Benefit" otherwise payable to a Participant under the Plan shall not exceed the "Maximum Permissible Benefit" (as defined below). If the benefit the Participant would otherwise accrue in a limitation year would produce an Annual Benefit in excess of the Maximum Permissible Benefit, the benefit shall be limited (or the rate of accrual reduced) to a benefit that does not exceed the Maximum Permissible Benefit. If the Participant is, or ever has been, a participant in another qualified defined benefit plan (without regard to whether the plan has been terminated) maintained by the Employer or its predecessor (within the meaning of Section 1.415(f)-1(c) of the Treasury Regulations), the sum of the Participant's annual benefit from all such plans may not exceed the Maximum Permissible Benefit. The Annual Benefit of a Participant may be increased as the Maximum Permissible Benefit is adjusted in accordance with Code Section 415(d), but only prior to the commencement of pension payments.

(c) For purposes of this B-1 for limitation years beginning on or after July 1, 2007, the “Annual Benefit” means the Gross Pension payable annually under the terms of the Plan in the form of a straight life annuity (exclusive of any benefit not required to be considered for purposes of applying the limitations of Section 415 of the Code). Where the Gross Pension is payable other than a straight life annuity, the benefit shall be adjusted (pursuant to B-1(g)) to an actuarially equivalent straight life annuity that begins at the same time as such other form of benefit and is payable on the first day of each month before applying the limitations of this B-1. The determination of the Annual Benefit shall take into account benefits transferred from another defined benefit plan, other than transfers of distributable benefits pursuant to Section 1.411(d)-4, Q&A-3(c) of the Treasury Regulations, but shall disregard benefits, if any, attributable to employee contributions or rollover contributions.

(d) For limitation years beginning on or after July 1, 2007 for purposes of this B-1, “Maximum Permissible Amount” means the lesser of (i) or (ii) below:

(i) $180,000, adjusted under Section 415(d) of the Code effective January 1 of each year and payable in the form of a straight life annuity. This limitation as adjusted under Section 415(d) of the Code will apply to limitation years ending with or within the calendar year for which the adjustment applies.

(ii) 100% of the Participant’s high three-year compensation, or, if the Participant does not have three consecutive years of service, 100% of the Participant’s average compensation over the longest consecutive period of service (including fractions of years, but not less than one year), payable in the form of a straight life annuity. In the case of a Participant who is rehired by the Employer after a severance from employment, the Participant's high three-year average compensation shall be calculated excluding all years for which the Participant performs no services for and receives no compensation from the Employer and by treating the years immediately preceding and following the break as consecutive.

(iii) Notwithstanding anything in this section to the contrary, the benefit otherwise accrued or payable to the Participant under the Plan shall be deemed not to exceed the Maximum Permissible Benefit if the retirement benefits payable for a limitation year under any form of benefit with respect to such Participant under this Plan and all other defined benefit plans (without regard to whether a plan as been terminated) ever maintained by the Employer do not exceed $10,000 multiplied by a fraction, the numerator of which is the Participant's number of years (or part thereof, but not less than one year) of service (not to exceed 10) with the Employer, and the denominator of which is 10; and the Employer (or predecessor employer) has not at any time maintained a defined contribution plan in which the Participant participated.

(e) For limitation years beginning on or after July 1, 2007 for purposes of this B-1, "compensation" means Section 415(c) Compensation. In addition, for purposes of this B-1 for limitation years beginning on or after July 1, 2007, compensation shall also include amounts paid by the later of 2 1/2 months after a Participant's severance from employment with the Employer or the end of the limitation year that includes the date of such severance from employment if the payment is regular compensation for services (within the meaning of Section 1.415(c)-2(e)(3)(ii) of the Treasury Regulations), commissions, bonuses or other similar payments paid after the Participant's severance from employment (but by the later of 2 1/2 months after such severance from employment or the end of the limitation year that includes the date of such severance from employment) that would have been paid to the Participant absent such severance from employment had the Participant continued in employment with the Employer.

Any payments not described above shall not be considered compensation for purposes of this B-1 for limitation years beginning on or after July 1, 2007 if paid after severance from employment, even if paid by the later of 2 1/2 months after the date of severance from employment or the end of the limitation year that includes the date of such severance from employment, except:

(i) payments to an individual who does not currently perform services for the employer by reason of qualified military service (within the meaning of Code Section 414(u)(1)) to the extent these payments do not exceed amounts the individual would have received if the individual would had continued to perform services for the Employer rather than entering qualified military service; or

(ii) compensation paid to a Participant who is permanently and totally disabled, as defined in Code Section 22(e)(3), provided that salary continuation applies to all Participants who are permanently and totally disabled for a fixed or determinable period, or the Participant was not a highly compensated employee immediately before becoming disabled.

Back pay, within the meaning of Section 1.415(c)-2(g)(8) of the Treasury Regulations, shall be treated as compensation for the limitation year to which the back pay relates to the extent that back pay represents wages and compensation that would otherwise be included as “compensation” as defined herein.

(f) For purposes of complying with Code Section 415, a limitation year means the calendar year.

(g) Adjustments to Annual Benefit and Limitations

(i) For purposes of applying the limits of Code Section 415 and this B-1, for limitation years beginning on or after July 1, 2007, a benefit that is payable in any form other than a straight life annuity and that is not subject to Section 417(e)(3) of the Code must be adjusted to an actuarially equivalent straight life annuity that equals the greater of the annual amount of the straight life annuity (if any) payable under the Plan at the same annuity starting date, and the annual amount of a straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant’s form of benefit computed using an interest rate of 5% and the applicable mortality table for that annuity starting date.

(ii) For Plan benefits subject to Section 417(e)(3) of the Code, the actuarially equivalent straight life annuity for annuity starting dates beginning after 2005 is equal to the greatest of (i) the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant’s form of benefit, computed using the interest rate and mortality table (or other tabular factor) specified in the Plan for adjusting benefits in the same form; (ii) the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant’s form of benefit, computed using a 5.5 % interest rate assumption and the applicable mortality table; and (iii) the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant’s form of benefit, computed using the applicable interest rate and applicable mortality table, divided by 1.05.

(iii) For Plan benefits subject to Section 417(e)(3) of the Code with an annuity starting date in a Plan Year beginning in 2004 or 2005, the actuarially equivalent straight life annuity is equal to the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant's form of benefit, computed using whichever of the following produces the greater annual amount: (i) the interest rate and mortality table (or other tabular factor) specified in the Plan for adjusting benefits in the same form; and (ii) a 5.5 % interest rate assumption and the applicable mortality table.

(iv) For limitation years beginning on or after July 1, 2007, if the benefit of a Participant begins prior to age 62, the defined benefit dollar limitation (described in B-1(d)(i) above, adjusted as applicable) applicable to the Participant at such earlier age is limited to the lesser of (1) the annual amount of a benefit payable in the form of a straight life annuity commencing at the Participant's annuity starting date that is the actuarial equivalent of the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required), with actuarial equivalence computed using a 5% interest rate assumption and the applicable mortality table and expressing the Participant's age based on completed calendar months as of the annuity starting date or (2) the product of the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required) multiplied by the ratio of the annual amount of the immediately commencing straight life annuity at the Participant's annuity starting date to the annual amount of the immediately commencing straight life annuity at age 62, both determined without applying the limitations of Code Section 415.

(v) For limitation years beginning on or after July 1, 2007, if the benefit of a Participant begins after the Participant attains age 65, the defined benefit dollar limitation (described in B-1(d)(i) above, adjusted as applicable) is the lesser of (1) the annual amount of a benefit payable in the form of a straight life annuity commencing at the Participant's annuity starting date that is the actuarial equivalent of the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required), with actuarial equivalence computed using a 5% interest rate assumption and the applicable mortality table for that annuity starting date (and expressing the Participant's age based on completed calendar months as of the annuity starting date) or (2) the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required) multiplied by the ratio of the annual amount of the adjusted immediately commencing straight life annuity under the Plan at the Participant's annuity starting date to the annual amount of the adjusted immediately commencing straight life annuity under the Plan at age 65, both determined without applying the limitations of Code Section 415. For this purpose, the adjusted immediately commencing straight life annuity under the Plan at the Participant's annuity starting date is the annual amount of such annuity payable to the Participant, computed disregarding the Participant's accruals after age 65 but including actuarial adjustments even if those actuarial adjustments are used to offset accruals; and the adjusted immediately commencing straight life annuity under the Plan at age 65 is the annual amount of such annuity that would be payable under the Plan to a hypothetical Participant who is age 65 and has the same accrued benefit as the Participant.

(vi) If the Participant has less than 10 years of participation in the Plan, the defined benefit dollar limitation (described in B-1(d)(i) above, adjusted as applicable) shall be multiplied by a fraction, the numerator of which is the number of years (or part thereof, but not less than one year) of participation in the Plan, and the denominator of which is 10. If the Participant has less than 10 years of service, the defined benefit compensation limit (described in B-1(d)(ii) above) shall be multiplied by a fraction, the numerator of which is the number of years (or part thereof, but not less than one year) of service with the employer, and the denominator of which is 10.

(vii) In applying the limitations in Code Section 415(b), the Code Section 415(b)(2)(E) changes made by the Uruguay Round Agreements Act (GATT) and Small Business Job Protection Act of 1996 shall be effective as of January 1, 2000. For this purpose, the time for determining the applicable interest rate under Code Section 417(e)(3) shall be the November of the Plan Year immediately preceding the Plan Year that contains the Benefit Commencement Date. For distributions with a Benefit Commencement Date on or after January 1, 2003, the applicable mortality table used for purposes of adjusting any benefit or limitation under Code Sections 415(b)(2)(B), (C), or (D) is the table prescribed in Revenue Ruling 2001-62. For limitation years beginning on or after July 1, 2007, the applicable interest rate shall be the first, second, and third segment rates described in Code Section 417(e)(3)(C), for the November of the Plan Year immediately preceding the Plan Year that contains the Benefit Commencement Date and the applicable mortality table shall be the mortality table, as modified by the Secretary of Treasury, described in Section 417(e)(3)(B) of the Code that applies as of the Benefit Commencement Date.

(h) All members of a controlled group of corporations (as defined in Code Section 414(b), commonly controlled trades or businesses (as defined in Code Section 414(c)), or affiliated service groups (as defined in Code Section 414(m)) that include the Employer, and any other entity required to be aggregated with the Employer pursuant to Code Section 414(o) shall be considered as a single employer for purposes of applying the limitations described in Section 415 of the Code and this B-1.

(i) If (i) a Participant is also benefiting under another defined benefit plan sponsored by the Employer or its predecessor, and (ii) reductions in either the amount of the Participant's annual benefit under the Plan or the amount of the Participant's annual benefit under such other plan (or both) are necessary to comply with Code Section 415, a reduction in the Participant's annual benefit under the Plan shall be made to the extent necessary to comply with Code Section 415, prior to any reduction in the Participant's annual benefit any other plan(s).

(j) The application of the provisions of this B-1 shall not cause the Maximum Permissible Benefit for any Participant to be less than the Participant's accrued benefit as of the end of the last limitation year beginning before July 1, 2007 under the provisions of the Plan that were adopted and in effect before April 5, 2007.

B-2 Maximum Pension Payment: Treasury Regulation Limits—Notwithstanding any other provision in the Plan to the contrary, pension payments to the top 25 highly compensated employees and former highly compensated employees, as those terms are defined in Code Section 414(q) and the related regulations, with the greatest compensation (as that term is defined in Code Section 414(s) and the related regulations) in the current Plan Year and any prior Plan Year, shall be restricted as required under Section 1.401(a)(4)-5(b)(3) of the Treasury regulations, unless the exception set forth in such section applies.

B-3 Compensation Limitation Under Code Section 401(a)(17)—In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provision of the Plan to the contrary, for Plan Years beginning on or after January 1, 1994, the annual compensation of each Employee taken into account under the Plan shall not exceed the Omnibus Budget Reconciliation Act of 1993 (hereinafter referred to in this Section B-4 as "OBRA '93") annual compensation limit. The OBRA '93 annual compensation limit is $150,000, as adjusted by the Commissioner of the Internal Revenue Service for increases in the cost of living in accordance with Code Section 401(a)(17)(B). The cost-of-living adjustment in effect for a calendar year applies to any period, not exceeding 12 months, over which compensation is determined (hereinafter referred to as "Determination Period") beginning in such calendar year.

For Plan Years beginning on or after January 1, 1994, any reference in this Plan to the limitation under Code Section 401(a)(17) shall mean the OBRA '93 annual compensation limit set forth in this provision.

If compensation for any prior Determination Period is taken into account in determining an Employee's benefits accruing in the current Plan Year, the compensation for that prior Determination Period is subject to the OBRA '93 annual compensation limit in effect for that prior Determination Period. For this purpose, for Determination Periods beginning before the first day of the first Plan Year beginning on or after January 1, 1994, the OBRA '93 annual compensation limit is $150,000.

Unless otherwise provided under the Plan, each Code Section 401(a)(17) employee's accrued benefit under this Plan will be the greater of the accrued benefit determined for such Employee under 1 or 2 below:

1. The Employee's accrued benefit determined with respect to the benefit formula applicable for the Plan Year beginning on or after January 1, 1994, as applied to the Employee's total years of service taken into account under the Plan for the purposes of benefit accruals, or

2. the sum of:

(a) the Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994, frozen in accordance with Section 1.401(a)(4)-13 of the Treasury regulations; and

(b) the Employee's accrued benefit determined under the benefit formula applicable for the Plan Year beginning on or after January 1, 1994, as applied to the Employee's years of service credited to the Employee for Plan Years beginning on or after January 1, 1994, for purposes of benefit accruals.

For purposes of making the calculation in 2. above, the following rules shall apply:

1. An Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 shall be determined after limiting Average Pay to $228,860 for 1992 and $235,840 for 1993;

2. An Employee’s accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 shall be determined by assuming the Employee is eligible for the early retirement benefits and the early retirement reductions for which the Employee is eligible at the Employee’s Severance From Service Date;

3. An Employee’s accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 shall be determined based on the project and prorate method (i.e., the projected Gross Pension on December 31, 1993 assuming employment until Normal Retirement Date times Credited Service as of December 31, 1993, divided by projected Credited Service at Normal Retirement Date) if the Employee is not eligible for Early Retirement on December 31, 1993. If such an Employee is eligible for Early Retirement on the Employee’s Severance From Service Date, the Employee’s accrued benefit as applied to the Employee’s years of service credited to the Employee for Plan Years beginning on or after January 1, 1994 shall be calculated by subtracting the December 31, 1993 benefit, calculated using the $150,000 compensation limit (reflecting cost-of-living increases in the $150,000 compensation limit) from the benefit at the Employee’s Severance From Service Date based on all service;

4. An Employee who participates in the PEP may receive a lump-sum payment of the Employee’s accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 based on the assumptions in the Plan used to convert an immediate lump sum to a deferred annuity beginning at the Employee’s Normal Retirement Date; and

5. The Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 for an Employee who participates in the PEP is converted to a lump sum based on the assumptions used to determine the Present Value of an accrued benefit or the assumptions that are used to convert a lump-sum benefit under the PEP to a life annuity beginning at the Employee's Normal Retirement Date, whichever results in the larger lump sum.

A Code Section 401(a)(17) employee means an Employee whose current accrued benefit as of a date on or after the first day of the first Plan Year beginning on or after January 1, 1994, is based on compensation for a year beginning prior to the first day of the first Plan Year beginning on or after January 1, 1994, that exceeds $150,000.

Notwithstanding the foregoing, for Plan Years beginning on or after January 1, 2002, the annual compensation of each Employee taken into account under the Plan shall not exceed $200,000, as adjusted for cost of living increases in accordance with Code section 401(a)(17)(B). The cost-of-living adjustment in effect for a calendar year applies to annual compensation for the Determination Period beginning in such calendar year. For purposes of determining benefit accruals in a Plan Year beginning on or after January 1, 2002, the annual compensation taken into account in any Plan Year preceding the Plan Year beginning on January 1, 2002 shall be limited to $200,000.

APPENDIX C

TRANSITION AND HISTORICAL PROVISIONS

C-1 Normal Retirement Service Percentage—Notwithstanding any other provision in the Plan to the contrary, each Participant who (i) was an active Employee of the Employer on December 31, 1975, (ii) continuously accrues Credited Service from such date through the Participant's Normal Retirement Date, and (iii) has accumulated Credited Service on the day prior to the Participant's Normal Retirement Date equal to at least 15 years but less than 20 years, has a Normal Retirement Service Percentage of 30%, adjusted for Part-Time Schedule as provided in 3.4(b) if applicable. This C-1 will not be effective after December 31, 1995.

C-2 Part-Time Schedule Adjustment—Notwithstanding any other provision in the Plan to the contrary, each Participant who (i) was an active Employee of the Employer on December 31, 1975, (ii) continuously accrues Credited Service from such date through the date the Participant quits, retires, is discharged, becomes disabled, or dies, and (iii) could receive a larger Gross Pension if the Part-Time Schedule adjustment provisions of the Plan in effect on December 31, 1975 were currently applicable, will be entitled to such larger Gross Pension.

C-3 Former Susquehanna Transmission Company Employees—Notwithstanding any other provision in the Plan to the contrary, service with the Susquehanna Transmission Company by an Employee who became employed by the Employer because of Baltimore Gas and Electric Company's acquisition of such company, will count as Credited Service and Vesting Service, to the same extent and subject to the same limitations as if such service had been rendered for the Employer. The Gross Pension of any Participant affected by this provision who quits, retires, is discharged, becomes disabled or dies with a vested right to a benefit under the Plan, and who is entitled to an annuity under another arrangement by virtue of such Participant's previous employment with the Susquehanna Transmission Company, will be reduced by the amount of such annuity.

C-4 Voluntary Retirement—Early Receipt of Pension Payments—Notwithstanding any other provisions of the Plan, a Participant who retired under the Voluntary Retirement provisions that were in effect prior to July 1, 1986, may elect to begin receipt of his/her monthly pension payments prior to the Participant's Normal Retirement Date, subject to the adjustment under the early receipt provisions in 3.4(c). Such pension payments shall commence as of the first day of the month designated in writing by the Participant. The month so designated must be a month (i) later than the month during which the Plan Administrator receives the Participant's written election, and (ii) before the Participant's Normal Retirement Date.

C-5 Preretirement Survivor Annuity Coverage For Certain Participants —The provisions of this C-5, and not 5.1 or 5.2, shall apply to a Participant who quit or was discharged from employment with the Employer after September 1, 1974 and before January 1, 1985. If such Participant (i) terminated employment with a vested right to receive a pension payment equal to the Participant's Gross Pension (as computed under the terms of the Plan on the date the Participant terminated active employment), (ii) dies prior to the Participant's Benefit Commencement Date, (iii) was not eligible to elect Preretirement Survivor Annuity coverage while an active Employee, and (iv) makes the election in the following paragraph, then the Surviving Spouse of such Participant will receive a Preretirement Survivor Annuity equal to 50% of such pension (actuarially reduced if necessary to account for the age of the Surviving Spouse and for payment prior to the Participant's Normal Retirement Date).

The Participant's election for the 50% Preretirement Survivor Annuity coverage must be made prior to the Participant's Benefit Commencement Date. The coverage commences on the first day of the month following receipt of the Participant's election by the Plan Administrator. Such coverage automatically ceases as set forth in 5.1(c). The Participant may cancel the coverage, without the consent of the Participant's spouse, by delivering an Appropriate Request to the Plan Administrator prior to the Participant's Benefit Commencement Date. Such cancellation is effective as of the first day of the month following receipt by the Plan Administrator of the Appropriate Request. Cancellation is automatic if the Participant's spouse dies prior to the effective date of the coverage. A Participant's pension payments are not reduced for the cost of coverage.

C-6 Post-retirement Survivor Annuity Coverage for Certain Participants —The provisions of this C-6, and not 5.3 or 5.4, shall apply to a Participant who quit or was discharged from employment with the Employer after September 1, 1974 and prior to January 1, 1976. If such Participant (i) terminates employment with a vested right to receive a pension payment equal to the Participant's Gross Pension (as computed under the terms of the Plan on the date the Participant terminated active employment), (ii) dies on or before the Participant's Benefit Commencement Date, and (iii) makes the election in the following paragraph, then the Surviving Spouse of such Participant will receive a Post-retirement Survivor Annuity equal to 50% of such pension (actuarially reduced if necessary to account for the age of the Surviving Spouse and for payment prior to the Participant's Normal Retirement Date).

The Participant's election for the 50% Post-retirement Survivor Annuity must be made prior to the Participant's Benefit Commencement Date. The Participant may revoke an election, without the consent of the Participant's spouse, by delivering an Appropriate Request to the Plan Administrator prior to the Participant's Benefit Commencement Date. Cancellation is automatic if the Participant's spouse dies prior to the effective date of the coverage. The coverage commences on the Participant's Benefit Commencement Date. Such coverage automatically ceases upon the date of death of the spouse. A Participant's pension payments are reduced to offset the cost of coverage.

Within 90 days prior to such Participant's Benefit Commencement Date, the Plan Administrator will mail to the Participant's last known address (i) written explanation of the terms and conditions of the Post-retirement Survivor Annuity and (ii) an estimate of the relative values of the various optional forms of benefit under the Plan if the fact of marriage and the age of the spouse are known to the Plan Administrator. In the case of a Participant whose Benefit Commencement Date is before or after the Participant's Normal Retirement Date, the Plan Administrator shall mail the written explanation to the Participant by the later of (i) 90 days prior to the Participant's Benefit Commencement Date, or (ii) 7 days after the Plan Administrator is notified of the Participant's intention to retire.

C-7 Participants Who Terminated Employment Before 1989—A Participant who terminated employment prior to January 1, 1989 without a vested right to the Participant's Gross Pension, and who is subsequently reemployed by the Employer, will be subject to the service forfeiture, restoration and vesting provisions currently under this Plan, retroactive to the Employee's original Employment Commencement Date. If retroactive application of these provisions results in a vested right to the Participant's Gross Pension prior to the date of the Participant's termination of employment, Credited Service taken into account to determine such vesting, and Credited Service subsequently accumulated through the date of termination of employment, shall be restored.

A Participant who terminated employment prior to January 1, 1989 with a vested right to the Participant's Gross Pension, and who is subsequently reemployed by the Employer, will be subject to the forfeiture, restoration and vesting provisions currently under this Plan, retroactive to the Employee's original Employment Commencement Date. If retroactive application of these provisions results in a larger amount of potentially restorable Credited Service than the amount of Credited Service actually accumulated prior to the date of the Participant's termination of employment, the larger amount of Credited Service will be restored.

C-8 Voluntary Special Early Retirement Program—Notwithstanding any other provision in the Plan or any Appendix to the contrary, each Participant who under the terms of the Plan is eligible to commence Early Retirement, and who voluntarily elects to commence Early Retirement on or after February 1, 1992 and on or before April 1, 1992, shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations. The Employer also reserves the right to delay the Early Retirement commencement date of eligible Participants until no later than April 1, 1992, if operating condition requirements warrant such a delay. For purposes of this C-8, the enhanced benefit is determined based on the calculation of the

Gross Pension of a Participant entitled to Early Retirement as set forth under 3.3(b), except that the Early Retirement Adjustment Factor shall be computed as follows:

> The Early Retirement Adjustment Factor for Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 60, is 100 percent. For all other Participants, the Early Retirement Adjustment Factor is 100 percent less 1/4 of 1 percent for each month that the Participant is less than age 60 on the Participant's Benefit Commencement Date. For purposes of this calculation, the month of the Participant's 60th birthday is excluded.

The amount of pension payments for Participants entitled to an enhanced benefit under this C-8 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. A Participant who commences Early Retirement under this C-8, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-9 Voluntary Special Early Retirement Program—Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence are eligible for Early Retirement if, as of February 1, 1994 they satisfy the requirements of 2.2 after substituting age 50 for age 55 and 15 years of Credited Service for 20 years of Credited Service. The conditions such Participants must meet are as follows: (1) the Participant makes an election between October 15, 1993 and December 15, 1993 to voluntarily commence Early Retirement on February 1, 1994, and such election shall be irrevocable effective December 15, 1993, and (2) the Participant does not elect to participate in the Baltimore Gas and Electric Company Voluntary Severance Plan. Participants who satisfy the requirements and conditions set forth in the two preceding sentences shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations.

For purposes of this C-9, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under 3.3(b), except that the Early Retirement Adjustment Factor shall be computed as follows:

The Early Retirement Adjustment Factor for Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 60, is 100 percent. For Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 55 but before the date that the Participant attains age 60, the Early Retirement Adjustment Factor is 100 percent less 1/4 of 1 percent for each month that the Participant is less than age 60 on the Participant's Benefit Commencement Date. For all other Participants, the Early Retirement Adjustment Factor is 100 percent less the percentage equal to (i) 15 percent plus (ii) 1/2 of 1 percent for each month that the Participant is less than age 55 on the Participant's Benefit Commencement Date. For purposes of this calculation, the month of the Participant's 55th and 60th birthdays is excluded.

In addition, the enhanced benefit for eligible Participants who have not attained age 62 as of February 1, 1994 will include an additional monthly payment from the Plan. The amount of the payment shall be equal to one-half of the Participant's estimated monthly age 62 Social Security benefits computed assuming no earnings after 1993. The amount of such estimated age 62 Social Security benefits shall be provided to Baltimore Gas and Electric Company by the Social Security Administration and shall be final and not subject to challenge. The payments shall cease effective when the Participant is first eligible to receive reduced old-age insurance benefits under title II of the Social Security Act. The payments shall not be subject to the Post-retirement Survivor Annuity provisions of Article V and shall not be subject to the pension payment adjustment provisions of 3.4(e). Notwithstanding the foregoing provisions of this paragraph, if a Participant who is otherwise entitled to a monthly payment under this paragraph fails to submit to the Employer by December 15, 1993, a completed and signed Social Security Administration Request for Earnings and Benefit Estimate Statement, then the amount of such payment shall be $200.

Except as otherwise provided in the preceding paragraph, the amount of pension payments for Participants entitled to an enhanced benefit under this C-9 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. A Participant who commences Early Retirement under this C-9, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-10 Pre-1994 Disability Retirement—This Appendix C-10 applies to Participants who became a Disabled Participant prior to January 1, 1994. Benefits under the Plan for Participants who became Disabled Participants on or after January 1, 1994 are determined in accordance with the provisions of the Plan except this Appendix C-10. All defined terms used in this C-10 that are not separately defined in this C-10 have the meaning set forth in Appendix A.

Types of Retirement:

Disabled Participants—A Disabled Participant who is eligible for Early Retirement on or before his/her Severance From Service Date, may elect Early Retirement if certain requirements are satisfied. To be eligible to elect Early Retirement, such Disabled Participant must retire either (i) during the period that is within one year following both classification as a Disabled Participant and a reduction in the amount of benefits payable to the Disabled Participant under the Disability Plan due to that plan's offset provisions, or (ii) following termination of the Disability Plan and the failure of the Company to establish a successor plan or policy to provide similar benefits.

Disability Retirement: Generally—A Disabled Participant who is at least age 65 and who, prior to his/her Severance From Service Date, has at least ten years of Credited Service, is eligible for Disability Retirement.

Effective Date—Disability Retirement is effective on the first day of the first month after the Participant reaches age 65.

Early Disability Retirement—A Disabled Participant who, (i) prior to his/her Severance From Service Date, has at least 20 years of Credited Service, and (ii) is at least age 55 but has not yet reached age 65 when he/she is determined to be no longer disabled under the terms of the Disability Plan, is eligible for Early Disability Retirement.

Effective Date—Early Disability Retirement is effective on the first day of the month of retirement designated in writing by the Participant, which is on or after the date that the Participant becomes eligible for Early Disability Retirement, and on or before the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month.

Pension Payments

<u>Disability Retirement</u>—The Gross Pension of a Participant entitled to Disability Retirement is calculated as follows:

Gross Pension =	Disability Retirement Service Percentage	X	Final Average Pay

<u>Early Disability Retirement</u>—The Gross Pension of a Participant entitled to Early Disability Retirement is calculated as follows:

Gross Pension =	Disability Retirement X Service Percentage	Final Average Pay	X	Early Retirement Adjustment Factor

<u>Accrued Gross Pension Calculation and Vesting</u>:

<u>Disability Retirement</u>—A Participant who immediately prior to his/her Benefit Commencement Date is benefiting under the Disability Plan, and who has at least ten years of Credited Service before his/her Severance From Service Date, has a vested right to a Disability Retirement pension on the Participant's Normal Retirement Date.

<u>Early Disability Retirement</u>—A Participant who immediately prior to his/her Benefit Commencement Date is at least age 55 and ceases benefiting under the Disability Plan because he/she is determined to be no longer disabled under the terms of such plan, and who has at least 20 years of Credited Service before his/her Severance From Service Date, has a vested right to an Early Disability Retirement on the Participant's Benefit Commencement Date.

DEFINITIONS

The following definitions apply to the disability benefits under this Plan prior to January 1, 1994:

"Disability Retirement" means a type of retirement available to a Disabled Participant who is at least age 65 prior to his/her Severance From Service Date, and has at least ten years of Credited Service.

"Disability Retirement Service Percentage" means the greater of (i) the percentage equal to (x) the Normal Retirement Service Percentage, less (y) 1/12 of 1 percent for each month that the Participant was less than age 65 on the Participant's Severance From Service Date, or (ii) 30 percent. For purposes of this calculation, the month of the Severance From Service Date is excluded, and the month of the Participant's 65th birthday is included.

"Disabled Participant" means a Participant who is disabled as that term is defined in the Disability Plan.

"Early Disability Retirement" means a type of retirement available to a Disabled Participant who, on the day preceding his/her Severance From Service Date, has at least 20 years of Credited Service, and who is at least age 55 (but not yet age 65) when he/she ceases benefiting under the Disability Plan because he/she is determined to be no longer disabled under the terms of such plan.

C-11 <u>Prior Plan</u>—Except as provided in 1.2 and the last paragraph of 4.3, Participants who do not earn Credited Service on or after January 1, 2000 are covered by the provisions in the Plan in effect before January 1, 2000.

C-12 Accrued Gross Pension Calculation in the Traditional Pension Plan —Prior to January 1, 2000, for each month of Credited Service, a Participant will accrue a portion of the Participant's projected Gross Pension at the Participant's Normal Retirement Date. Subject to the limitations in Appendix B, Section B-2, a Participant's Accrued Gross Pension is calculated as follows:

$$\text{Accrued Gross Pension} = \left(\text{Projected Gross Pension at Normal Retirement Date} - \text{Accrued Gross Pension as of 12/31/75}\right) \times \frac{\text{Credited Service Accumulated To Date After 12/31/75}}{\text{Projected Credited Service Accumulated After 12/31/75 To Normal Retirement Date}} + \text{Accrued Gross Pension as of 12/31/75}$$

In computing the "Projected Gross Pension at Normal Retirement Date," it will be assumed that the Participant will continue to work for the Employer until the Participant's Normal Retirement Date, and that the Participant's Final Average Pay at such date will be equal to the Participant's Average Pay as of the date of the computation. If the Participant works a Part-Time Schedule as of the date of the computation, it will be assumed that the Participant will continue to work a Part-Time Schedule until the Participant's Normal Retirement Date for purposes of the computation.

The “Accrued Gross Pension as of 12/31/75” is equal to the greater of A or B below:

- A -

Accrued Gross Pension as of 12/31/75	=	Projected Gross Pension as of 12/31/75	X	Credited Service Accumulated Prior <u>To 1/1/76</u> Credited Service Projected To Be Accumulated To Normal Retirement Date

2

OR

- B -

Accrued Gross Pension as of 12/31/75	=	0.00125	X	Actual Earnings From 1/1/40 12/31/75	-	Federal Old-Age Benefit Offset

In computing the “Projected Gross Pension as of 12/31/75”, it will be assumed that the Participant will continue to work for the Employer until the Participant’s Normal Retirement Date, and that the Participant’s Final Average Pay at the Participant’s Normal Retirement Date will be equal to the Participant’s Average Pay as of 12/31/75.

<u>Minimum Pension Payment: Generally</u>—Prior to January 1, 2000, if as of the Participant’s Benefit Commencement Date, the Participant’s Gross Pension is less than the Participant’s Accrued Gross Pension reduced in accordance with the adjustments set forth in 3.4(b) and 3.4(c), the Participant’s pension payments will be based on the adjusted Accrued Gross Pension.

C-13 Targeted Voluntary Special Early Retirement Program—Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence are eligible for an enhanced Plan benefit described below, if as of May 31, 2000 they are age 55 or older with at least ten years of Credited Service. The conditions such Participants must meet are as follows: (1) on January 14, 2000, the Participant is an Employee of Baltimore Gas and Electric Company in a job or skill group in the Utility Operations Group (UOG) that has been identified by UOG management for reduction; (2) the Participant receives a written notification from UOG management that his/her job or skill group has been identified for such reduction; (3) the Participant makes an election on or after March 1, 2000 and on or before April 14, 2000 to voluntarily retire on June 1, 2000, and such election shall be irrevocable effective April 14, 2000; (4) the Participant executes (and does not subsequently revoke) in writing and submits to the Plan Administrator, in the form, manner, and subject to the timing established by the Plan Administrator, an agreement releasing legal claims, including those against the Company and its subsidiaries/affiliates, including but not limited to claims arising out of his/her employment with the Employer or termination of such employment; and (5) the Participant is not eligible for the Constellation Energy Group, Inc. Severance Plan.

Traditional Pension Plan:

For purposes of this C-13, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under 3.3(b), except that the Early Retirement Adjustment Factor shall be computed as follows:

The Early Retirement Adjustment Factor for Participants in the Traditional Pension Plan with a Benefit Commencement Date that is on or after the date that the

Participant attains age 60, is 100 percent. For Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 55 but before the date that the Participant attains age 60, the Early Retirement Adjustment Factor is 100 percent less 1/4 of one percent for each month that the Participant is less than age 60 on the Participant's Benefit Commencement Date; provided, however, that for a Participant with at least 35 years of Credited Service as of his/her Severance From Service Date, the Early Retirement Adjustment Factor is 100 percent less 1/4 of one percent for each month that the Participant is less than age 57 on the Participant's Benefit Commencement Date. For purposes of this calculation, the month of the Participant's 55th, 57th and 60th birthdays, as appropriate, is excluded.

PEP:

For purposes of this C-13, the enhanced benefit for eligible PEP Participants is determined as follows:

The Gross Pension referenced in 3.3(e), 3.3(f) and 3.3(g) shall be adjusted by computing Total Pension Credits assuming that on the Participant's Employment Commencement Date (or, if applicable, Adjusted Employment Commencement Date) and thereafter, the Participant's age is the Participant's actual age plus five years.

Social Security Bridge:

In addition, the enhanced benefit for eligible Participants who have not attained age 62 as of June 1, 2000 will include an additional monthly payment equal to one-half of the Participant's estimated monthly age 62 Social Security benefits computed assuming no earnings after 1999. The amount of such estimated age 62 Social Security benefits shall be requested from the Social Security Administration by the Participant and furnished by the Participant to the Company and shall be final and not subject to challenge. The payments shall commence as of the Participant's Benefit Commencement Date and shall cease effective at the earlier of (i) when the Participant is first eligible to receive reduced old-age insurance benefits under title II of the Social Security Act, or (ii) upon the Participant's death. The payments shall not be subject to the Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit provisions of Article V.

Notwithstanding the foregoing provisions, if a Participant who is otherwise entitled to a monthly Social Security bridge payment fails to submit to the Employer by May 31, 2000, an original Social Security Administration Benefit Statement, then the amount of such monthly payment shall be $200.

If a PEP Participant elects a lump sum form of payment pursuant to 3.3(e) of the Plan, then the Social Security bridge payment will be payable in a lump sum as of the Benefit Commencement Date. The lump sum will equal the present value of the additional monthly Social Security bridge payments the Participant would otherwise receive. Such present value shall be calculated based on the mortality table and interest rate described in Present Value as of the Benefit Commencement Date.

Generally:

Except as otherwise provided above, the amount of pension payments for Participants entitled to an enhanced benefit under this C-13 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. A Participant who commences payments under this C-13, and who is subsequently reemployed by the Employer will cease to receive such payments and will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-14 Voluntary Special Early Retirement Program—Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence, who under the terms of the Plan are eligible to commence Early Retirement as of February 1, 2002, and who voluntarily elect to commence Early Retirement on February 1, 2002 (or such later date on or before July 1, 2002 as required in the sole discretion of management of the Employer) shall be entitled to an enhanced benefit. Applicable Participants are Employees of the following Employers: Baltimore Gas and Electric Company (BGE), Constellation Energy Group, Inc. (excluding Employees above the Co-President level), Constellation Energy Source, Inc., Constellation Investments, Inc., Constellation Nuclear, LLC (CN) (excluding Employees above the Vice-President level), Constellation Nuclear Services, Inc. (CNS), Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP), Constellation Power, Inc., Constellation Power Source, Inc., Constellation Power Source Generation, Inc. (CPSG), and Constellation Power Source Holdings, Inc. (collectively, the Companies). The conditions such Participants must meet are as follows: (1) the Participant on November 1, 2001 is an active employee of one of the Companies; (2) the Participant makes an election on or after: (a) November 1, 2001 and on or before December 16, 2001 for CPSG; (b) November 15 and on or before December 31, 2001 for CN, CNS and CCNPP; and (c) November 26, 2001 and on or before December 31, 2001 for the remainder of the Companies, to voluntarily retire on February 1, 2001, and such election shall be irrevocable effective December 16, 2001 for CPSG, and December 31, 2001 for the rest of the Companies; (3) the Participant executes (and does not subsequently revoke) in writing and submits to the Plan Administrator, in the form, manner, and subject to the timing established by the Plan Administrator, an agreement releasing legal claims, including those against the Company and its subsidiaries/affiliates, including but not limited to claims arising out of his/her employment with the Employer or termination of such employment; and (4) the Participant is not eligible for the Constellation Energy Group, Inc. Severance Plan or any other Employer severance plan or arrangement. In addition, Participants who are employees of BGE, CN, CNS, CCNPP or CPSG, and who are involuntarily displaced in connection with a workforce reduction between December 17, 2001 for CPSG (January 2, 2002 for BGE, CN, CNS and CCNPP) and January 31, 2002 (February 28, 2002 for BGE), and who otherwise satisfy all of the foregoing requirements and conditions (except under 2(a) above, December 16, 2001 is replaced with January 31, 2002, and under 2(b) above, December 31, 2001 is replaced with February 28, 2002, and under 2(c) above, December 16, 2001 and December 31, 2001 are replaced with February 28, 2002), are also entitled to an enhanced benefit. Participants who satisfy the requirements and conditions set forth in the preceding sentences shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations.

For purposes of this C-14, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under the Plan, except that (1) the Participant's regular unenhanced Gross Pension shall be computed using average base rate of pay computed as of February 1, 2002 or if later, the Participant's Severance From Service Date, whichever produces the highest amount, and using bonus and/or incentives (i) for purposes of determining Average Pay, that were earned (rather than paid) during the calendar years (a) 1999 and 2000 (including Annual Incentive Awards earned during such years) , or (b) for Participants retiring after March, 2002, if higher, 2000 and 2001 (including Annual Incentive Awards earned during such years); and (ii) for purposes of determining Average Annual Pay, in accordance with the Plan provisions except that Annual Incentive Awards paid during all applicable prior years shall be included; and (2) the Participant shall also be entitled to an additional Gross Pension amount under the Plan, computed as an immediate lump sum equal to: (a) the number of whole years of Credited Service (*i.e.*, partial years of Credited Service are disregarded) multiplied by three, and (b) multiply the product in (a) by the sum of (i) the base rate of pay on the Participant's Severance From Service Date determined as a weekly amount, plus (ii) bonuses and/or incentives (that have previously been approved in writing by the Administrative Committee and the Chairman of the Board of Directors for inclusion in the computation of Average Annual Pay) that were earned during calendar years 1999 and 2000 (including Annual Incentive Awards earned during such calendar years), divided by 104.

Such immediate lump sum amount shall also be available as an immediate annuity using the same formula set forth under Section 3.3(f) of the Plan or as a deferred annuity using the same formula set forth under Section 3.3(g) of the Plan; provided, however, that any Participant in PEP who elects an immediate lump sum must make such election for his/her entire Gross Pension.

Except as otherwise provided above, the amount of pension payments for Participants entitled to an enhanced benefit under this C-14 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. The enhanced benefit does not accrue until the Participant makes an irrevocable election to retire under the program; therefore, preretirement survivor annuity coverage is not available with respect to such enhanced benefit prior to such election. A Participant who commences payments under this C-14, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-15 Voluntary Special Early Retirement Program—Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence are eligible for Early Retirement if, between January 31, 2002 and February 28, 2002, they satisfy the requirements of Section 2.2 after substituting age 50 for age 55, and voluntarily elect to commence Early Retirement on March 1, 2002 (or such later date on or before July 1, 2002 as required in the sole discretion of Baltimore Gas and Electric Company (BGE) or Constellation Power Source Generation, Inc. (CPSG) management) shall be entitled to an enhanced benefit. The conditions such Participants must meet are as follows: (1) the Participant on January 2, 2002 is an employee of BGE (excluding manager- or executive-level employees) or CPSG; (2) the Participant is at least age 50 and no older than age 54 with 20 or more years of service between January 31, 2002 and February 28, 2002; (3) the Participant makes an election on or after January 2, 2002 and on or before February 15, 2002 to voluntarily retire on March 1, 2002, and such election shall be irrevocable effective February 15, 2002; (4) the Participant executes (and does not subsequently revoke) in writing and submits to the Plan Administrator, in the form, manner, and subject to the timing established by the Plan Administrator, an agreement releasing legal claims, including those against the Company and its subsidiaries/affiliates, including but not limited to claims arising out of his/her employment with the Employer or termination of such employment; and (5) the Participant is not eligible for the Constellation Energy Group, Inc. Severance Plan or any other Employer severance plan or arrangement. In addition, Participants who are employees of CPSG, BGE, Constellation Energy Group, Inc., Constellation Investments, Inc., Constellation Power, Inc., Constellation Power Source, Inc., or Constellation Power Source Holdings, Inc., and who are involuntarily displaced in connection with a workforce reduction between January 2, 2002 and February 28, 2002, and who otherwise satisfy all of the foregoing requirements and conditions (except under (3) above, February 15, 2002 is replaced with February 28, 2002), are also entitled to an enhanced benefit. Participants who satisfy the requirements and conditions set forth in the preceding sentences shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations.

For purposes of this C-15, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under the Plan, except that (1) the Participant's regular unenhanced Gross Pension shall be computed using average base rate of pay computed as of March 1, 2002 or if later, the Participant's Severance From Service Date, whichever produces the highest amount, and using bonus and/or incentives (i) for purposes of determining Average Pay, that were earned (rather than paid) during the calendar years (a) 1999 and 2000 (including Annual Incentive Awards earned during such years), or (b) for Participants retiring after March 2002, if higher, 2000 and 2001 (including Annual Incentive Awards earned during such years); and (ii) for purposes of determining Average Annual Pay, in accordance with the Plan provisions except that Annual Incentive Awards paid during all applicable prior years shall be included; and (2) the Participant shall also be entitled to an additional Gross Pension amount under the Plan, computed as an immediate lump sum equal to: (a) the number of whole years of Credited Service (*i.e.*, partial years of Credited Service are disregarded) multiplied by two, and (b) multiply the product in (a) by the sum of (i) the base rate of pay on the Participant's Severance From Service Date determined as a weekly amount, plus (ii) bonuses and/or incentives (that have previously been approved in writing by the Administrative Committee and the Chairman of the Board of Directors for inclusion in the computation of Average Annual Pay) that were earned during calendar years 1999 and 2000 (including Annual Incentive Awards earned during such calendar years), divided by 104.

Such immediate lump sum amount shall also be available as an immediate annuity using the same formula set forth under Section 3.3(f) of the Plan or as a deferred annuity using the same formula set forth under Section 3.3(g) of the Plan; provided, however, that any Participant in PEP who elects an immediate lump sum must make such election for his/her entire Gross Pension. The enhanced benefit for applicable participants shall also be computed by substituting age 50 for age 55 in Section A-20.

Except as otherwise provided above, the amount of pension payments for Participants entitled to an enhanced benefit and under this C-15 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. The enhanced benefit does not accrue until the Participant makes an irrevocable election to retire under the program; therefore, preretirement survivor annuity coverage is not available with respect to such enhanced benefit prior to such election. A Participant who commences payments under this C-15, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

APPENDIX D

TOP HEAVY PROVISIONS

D-1 Purpose—If the Plan is or becomes top-heavy in any Plan Year beginning after December 31, 1983, the following provisions will supersede any conflicting provisions in the Plan.

D-2 Definitions—As used in the Plan, the following terms shall have the meaning set forth below, unless a different meaning is clearly required by the context in which the term is used.

D-2.2 "Anniversary Date" means December 31, the last day of the Plan Year.

D-2.4 "Key Employee" means any person who meets the requirements of Code Section 416(i), and the regulations promulgated thereunder, which are hereby incorporated by reference as if fully set out herein. For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term Key Employee shall also include the beneficiary of a Key Employee.

D-2.5 "Permissive Aggregation Group" means all plans in the Required Aggregation Group and any other Qualified Plans maintained by the Company, but only if such group of plans would satisfy, in the aggregate, the requirements of Code Sections 401(a)(4) and 410. The Plan Administrator shall determine which plan or plans shall be taken into account in determining the Permissive Aggregation Group.

D-2.6 "Qualified Plan" means any Plan which is qualified under Code Section 401(a).

D-2.7 "Required Aggregation Group" means:

(a) Each Qualified Plan of the Company in which at least one Key Employee participates; and

(b) Any other Qualified Plan of the Company which enables a Plan described in Section D-2.7(a) to meet the requirements of Code Section 401(a)(4) or 410.

D-2.8 "Top-Heavy Plan" means the Plan, for any Plan Year in which the Plan meets the requirements of Section D-3.2.

D-3 Top-Heavy Plan Requirements and Determination

D-3.1 Top Heavy Plan Requirements—For any Plan Year in which the Plan is determined to be a Top-Heavy Plan in accordance with Section D-3.2, the Plan shall be subject to the following:

(a) special vesting requirements in D-4; and

(b) special minimum benefit requirements of D-4.

D-3.2 Top-Heavy Plan Determination

(a) The Plan shall be considered a Top-Heavy Plan and shall be subject to the additional requirements of Section D-3.1, with respect to any Plan Year, if, as of the Anniversary Date of the preceding Plan Year (hereinafter referred to as the "determination date"), (i) the present value of accrued benefits of Key Employees in this Plan exceeds 60 percent of the present value of the accrued benefits of all Employees in this Plan ("60% Test"); or (ii) the Plan is part of a Required Aggregation Group and the sum of the present value of accrued benefits and the value of the aggregate accounts of Key Employees in all plans in the Required Aggregation Group exceeds 60% of a similar sum for all Employees. For this purpose, the present value of accrued benefits and the value of the aggregate accounts shall be determined as of the valuation date for the Plan Year that includes the determination date.

(b) For purposes of this Section D-3.2, the aggregate account of a Participant is determined under applicable provisions of the defined contribution plan used in determining whether the Plan is a Top Heavy Plan.

(c) For purposes of this Section D-3.2, present value of accrued benefits shall be determined, in the case of a defined benefit pension plan, under the provisions of such a plan or plans and shall include any part of any accrued benefit distributed in the 5-year period ending on the determination date. Effective January 1, 2002, the present value of accrued benefits shall include any part of any accrued benefit distributed in the 1-year period ending on the determination date, or, in the case of a distribution made for a reason other than severance from employment, death or disability, during the 5-year period ending on the determination date.

(d) For purposes of this Section D-3.2, the present value of a participant's accrued benefits under a defined benefit plan shall be based upon reasonable interest and mortality assumptions specified by the plan. The Top-Heavy calculations for this Plan shall be based on the same assumptions specified in the definition of Present Value in Section A-44. Where one or more defined benefit plans are aggregated with this Plan for purposes of Top-Heavy calculations, the actuarial assumptions specified in the definition of Present Value in Section A-44 shall be applied to all plans in the aggregation group.

(e) For purposes of this Section D-3.2, the accrued benefit of a participant who is not a Key Employee shall be determined under the method, if any, that uniformly applies for determining benefit accruals under all defined benefit plans maintained by the Employer, or if there is no such method, as if the benefit accrued not more rapidly than the slowest accrual rate permitted under the fractional accrual rule of Section 411(b)(1)(C) of the Code.

(f) For purposes of this Section D-3.2, the accrued benefit of a participant in a plan who is not a Key Employee but who was a Key Employee in a prior year shall be disregarded.

(g) For purposes of this Section D-3.2, the accrued benefits of all plan participants who have not performed services for any employer maintaining the plan at any time during the 5-year period (1-year period, effective January 1, 2002) ending on the determination date shall be disregarded.

(h) Notwithstanding the provisions of subsection (a) herein above, the Plan shall not be a Top-Heavy Plan, if the Plan Administrator elects to treat the Plan as part of a Permissive Aggregation Group, and the Permissive Aggregation Group is not determined to be Top-Heavy using the criteria of the "60% Test" herein above.

(i) Where more than one plan is involved in the determination, only determination dates that fall within the same calendar year shall be considered in order to determine whether the Plan is a Top-Heavy Plan.

(j) The provisions of Code section 416 and applicable regulations are incorporated with respect to any additional requirements with respect to the determination as to how the top heavy ratio is computed.

D-4 Additional Top-Heavy Provisions—For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term "Participant" as defined in Appendix A, shall also include the beneficiary of a Participant.

Notwithstanding any other provisions of the Plan if the Plan is a Top-Heavy Plan:

(i) Each Participant who has at least three years of Vesting Service as of the determination date will be fully vested in a pension benefit on the day following the determination date. Each Participant who subsequently accumulates at least three years of Vesting Service shall immediately be fully vested in such pension benefit.

(ii) Each Participant who is not a Key Employee will be deemed to have an Gross Pension after the determination date equal to 1/12 of the lesser of (A) 20% of such Participant's average compensation or (B) such average compensation multiplied by 2% for each year of Credited Service accumulated to the date of the calculation. For purposes of this calculation, average compensation is the Participant's highest average compensation for the five consecutive years for which the Participant had the highest compensation. For purposes of this paragraph, compensation means Section 415(c) Compensation. Effective January 1, 2002, in determining service for purposes of this minimum benefit calculation, any service shall be disregarded to the extent that such service occurs during a plan year when the Plan benefits (within the meaning of Code section 410(b)) no Key Employee or former Key Employee.

APPENDIX G

DESIGNATED SUBSIDIARIES

Except as otherwise provided below, Employees of the following subsidiaries are eligible to participate in the Plan on the same terms and conditions as set forth therein.

Constellation Power, Inc.

Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.) Constellation Power Source Generation, Inc.

Constellation Energy Source, Inc.

BGE Home Products and Services, LLC (formerly known as BGE Home Products and Services, Inc.) [1]

BGE Commercial Building Systems, Inc. [2]

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1 a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Home Products & Services, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. Notwithstanding the preceding sentence, an individual who is an Employee of Constellation Energy Source, Inc. on December 31, 1999, who transfers to BGE Home Products & Services, Inc. effective January 1, 2000, and was hired by Constellation Energy Source, Inc. after December 31, 1994, shall participate in PEP as modified in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Home Products & Services, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Home Products & Services, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e); 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Home Products & Services, Inc. This (ii) is not applicable to a Participant who received benefits under the Special Window for Employees Employed by BGE Home (as part of BGE Home's closing of its retail appliance and merchandise stores and the reorganization of BGE Home because of that closing) under the Constellation Energy Group, Inc. Severance Plan.

(iii) The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iv) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Home Products & Services, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

2 a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Commercial Building Systems, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding sentence will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Commercial Building Systems, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Commercial Building Systems, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e). 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Commercial Building Systems, Inc. The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iii) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Commercial Building Systems, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

Baltimore Gas and Electric Company [3]

Constellation Nuclear Services, Inc.

Constellation Generation Group, LLC

Constellation Operating Services, Inc.; Constellation Operating Services; COSI Central Wayne, Inc. (Employees represented by a union under a collective bargaining agreement are not eligible to participate); COSI Synfuels, Inc.; COSI Sunnyside, Inc.; COSI Puna, Inc.; PCI Operating Company Partnership [4]

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3 With respect to an Employee of the Comfort Link division of Baltimore Gas and Electric Company, only individuals who are both a Participant on December 31, 1999 and an Employee of the Comfort Link division of Baltimore Gas and Electric Company on January 1, 2000, shall be eligible to participate in the Plan. Notwithstanding anything in the Plan to the contrary, the Vice-Chairman of Baltimore Gas and Electric Company will not be eligible to participate in this Plan.

4 Employees of each listed subsidiary are eligible for participation in PEP effective January 1, 2003.
For purposes of 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which an Employee first performed an hour of service for the subsidiary. However, if the Participant was an Employee on January 1, 2003 and was employed by one of the following entities on the day immediately preceding the date the Employee became employed by the subsidiary, by A/C Power or by Trona Operating Partners, G.P. (or one of their subsidiaries), the Employment Commencement Date shall be the date on which the Employee first performed an hour of service for such entity (but in no event prior to any date noted in parentheses below):

Malacha Power Project, Inc.
Sunnyside Operating Associates
Niagara Mohawk Power Corporation
Consolidated Edison Company of New York (but only if the Employee was hired by COSI Astoria after August 20, 1999)
OESI Power (but only if the Employee was transferred to Constellation Operating Services, Inc. or one of its subsidiaries from OESI Power on January 6, 1993)
Kerr McGee Corporation—(but only if the Employee became an employee of Constellation Operating Services, Inc., A/C Power, or Trona Operating Partners, G.P. on December 1, 1990)
Ahlstrom Pyropower (or any other employer wholly or partially owned directly or indirectly, by
Ahlstrom Pyropower (or any successor thereto))
Ultrasystems, Inc.
Hadson Corporation
LG&E Power, Inc
LUZ International
U C Operating Services
Panther Creek Fuels Company
Nevada Operations, Inc.
Central Wayne County Sanitation Authority
U. S. Generating (COSI Carr Street)
Ormat Energy Systems, Inc.
Ormat Systems, Inc.
Baltimore Gas and Electric Company (or any other employer wholly or partially owned directly or indirectly, by Baltimore Gas and Electric Company (or any successor thereto))
A/C Power

For purposes of 2.1 and A-31, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Normal Retirement.

For purposes of 2.2 and A-19, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Early Retirement.

For purposes of 4.3, Credited Service shall only include months beginning on or after January 1, 2003 during which an Employee works at least one hour for the Employer while classified as a Full-Time Employee.

Constellation NewEnergy, Inc. (Note: Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.)

CNE Gas Holdings, Inc. (Note: Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.)

APPENDIX I

BONUSES, INCENTIVE AND OTHER PAY

Part 1

The following types of license and other special bonuses are included in the base rate of pay definition of Average Annual Pay (set forth in Section A-8(i)) or Average Pay (set forth in Section A-9(i)), as applicable.

- NRC License Bonus
- Electrician License Bonus
- Plumber License Bonus

Part 2

The following types of bonuses and/or incentives are included in the bonuses and incentives definition of Average Annual Pay (set forth in Section A-8(ii))or Average Pay (set forth in Section A-9(ii)), as applicable.

Baltimore Gas and Electric Company

- Promotion Recognition Award
- Results Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

BGE Home Products & Services, Inc.

- Commission payments (includes draw payments, administrative time, vacation time, non-selling time, and training time payments)
- Sales Incentive Award
- Results Incentive Award
- Scale Rate Payment
- Piece Work Payment
- Emergency Work Payment
- Sales Bonus
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Calvert Cliffs Nuclear Power Plant, Inc.

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

CER Generation, LLC

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

CNE Gas Holdings, Inc. *

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Building Systems, Inc.

- Commission Payments (includes draw payments, administrative time, vacation time, non-selling time, and training time payments)
- Results Incentive Award
- Scale Rate Payment
- Piece Work Payment
- Emergency Work Payment
- Sales Bonus
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.) *

- Results Incentive Award
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Group, Inc.

- Promotion Recognition Award
- Results Incentive Award
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Nuclear Group

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

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* For Employees of this subsidiary who were Participants in the Plan on or before March 31, 2011, bonuses and/or incentives included in Average Annual Pay or Average Pay as applicable, shall be capped at $200,000 beginning with bonuses paid on or after April 1, 2011. For Employees of this subsidiary who became participants in the Plan on or after April 1, 2011, bonuses and/or incentives included in Average Annual Pay shall be capped at $200,000 beginning with bonuses paid on or after January 1, 2007.

Constellation Energy Projects & Services Group, Inc.

- Annual Incentive Award (includes Sales Bonuses paid to Participants employed as Business Developers, Major Account Executives, and Senior Account Executives. The Sales Bonus maximum percentage equals 30% of the eligible Participant's annual base pay.)
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Projects & Services Group Advisors, LLC *

- Annual Incentive Award (includes Sales Bonuses paid to Participants employed as Business Developers, Major Account Executives, and Senior Account Executives. The Sales Bonus maximum percentage equals 30% of the eligible Participant's annual base pay.)
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation NewEnergy, Inc.*

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Sales Bonus
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Nuclear Services, Inc.

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Contract Incentive Rate Award
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Operating Services

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

Constellation Power, Inc.

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

Constellation Power Source Generation, Inc.

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Power Source Holdings, Inc.

- Annual Incentive Award
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Real Estate, Inc.

- Annual Incentive Award

COSI Sunnyside, Inc.

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

Exhibit 10.65

FIRST AMENDMENT TO THE
PENSION PLAN OF
CONSTELLATION ENERGY GROUP, INC.
(Amended and Restated Effective January 31, 2012)

WHEREAS, Constellation Energy Group, Inc. (the "Company") sponsors the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective as of January 31, 2012) (the "Plan"), which is intended to meet the requirements of the provisions of the Internal Revenue Code of 1986, (as amended) (the "Code"); and

WHEREAS, the Company intended to provide all employees who are eligible for severance benefits on or after June 1, 2003, under its Company-sponsored severance plan pension benefits based on their age and years of service at the end of their severance period, as set forth in Section 3.5 of the Plan; and;

WHEREAS, a new severance plan was established on September 19, 2008; and

WHEREAS, the Plan Administrator of the Plan, pursuant to the authority granted to her in Section 6.6(b) of the Plan, has consistently interpreted Section 3.5 to apply to participants eligible for severance under the new severance plan even though it wasn't specifically referenced in the Plan; and

WHEREAS, pursuant to Section 9.1, the Chief Human Resources Officer may amend the Plan in ways that do not materially affect liabilities; and

WHEREAS, an actuarial determination has been made that the cost of providing such benefits to participants in the new severance plan is immaterial;

NOW, THEREFORE, BE IT RESOLVED, that for purposes of clarity, the Plan is hereby amended as follows, effective September 19, 2008, except where noted:

1. By amending Section 3.5, Severance Plan Payments, to delete the phrase “Constellation Energy Group, Inc. Severance Plan” each time it occurs, and to insert in its place the term, “Severance Plan”.

2. By replacing section A-46 Deleted with the following:

   A-46 “Severance Plan” shall mean either of the Constellation Energy Group, Inc. Severance Plan or the Constellation Energy Group, Inc. Severance Plan for Constellation Energy Resources, LLC and Other Employees.

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IN WITNESS WHEREOF, this Amendment to the Plan was executed on this _____ day of March, 2012.

____

Mary L. Lauria
Chief Human Resources Officer

Exhibit 10.66

**SECOND AMENDMENT TO THE
PENSION PLAN OF
CONSTELLATION ENERGY GROUP, INC.
(Amended and Restated Effective January 31, 2012)**

WHEREAS, .Exelon Corporation (the "Company") sponsors the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012) (the "Plan"); and

WHEREAS, the Company desires to amend the Plan to incorporate the provisions of a special lump sum payment option and to reflect changes necessary to comply with Section 436 of the Internal Revenue Code of 1986, as amended, and the final regulations thereunder.

NOW, THEREFORE, RESOLVED, that pursuant to the power of amendment contained in Article IX of the Plan, the Plan is amended, effective October 1, 2012, except as otherwise stated below:

1. Effective on and after January 1, 2013, Section 1.1 of the Plan is amended by inserting the following at the end thereof:

No Employee hired on or after January 1, 2013 shall be eligible to participate in the Plan, with the exception of Employees of the Employer listed on Appendix G.

2. Effective on and after the Effective Time, Article 1 of the Plan is amended by inserting the following new Section 1.3 at the end thereof:

1.3 Effect of Merger Agreement — If an Employee who was an Employee on or prior to the Effective Time transfers employment to or is reemployed by Exelon in a job classification with respect to which similarly situated employees of Exelon are not eligible to participate in the Plan but are instead eligible to participate in a Parent Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be qualified under Section 401(a) or 401(k) of the Code (each such plan, an "Exelon Retirement Plan"), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Exelon Retirement Plan. If a participant in an Exelon Retirement Plan who was a participant in such plan on or prior to the

Effective Time transfers employment to or is reemployed by a Participating Employer in a job classification with respect to which similarly situated employees of such Participating Employer are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the Exelon Retirement Plan and shall not participate in the Plan.

3. Article I of the Plan is amended by inserting the following new Section 1.4 at the end thereof:

Section 1.4. Certain Rehired Employees. Notwithstanding anything contained herein to the contrary, no individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 3.6 shall be eligible to become a Participant pursuant to this Article 1.

4. Article III of the Plan is amended by adding the following new Section 3.6 at the end thereof:

Section 3.6. Special Lump Sum Payment Option. (a) Eligibility. A Participant may elect to receive, during the election period described in this Section 3.6, his or her deferred Gross Pension as a terminated vested participant under the Plan ("Deferred Gross Pension") in the form of a lump sum payment ("Special Lump Sum Payment") or, an "Immediately Commencing Annuity" (as defined below); provided, however, that:

(i) the Participant has a Severance From Service Date prior to June 30, 2012 and does not die and is not rehired during the period beginning July 1, 2012 and ending on the date payment is made or commences in accordance with this Section 3.6;

(ii) the Participant has not otherwise commenced receiving pension benefits under the Plan on or prior to the date payment is made or commences in accordance with this Section 3.6;

(iii) such Severance From Service Date is not on account of the Participant's disability, following which the Participant is receiving long-term disability payments under any long-term disability program of an Employer, including on June 30, 2012;

(iv) the Participant's Deferred Gross Pension is not subject to a qualified domestic relations order as defined in Section 414(p) of the Code

(v) the Participant is not immediately, as of his or her Severance From Service Date, eligible for early retirement benefits in accordance with 3.3(b) above;

(vi) the Participant is not on a leave of absence or layoff from an Employer on June 30, 2012;

(vii) the Participant is not 70 ½ years of age or older as of October 1, 2012; and

(viii) the Participant can be located, after a diligent search, as necessary, by the Plan Administrator before July 1, 2012.

For each such Participant described in this paragraph (a) of this Section 3.6, the term "Immediately Commencing Annuity" shall mean, as applicable, either:

(i) with respect to a Participant eligible to commence receipt of his or her Deferred Gross Pension as of December 1, 2012, any applicable optional form of annuity available to the Participant under this Article III; or

(ii) with respect to any other Participant, a single life annuity, 50% "qualified joint and survivor annuity" (within the meaning of Code Section 417(b)) or a 75% "qualified optional survivor annuity" (within the meaning of Code Section 417(g)).

For purposes of this Section 3.6, a "Participant" shall also include a beneficiary of a Participant who otherwise satisfies the requirements of this Section 3.6 but for the Participant's death prior to July 1, 2012.

3.6(b) Election and Election Period. To receive the distribution of benefits described in paragraph (a) of this Section 3.6, an eligible Participant must voluntarily elect to receive a distribution pursuant to this Section 3.6 by completing an election form and spousal waiver, if required, provided by the Administrator, and submitting such forms to the Administrator after October 1, 2012 and before the following dates, as applicable,

(i) November 15, 2012, with respect to a Participant who elects a Special Lump Sum Payment; and

(iii) December 15, 2012, with respect to a Participant who elects an Immediately Commencing Annuity,

or such other period during 2012 determined by the Administrator.

The Administrator shall provide each eligible Participant, not less than 30 days and not more than 180 days before the Benefit Commencement Date, an application form including a general description of the material features, as well as an explanation of the relative values and financial effect, of the optional forms of benefit available under this Section 3.6, in a manner that satisfies the notice requirements of Section 417(a)(3) of the Code and the Treasury Regulations thereunder. The form shall indicate the Participant's right to waive a survivor annuity, his Surviving Spouse's right to consent to such waiver or refuse such consent, and the right to revoke any waiver, within the 180 day period preceding the Benefit Commencement Date, and shall include a description of the right of the Participant, if any, to defer receipt of a distribution and the consequences of failure to defer such receipt, in accordance with Treasury guidance under Section 411(a)(11) of the Code.

3.6(c) Amount of Payment. The Special Lump Sum Payment shall equal the actuarial equivalent of the Participant's nonforfeitable Deferred Gross Pension, based on the following factors:

(i) the applicable interest rate described in Section 417(e)(3) of the Code for August of 2011;

(ii) an assumed commencement date of the later of (A) age 65, and (B) the Participant's age as of December 1, 2012;

(iii) the applicable mortality table, as defined in Section 417 of the Code and the Treasury Regulations promulgated thereunder; and

(iv) the Gross Pension of a Participant in the PEP shall be calculated, in accordance with the terms of the existing terms of the Plan, as the present value of the age 65 deferred annuity (within the meaning of 3.3(g)).

The Immediately Commencing Annuity shall be calculated:

(i) in accordance with the applicable terms of the Plan, for a Participant who is eligible to immediately commence benefits under the terms of the Plan as of the payment date set forth in paragraph (d) of this Section 3.6 and

(ii) as the actuarial equivalent of the Special Lump Sum Payment, for each other Participant.

3.6(d) Payment of Benefit. If an eligible Participant elects the distribution of his or her Deferred Gross Pension in accordance with this Section 3.6, payment shall be made, or commence to be made, on or before December 1, 2012, or as soon as administratively practicable thereafter.

3.6(e) Death and Rehire. If an eligible Participant elects the distribution of his or her Deferred Gross Pension in accordance with this Section 3.6 and subsequently dies or is rehired as an Employee before distributions commence, his or her election shall be null and void and the Participant's benefit shall be paid pursuant to the Plan without regard to this Section 3.6. Notwithstanding anything contained herein to the contrary, upon distribution of a Special Lump Sum Payment or an Immediately Commencing Annuity made to an individual in accordance with this Section 3.6, in the event of the individual's rehire with an Employer following the date such distribution is made, the individual shall not be eligible to participate in the Plan during such period of rehire and may be eligible to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees (or such other plan that applies to employees of an Employer hired on or after December 1, 2012), as applicable, in accordance with their terms and conditions.

5. Effective on and after the Effective Time, Section 6.1 shall be amended by adding a sentence before the first sentence, as follows:

Each person entitled to a payment under the Plan shall furnish such information and data, including birth certificates or other evidence of age satisfactory to the Administrator, and sign such documents as may reasonably be requested by the Administrator or the Trustee in connection with the administration of the Plan.

6. Effective on and after the Effective Time, Sections 6.4, 6.5, 6.6, 6.7 and 6.8 shall be deleted in their entirety, and new Sections 6.4 through 6.12 shall be added as follows, and the remaining sections shall be renumbered:

6.4 The Administrator, the Investment Fiduciary and the Corporate Investment Committee

6.4(a) The Administrator — The Company's Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan.

The determination of the Administrator with respect to an Employee's years of Vesting Service, the amount of the Employee's Compensation, and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his or her discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his or her duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust Fund under Article 7 (relating to distributions). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Participants, the amounts of all Pensions, the dates of death of Participants and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Pension to be paid out of the Trust Fund.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Fiduciary, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

6.4(b) Removal of Administrator — The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

6.4(c) The Investment Fiduciary — The Company, acting through the Exelon Investment Office, shall be the Investment Fiduciary and the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in section 404(a)(2) of ERISA and all other applicable limitations. The Investment Fiduciary shall have the following duties, responsibilities and rights:

(i) The Investment Fiduciary shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Trust Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Fiduciary shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Fiduciary.

(iii) Each Employer shall, from time to time, upon request of the Investment Fiduciary, furnish to the Investment Fiduciary such data and information as the Investment Fiduciary shall require in the performance of its duties.

6.4(d) The Corporate Investment Committee — The Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Fiduciary. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Fiduciary and shall review annual manager review results and any other reports and documents submitted by the Investment Fiduciary.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Fiduciary, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Fiduciary.

(iii) The Corporate Investment Committee shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Fiduciary. Any successor Investment Fiduciary shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the Investment Fiduciary and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

6.4(e) Status of Administrator, the Investment Fiduciary and the Corporate Investment Committee — The Administrator, any person acting as, or on behalf of, the Investment Fiduciary, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Fiduciary, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Fiduciary on any matter involving solely his or her rights under this Plan.

6.4(f) Notice to Trustee of Members — The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Fiduciary.

6.4(g) Allocation of Responsibilities. Each of the Administrator, the Investment Fiduciary and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

6.4(h) General Governance — Each of the Administrator, the Investment Fiduciary and the Corporate Investment Committee may act at a meeting or by written consent approved by a majority of its respective members, as applicable. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. The secretary of the Corporate Investment Committee shall keep a record of all meetings and forward all necessary communications to the Employers or the Trustee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Fiduciary and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

6.4(i) Indemnification — The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

6.4(j) No Compensation. None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Fiduciary or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

6.4(k) Employ of Counsel and Agents. The Administrator, the Investment Fiduciary and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

6.5 Claims Procedure. Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Section 8.9 (relating to statute of limitations for actions under the Plan) and 8.10 (relating to forum for legal actions under the Plan)) to bring a civil action under section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to the officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

6.6 Notices to Participants, Etc. — All written notices, reports and statements given, made, delivered or transmitted to a Participant or Beneficiary or any other person entitled to or claiming benefits under the Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or Beneficiary or such other person at the address last appearing on the records of the Administrator. A Participant or Beneficiary or other person may record any change of his or her address from time to time by written notice filed with the Administrator.

6.7 Responsibility to Advise Administrator of Current Address — Each person entitled to receive a payment under the Plan shall file with the Administrator in writing his or her complete mailing address and each change therein. A check or communication mailed to any person at his or her address on file with the Administrator shall be deemed to have been received by such person for all purposes of the Plan, and neither the Administrator, the Employers nor the Trustee shall be obliged to search for or ascertain the location of any person. If the Administrator shall be in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his or her last address known to the Administrator, notify such person that all future Pension payments will be withheld until such person submits to the Administrator evidence of his or her continued life and his or her proper mailing address.

6.8 Notices to the Firm or Administrator — Written directions, notices and other communications from Participants or Beneficiaries or any other persons entitled to or claiming benefits under the Plan to the Employers or the Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the form prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

6.9 Records. Each of the Administrator, the Investment Fiduciary and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account, records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

6.10 Actuary to be Employed — The Company or the Investment Fiduciary shall engage an actuary to do such technical and advisory work as the Company or the Investment Fiduciary may request, including analyses of the experience of the Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Fiduciary of an annual actuarial report, which report shall contain information showing the financial condition of the Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Fiduciary.

6.11 Electronic Media — Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

6.12 Correction of Error — If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

7. Effective on and after of the Effective Time, Section 7.1 shall be deleted in its entirety, and shall be replaced as follows:

7.1 Contributions and Funding Policy — No contributions from any Participant shall be required or permitted under the Plan. The Company shall establish a funding policy and method consistent with the objectives of the Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Fiduciary. Forfeitures arising under this Plan shall be applied to reduce the expenses of Plan administration, not to increase the benefits otherwise payable to Participants.

8. Effective on and after the Effective Time, Section 8.2(a) shall be amended to delete the third paragraph thereof.

9. Article VIII of the Plan is amended by adding the following new Sections 8.8 at the end thereof:

8.8. Certain Rehired Employees. Notwithstanding anything contained herein to the contrary, an individual who is reemployed by an Employer after December 19, 2012 and has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 3.6 shall not be eligible to become a Participant pursuant to Article 1.

10. Effective on and after the Effective Time, Article VIII of the Plan is amended by adding the following new Sections 8.9, 8.10, 8.11, and 8.12 at the end thereof, as follows:

8.9 Expenses. The expenses of the Trustee in the administration of the Trust Fund, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Trust Fund, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan or the Trust Fund, as applicable, including, but not limited to, "direct expenses" incurred in administering the Plan and the Trust Fund (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust Fund), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Trust Fund, as applicable, shall be paid by the Trustee from the Trust Fund in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Notwithstanding the foregoing, the Administrator or the Investment Office may authorize an Employer to act as an agent of the Plan to pay any expenses, and the Employer shall be reimbursed from the Trust Fund for such payments.

8.10 Statute of Limitations for Actions under the Plan. Except for actions to which the statute of limitations prescribed by section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

8.11 Forum for Legal Actions under the Plan. Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in District of Maryland, and no other federal or state court.

8.12 Legal Fees. Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, any member of the Exelon Investment Office, any member of the Corporate Investment Committee, the Chief Human Resources Officer, any Plan fiduciary, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

11. Effective on and after the Effective Time, Section 9.1 and 9.2 shall be deleted in their entirety, and shall be replaced as follows

9.1 Amendment — The Board of Directors of the Company (or a committee thereof) may at any time and from time to time amend or modify this Plan in any manner deemed by the board of directors of the Company to be necessary or desirable, provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility and, provided further, that no amendment shall be made that is not consistent with any applicable collective bargaining agreement. Any such amendment or modification shall become effective on such date as the Board (or committee thereof) or executive shall determine and may apply to Participants in this Plan at the time thereof as well as to future Participants, provided, however, that, unless permitted by applicable law, no such amendment or modification which reduces the basis for the computation of benefits shall be retroactive as to service prior to the date of such amendment or modification.

9.2 Termination

9.2(a) Termination of the Plan by an Employer. The Company may at any time, by resolution adopted by its board of directors, terminate this Plan in its entirety. In addition, any Employer may at any time terminate its participation in this Plan by resolution adopted by its board of directors to that effect. Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that this Plan and the Trust as adopted by the Company meets the requirements of section 401(a) of the Code and that the Trust is exempt from tax under section 501(a) of the Code, and if the Internal Revenue Service shall refuse to issue such letter, any Employer may terminate its participation in this Plan and direct the Trustee to pay and deliver to that Employer the portion of the Trust applicable to its contributions.

9.2(b) Vesting and Distribution Upon Termination or Partial Termination. Upon termination or partial termination of the Plan, the benefit as of the date of termination or partial termination, as the case may be, of all affected Participants shall be fully vested; provided, however, that full vesting shall be required with respect to a termination or partial termination only to the extent the Plan is then funded.

Allocation and distribution of the terminated portion of the Trust Fund shall thereafter be made in accordance with the applicable requirements of ERISA and the Code and with any applicable approval of the Pension Benefit Guaranty Corporation (the “PBGC”). If the Administrator is notified by PBGC that PBGC is unable to determine that the Trust Fund is sufficient to discharge when due all obligations of the Plan with respect to benefits guaranteed by PBGC pursuant to section 4022 of ERISA, then the allocation and distribution of such portion of the Trust shall be made only under the direction of PBGC or a United States district court pursuant to section 4044 of ERISA.

In the event that, after the termination of the Plan, any assets remain after such allocation, such assets shall be paid to the Company. The portion of the assets allocated to provide benefits to any person or group of persons may be applied for the benefit of such person or persons by the distribution of cash, continuance of the Trust, establishment of a new Trust, purchase of annuities from an insurance company, or otherwise, as determined by the Investment Fiduciary in its sole discretion; provided, however, that the benefit of any Participant or former Participant who is married and has satisfied the vesting requirement shall, unless such person shall elect otherwise, be paid in the form set forth in the Plan relating to manner of distribution with respect to married Participants and, if the surviving Spouse of a deceased Participant or deceased former Participant is entitled to receive a benefit pursuant to the Plan provisions relating to manner of distribution with respect to married Participants or to pre-retirement death benefits, as the case may be, such benefit shall, unless such person shall elect otherwise, be paid in the form set forth therein.

Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that the Plan and Trust Fund as adopted by the Company meet the requirements of section 401(a) of the Code and that the Trust is exempt from tax under section 501(a) of the Code, and, in the event that the Internal Revenue Service shall refuse to issue such letter, the Company may terminate the Plan and shall direct the Trustee to pay and deliver the Trust to the Company.

12. Effective on and after the Effective Time, the text of Appendix A-2 of the Plan is deleted and replaced as follows: “Reserved,” and all references to the “Administrative Committee” shall be deleted.

13c. Effective on and after the Effective Time, Appendix A-13 is amended by replacing the entirety of the text as follows:

A-13 “Company” means Exelon Corporation, and its successor and assigns.

14. Effective on and afterthe Effective Time, Appendix A-16 is amended by replacing the entirety of the text as follows:

A-16 “Disability Plan” means the Constellation Energy Group, Inc. Long-Term Disability Plan, the Exelon Corporation Long Term Disability Plan, or any successor plan.

15. Effective on and after November 30, 2012, Appendix A-20 is amended by adding the following at the end thereof:

For employees who employees who were Transferred Employees as that term is defined in the Purchase and Sale Agreement by and between Constellation Power Source Generation, Inc. as Seller, and Raven Power Holdings LLC as Buyer, dated as of August 8, 2012, Credited Service for purposes of determining the Early Retirement Adjustment Factor shall include all time periods while employed by the Buyer, and dit for age attained during employment with the Buyer until such time as the Transferred Employee elects to receive benefits under the Plan; and (ii)

16. Effective on and after the Effective Time, a new Appendix A-20a shall be added immediately following Appendix A-20 as follows:

A-20a “Effective Time” means the effective time of the transaction that is the subject of the Merger Agreement, as such term is defined in the Merger Agreement.

17. Effective on and after the Effective Time, Appendix A-21 shall be amended by adding a sentence after the first sentence as follows:

> Effective as of the Effective Time, Employee shall not include any person who was: (i) employed immediately prior to the Effective Time at Exelon or a facility owned immediately before the Effective Time by Exelon or (ii) initially employed on or after the Effective Time at a facility owned immediately before the Effective Time by Exelon.

18. Effective on and after the Effective Time, the text of Appendix A-24a is deleted and replaced as follows, and all references to the "Executive Group" shall be deleted.

> A-24a "Exelon" means Exelon Corporation and any of its affiliates that was an affiliate immediately before the Effective Time.

19. Appendix A-21 of the Plan is amended by adding the following new sentence at the end thereof:

> Notwithstanding anything contained herein to the contrary, an Employee shall not include an individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 3.6.

20. Appendix A-29 of the Plan is amended by inserting the following new sentence at the end thereof:

> Notwithstanding the foregoing, a Participant shall not be entitled to any amount payable from the Trust under the Plan following the Participant's receipt of a Special Lump Sum Payment within the meaning of Section 3.6.

21. Effective on and after the Effective Time, Appendix A-30 is amended by replacing the entirety of its text as follows:

> A-30 "Investment Fiduciary" means the Company acting through the Exelon Investment Office.

22. Effective on and after the Effective Time, a new Appendix A-30a shall be added immediately following Appendix A-30 as follows:

A-30a “Merger Agreement” means that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

23. Appendix A-35 of the Plan is amended by adding the following new sentence at the end thereof:

An individual shall cease to be a Participant upon the date the individual is no longer eligible to receive a benefit from this Plan (including, without limitation, upon his or her receipt of a Special Lump Sum Payment as defined in Section 3.6) or upon the individual’s Severance From Service Date if the individual is not eligible to receive a benefit from this Plan.

24. Effective January 1, 2013, Appendix A-35 of the Plan is amended by adding the following sentence to the end thereof:

No Employee hired on or after January 1, 2013 shall be a Participant, with the exception of Employees of the Employer set forth in Appendix G.

25. Effective on and after the Effective Time, Appendix A-38 of the Plan is amended by replacing the entirety of the text as follows:

A-38“Plan Administrator” means the Director, Employee Plans and Programs of the Company (or the position succeeding to that function).

26. Appendix A-44 of the Plan is amended by inserting the following new sentence before the last sentence of the first paragraph therein:

For distributions with a Benefit Commencement Date on or after December 1, 2012, other than as set forth in Section 3.6, the interest rate shall be the rate as defined in Section 417(e)(3)(C) of the Code for the fifth month preceding the calendar year in which such distribution is made or commences; provided, however, that the rate as defined in Section 417(e)(3)(C) of the Code for the month in which such distribution is made or commences shall be used if more favorable to the distributee during the period beginning December 1, 2012 through December 1, 2013.

27. Effective as of the June 1, 2012, Appendix A-45 is amended by replacing the entirety of the text as follows:

A-45 “Trustee” means the Northern Trust Company or any successor Trustee appointed by the Board of Directors.

28. Appendix G shall be deleted in its entirety, and replaced with a new Appendix G, attached hereto.

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IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its duly authorized officer on this ____ day of __________, 2012.

CONSTELLATION ENERGY GROUP, INC.

By: ____
Amy E. Best
Senior Vice President and
Chief Human Resource Officer

APPENDIX G

DESIGNATED SUBSIDIARIES

Employees of the following subsidiary are eligible to participate in the Plan on the same terms and conditions as set forth therein, except as otherwise provided below:

BGE Home Products and Services, LLC:

a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Home Products & Services, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. Notwithstanding the preceding sentence, an individual who is an Employee of Constellation Energy Source, Inc. on December 31, 1999, who transfers to BGE Home Products & Services, Inc. effective January 1, 2000, and was hired by Constellation Energy Source, Inc. after December 31, 1994, shall participate in PEP as modified in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Home Products & Services, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Home Products & Services, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e); 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Home Products & Services, Inc. This (ii) is not applicable to a Participant who received benefits under the Special Window for Employees Employed by BGE Home (as part of BGE Home's closing of its retail appliance and merchandise stores and the reorganization of BGE Home because of that closing) under the Constellation Energy Group, Inc. Severance Plan.

(iii) The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iv) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Home Products & Services, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

Employees of the following subsidiaries who were hired prior to January 1, 2013 are eligible to participate in the Plan on the same terms and conditions set forth therein, except as set forth below.

Constellation Power, Inc.

Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.) Constellation Power Source Generation, Inc.

Constellation Energy Source, Inc.

BGE Home Products and Services, LLC (formerly known as BGE Home Products and Services, Inc.) [1]

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[1] a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Home Products & Services, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. Notwithstanding the preceding sentence, an individual who is an Employee of Constellation Energy Source, Inc. on December 31, 1999, who transfers to BGE Home Products & Services, Inc. effective January 1, 2000, and was hired by Constellation Energy Source, Inc. after December 31, 1994, shall participate in PEP as modified in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.
b. Participants who are Employees of BGE Home Products & Services, Inc. shall have the following modifications to PEP:
(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Home Products & Services, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.
(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e); 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Home Products & Services, Inc. This (ii) is not applicable to a Participant who received benefits under the Special Window for Employees Employed by BGE Home (as part of BGE Home's closing of its retail appliance and merchandise stores and the reorganization of BGE Home because of that closing) under the Constellation Energy Group, Inc. Severance Plan.
(iii) The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.
(iv) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Home Products & Services, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

BGE Commercial Building Systems, Inc. [2]

[2] a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Commercial Building Systems, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding sentence will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Commercial Building Systems, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Commercial Building Systems, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e). 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Commercial Building Systems, Inc. The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iii) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Commercial Building Systems, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

Baltimore Gas and Electric Company [3]

Constellation Nuclear Services, Inc.

Constellation Generation Group, LLC

Constellation Operating Services, Inc.; Constellation Operating Services; COSI Central Wayne, Inc. (Employees represented by a union under a collective bargaining agreement are not eligible to participate); COSI Synfuels, Inc.; COSI Sunnyside, Inc.; COSI Puna, Inc.; PCI Operating Company Partnership [4]

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[3] With respect to an Employee of the Comfort Link division of Baltimore Gas and Electric Company, only individuals who are both a Participant on December 31, 1999 and an Employee of the Comfort Link division of Baltimore Gas and Electric Company on January 1, 2000, shall be eligible to participate in the Plan. Notwithstanding anything in the Plan to the contrary, the Vice-Chairman of Baltimore Gas and Electric Company will not be eligible to participate in this Plan.

[4] Employees of each listed subsidiary are eligible for participation in PEP effective January 1, 2003.

For purposes of 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which an Employee first performed an hour of service for the subsidiary. However, if the Participant was an Employee on January 1, 2003 and was employed by one of the following entities on the day immediately preceding the date the Employee became employed by the subsidiary, by A/C Power or by Trona Operating Partners, G.P. (or one of their subsidiaries), the Employment Commencement Date shall be the date on which the Employee first performed an hour of service for such entity (but in no event prior to any date noted in parentheses below):

Malacha Power Project, Inc.
Sunnyside Operating Associates
Niagara Mohawk Power Corporation
Consolidated Edison Company of New York (but only if the Employee was hired by COSI Astoria after August 20, 1999)
OESI Power (but only if the Employee was transferred to Constellation Operating Services, Inc. or one of its subsidiaries from OESI Power on January 6, 1993)
Kerr McGee Corporation—(but only if the Employee became an employee of Constellation Operating Services, Inc., A/C Power, or Trona Operating Partners, G.P. on December 1, 1990)
Ahlstrom Pyropower (or any other employer wholly or partially owned directly or indirectly, by Ahlstrom Pyropower (or any successor thereto))
Ultrasystems, Inc.
Hadson Corporation
LG&E Power, Inc
LUZ International
U C Operating Services
Panther Creek Fuels Company
Nevada Operations, Inc.
Central Wayne County Sanitation Authority
U. S. Generating (COSI Carr Street)
Ormat Energy Systems, Inc.
Ormat Systems, Inc.
Baltimore Gas and Electric Company (or any other employer wholly or partially owned directly or indirectly, by Baltimore Gas and Electric Company (or any successor thereto)) A/C Power

For purposes of 2.1 and A-31, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Normal Retirement.
For purposes of 2.2 and A-19, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Early Retirement.
For purposes of 4.3, Credited Service shall only include months beginning on or after January 1, 2003 during which an Employee works at least one hour for the Employer while classified as a Full-Time Employee.

Constellation NewEnergy, Inc[5]

5 Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.

CNE Gas Holdings, Inc.[6]

Exelon Business Services Corporation[7]

Exelon Generation Company, LLC[8]

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6 Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.

7 For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.

8 For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.

Exhibit 10.67

**THIRD AMENDMENT TO THE
PENSION PLAN OF
CONSTELLATION ENERGY GROUP, INC.
(Amended and Restated Effective January 31, 2012)**

WHEREAS, Exelon Corporation (the "Company") sponsors the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012) (the "Plan"); and

WHEREAS, the Company desires to amend the Plan to reflect additional guidance issued with respect to Section 436 of the Internal Revenue Code of 1986, as amended, to clarify the definition of "highly compensated employee" applicable under the Plan, to clarify the benefit formula for rehired employees, to limit participation in the Plan on and after January 1, 2013 and to make certain other changes.

NOW, THEREFORE, RESOLVED, that pursuant to the power of amendment contained in Article IX of the Plan, the Plan is amended effective January 1, 2013, except as otherwise stated below, as follows:

1. Section 1.1 of the Plan is amended to read as follows:

> 1.1 Automatic PEP Participation—Except as provided in 1.2 and the last sentence below, each Full-Time Employee of the Company, or of those subsidiaries and affiliates of the Company which are designated by the Board of Directors (as reflected in Appendix G), shall become a Participant in PEP on the date he/she becomes a Full-Time Employee. (Notwithstanding the previous sentence, effective July 23, 2010, Executive Group may designate such subsidiaries and affiliates if such designations have less than a $10 million impact on the Plan's accumulated benefit obligation per designation. At least annually, the Company's Chief Executive Officer shall report all such subsidiary and affiliate designations to the Board of Directors.) In addition, each Employee who is reemployed as a Full-Time Employee of the Company, or those subsidiaries and affiliates of the Company which are designated by the Board of Directors shall become a Participant in PEP on the date of his/her Adjusted Employment Commencement Date and shall not be eligible to participant in the Traditional Pension Plan with respect to his/her period of reemployment. An Employee

classified in a job description as an On-Call Employee, a leased employee within the meaning of Code Section 414(n)(2), or a co-op, work study or summer Employee shall not become a Participant in the Plan while classified in the sole judgment of the Employer as an On-Call Employee, a leased employee, or a co-op, work study or summer Employee. Notwithstanding anything contained herein to the contrary, no Employee whose Employment Commencement Date is on or after January 1, 2013 shall be eligible to participate in the Plan, with the exception of an Employee employed by BGE Home Products & Services, LLC.

2. Section 1.2 of the Plan is amended by adding the following new sentence at the end thereof:

Notwithstanding anything contained herein to the contrary, a Participant who is reemployed as an Employee shall not be a Participant in the Traditional Pension Plan, and shall not accrue any benefits under the Traditional Pension Plan, with respect to his/her period of reemployment. The Participant's Gross Pension under the Traditional Pension Plan shall be computed based solely on such Participant's Credited Service and Average Pay during the Employee's period of participation in the Traditional Pension Plan.

3. The second and third sentences of Section 3.2(d) of the Plan are amended to read as follows:

Except as provided in 3.2(e), monthly pension payments shall cease upon the Employer's reemployment of a Participant as an Employee. If the Participant's monthly pension payments cease as provided in the preceding sentence, upon the Participant's subsequent termination of employment with the Employer, the Participant's Gross Pension shall be recalculated and adjusted (including the adjustment described in 3.4(a)) and the Participant shall be given a new election with respect to the form and timing of his/her pension payments if such election otherwise would be available to the Participant

4. Section 3.2 of the Plan is amended by inserting the following new paragraph (e) at the end thereof:

3.2(e) Continued Payment of Benefits for Certain Rehired Participants . Notwithstanding anything contained herein to the contrary, a Participant who is reemployed as an Employee while receiving monthly pension payments may continue receiving such payments during his/her reemployment if the Participant executes a written waiver of his/her rights to participate in, and accrue benefits under, the Plan with respect to the Participant's period of reemployment. The Gross Pension of a Participant described in this 3.2(e) shall not be recalculated, adjusted or increased upon the Participant's subsequent termination of employment and such Participant shall not have an Adjusted Employment Commencement Date for purposes of the Plan.

5. The first sentence of Section 3.4(a) of the Plan is amended to read as follows:

The provisions of this 3.4(a) apply if, as described in 3.2(d), monthly pension payments cease upon the Employer's reemployment of a Participant as an Employee, and the Participant's Gross Pension is required to be recalculated and adjusted upon the Participant's subsequent termination of employment with the Employer.

6. A new Section 8.13 shall be added immediately following Section 8.12 as follows:

8.13 Definition of Highly Compensated Employee for Purposes of Legal Requirements . Wherever applicable for purposes of satisfying legal requirements applicable to the Plan, the term "highly compensated employee" shall mean any Employee who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q)(1)(B)(ii) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its affiliates when ranked on the basis of compensation paid during such preceding Plan Year.

7. Appendix A-35 of the Plan is amended by replacing the last sentence thereof with the following new sentence:

No Employee whose Employment Commencement Date is on or after January 1, 2013 shall be a Participant, with the exception of an Employee employed by BGE Home Products & Services, LLC.

8. Effective January 1, 2010, a new Appendix B-4 shall be added immediately following Appendix B-3 as follows:

B-4 Benefit Restrictions as a Result of Funding – Notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's adjusted funding target attainment percentage is at or below the following levels.

(a) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 80%, But Not Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 80% (or would be less than 80% to the extent described in subparagraph (a) 2. below) but is not less than 60%, then the limitations set forth in this paragraph (a) apply

1. 50% Limitation on Single Sum Payments, Other Accelerated Forms of Distribution, and Other Prohibited Payments . A Participant or Alternate Beneficiary is not permitted to elect, and the Plan shall not pay, a lump sum distribution or other optional form of distribution that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, unless the present value of the portion of the benefit that is being paid in a prohibited payment does not exceed the lesser of:

(i) 50% of the present value of the benefit payable in the optional form of benefit that includes the prohibited payment; or

(ii) 100% of the PBGC maximum benefit guarantee amount (as defined in Section 1.436-1(d)(3)(iii)(C) of the Treasury Regulations).

The limitation set forth in this subparagraph (a) 1. does not apply to any payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant. If an optional form of benefit that is otherwise available under the terms of the Plan is not available to a Participant or Alternate Beneficiary as of the annuity starting date because of the application of the requirements of this subparagraph (a) 1., the Participant or Alternate Beneficiary is permitted to elect to bifurcate the benefit into unrestricted and restricted portions (as described in Section 1.436-1(d)(3)(iii)(D) of the Treasury Regulations). The Participant or Alternate Beneficiary may also elect any other optional form of benefit otherwise available under the Plan at that annuity starting date that would satisfy the 50% limitation described in subparagraph (a) 1. (i) above or the PBGC maximum benefit guarantee amount described in subparagraph (a) 1. (ii) above, or may elect to defer the benefit in accordance with any general right to defer commencement of benefits under the Plan.

2. Plan Amendments Increasing Liability for Benefits . No amendment to the Plan that has the effect of increasing liabilities of the Plan by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accrual, or changing the rate at which benefits become nonforfeitable shall take effect in a Plan Year if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 80%; or

(ii) 80% or more, but would be less than 80% if the benefits attributable to the amendment were taken into account in determining the adjusted funding target attainment percentage.

The limitation set forth in this subparagraph (a) 2. does not apply to any amendment to the Plan that provides a benefit increase under a Plan formula that is not based on compensation, provided that the rate of such increase does not exceed the contemporaneous rate of increase in the average wages of Participants covered by the amendment.

(b) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 60% (or would be less than 60% to the extent described in subparagraph (b) 2. below), then the limitations in this paragraph (b) apply.

1. Single Sums, Other Accelerated Forms of Distribution, and Other Prohibited Payments Not Permitted . A Participant or Alternate Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment. The limitation set forth in this subparagraph (b) 1. does not apply to any payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

2. Shutdown Benefits and Other Unpredictable Contingent Event Benefits Not Permitted to Be Paid . An unpredictable contingent event benefit with respect to an unpredictable contingent event occurring during a Plan Year shall not be paid if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 60%; or

(ii) 60% or more, but would be less than 60% if the adjusted funding target attainment percentage were redetermined applying an actuarial assumption that the likelihood of occurrence of the unpredictable contingent event during the Plan Year is 100%.

3. Benefit Accruals Frozen . Benefit accruals under the Plan shall cease as of the applicable section 436 measurement date. In addition, if the Plan is required to cease benefit accruals under this subparagraph (b) 3., then the Plan is not permitted to be amended in a manner that would increase the liabilities of the Plan by reason of an increase in benefits or establishment of new benefits.

(c) Limitations Applicable If the Plan Sponsor Is In Bankruptcy . Notwithstanding any other provisions of the Plan, a Participant or Alternate Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date that occurs during any period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, except for payments made within a Plan Year with an annuity starting date that occurs on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. In addition, during such period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, except for payments that occur on a date within a Plan Year that is on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. The limitation set forth in this paragraph (c) does not apply to any payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(d) Provisions Applicable After Limitations Cease to Apply .

1. Resumption of Prohibited Payments. If a limitation on prohibited payments under subparagraph (a) 1., (b) 1., or (c) of this Section applied to the Plan as of a section 436 measurement date, but that limit no longer applies to the Plan as of a later section 436 measurement date, then that limitation does not apply to benefits with annuity starting dates that are on or after that later section 436 measurement date.

2. Resumption of Benefit Accruals. If a limitation on benefit accruals under subparagraph (b) 3. of this Section applied to the Plan as of a section 436 measurement date, but that limitation no longer applies to the Plan as of a later section 436 measurement date, then benefit accruals shall resume prospectively and that limitation does not apply to benefit accruals that are based on service on or after that later section 436 measurement date, except as otherwise provided under the Plan. The Plan shall comply with the rules relating to partial years of participation and the prohibition on double proration under Department of Labor Regulation Section 2530.204-2(c) and (d).

3. Shutdown and Other Unpredictable Contingent Event Benefits . If an unpredictable contingent event benefit with respect to an unpredictable contingent event that occurs during the Plan Year is not permitted to be paid after the occurrence of the event because of the limitation of subparagraph (b) 2. of this Section, but is permitted to be paid later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan

Year that meets the requirements of Section 1.436-1(g)(5)(ii)(B) of the Treasury Regulations), then that unpredictable contingent event benefit shall be paid, retroactive to the period that benefit would have been payable under the terms of the Plan (determined without regard to subparagraph (b) 2. of this Section). If the unpredictable contingent event benefit does not become payable during the Plan Year in accordance with the preceding sentence, then the Plan is treated as if it does not provide for that benefit.

4. Treatment of Plan Amendments That Do Not Take Effect. If a Plan amendment does not take effect as of the effective date of the amendment because of the limitation of subparagraph (a) 2. or (b) 3. of this Section, but is permitted to take effect later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan Year that meets the requirements of Section 1.436-1(g)(5)(ii)(C) of the Treasury Regulations), then the Plan amendment must automatically take effect as of the first day of the Plan Year (or, if later, the original effective date of the amendment). If the Plan amendment cannot take effect during the same Plan Year, then it shall be treated as if it were never adopted, unless the Plan amendment provides otherwise.

(e) Notice Requirement. Written notice to Participants and Beneficiaries shall be provided within 30 days, in accordance with Section 101(j) of ERISA, if the Plan becomes subject to a limitation described in subparagraph (a) 1., (b), or (c) of this Section.

(f) Methods to Avoid or Terminate Benefit Limitations. Application of one or more of the benefit limitations set forth in paragraphs (a), (b) and (c) of this Section for a Plan Year may be avoided or terminated through the use of employer contributions, by increasing the amount of Plan assets which are taken into account in determining the adjusted funding target attainment percentage and by other methods in accordance with Sections 436(b)(2), (c)(2), (e)(2) and (f) of the Code and Section 1.436-1(f) of the Treasury Regulations.

(g) Plan Operations for Periods Prior to and After Certification of Plan's Adjusted Funding Target Attainment Percentage .

1. In General. For any period during which a presumption under Section 436(h) of the Code and Section 1.436-1(h) of the Treasury Regulations applies to the Plan, the limitations under paragraphs (a) through (c) of this Section are applied to the Plan as if the adjusted funding target attainment percentage for the Plan Year were the presumed adjusted funding target attainment percentage determined under the rules of Section 436(h) of the Code and Section 1.436-1(h)(1), (2), or (3) of the Treasury Regulations. These presumptions are set forth in subparagraphs (g) 2. though (g) 4. below.

2. Presumption of Continued Underfunding Beginning First Day of Plan Year. If a limitation under paragraph (a), (b) or (c) of this Section applied to the Plan on the last day of the preceding Plan Year, then, commencing on the first day of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g) 3. or (g) 4. below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the adjusted funding target attainment percentage in effect on the last day of the preceding Plan Year; and

(ii) The first day of the current Plan Year is a section 436 measurement date.

3. Presumption of Underfunding Beginning First Day of Fourth Month. If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the fourth month of the Plan Year and the Plan's adjusted funding target attainment percentage for the preceding Plan Year was either at least 60% but less than 70% or at least 80% but less than 90%, or is described in Section 1.436-1(h)(2)(ii) of the Treasury Regulations, then, commencing on the first day of the fourth month of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g) 4. below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the Plan's adjusted funding target attainment percentage for the preceding Plan Year reduced by 10 percentage points; and

(ii) The first day of the fourth month of the current Plan Year is a section 436 measurement date.

4. Presumption of Underfunding On and After First Day of 10th Month. If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the 10th month of the Plan Year (or if the Plan's enrolled actuary has issued a range certification for the Plan Year pursuant to Section 1.436-1(h)(4)(ii) of the Treasury Regulations but has not issued a certification of the specific adjusted funding target attainment percentage for the Plan by the last day of the Plan Year), then, commencing on the first day of the 10th month of the current Plan Year and continuing through the end of the Plan Year:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be less than 60%; and

(ii) The first day of the 10th month of the current Plan Year is a section 436 measurement date.

(h) Plan Termination and Other Special Rules.

1. Plan Termination. The limitations on prohibited payments in subparagraphs (a) 1., (b) 1., and (c) of this Section do not apply to prohibited payments that are made to carry out the termination of the Plan in accordance with applicable law. Any other limitations under this Section do not cease to apply as a result of termination of the Plan.

2. Special Rules Relating to Unpredictable Contingent Event Benefits and Plan Amendments Increasing Benefit Liability. During any period in which none of the presumptions under paragraph (g) of this Section apply to the Plan and the Plan's enrolled actuary has not yet issued a certification of the Plan's adjusted funding target attainment percentage for the Plan Year, the limitations under subparagraphs (a) 2. and (b) 2. of this Section shall be based on the "inclusive presumed adjusted funding target attainment percentage" for the Plan, as such term is described in, and calculated in accordance with the rules of, Section 1.436-1(g)(2)(iii) of the Treasury Regulations.

3. Payments Under Social Security Leveling Options. For purposes of determining whether the limitations under subparagraph (a) 1. or (b) 1. of this Section apply to payments under a social security leveling option, within the meaning of Section 436(j)(4)(C)(i) of the Code, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under Section 436(j)(3) of the Code and any Treasury Regulations or other published guidance thereunder issued by the Internal Revenue Service.

4. Limitation on Benefit Accruals. For purposes of determining whether the accrual limitation under subparagraph (b) 3. of this Section applies to the Plan, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under Section 436(j)(3) of the Code (except as provided under section 203(b) of the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010, if applicable).

5. Interpretation of Provisions. The limitations imposed by this Section shall be interpreted and administered in accordance with Section 436 of the Code and Section 1.436-1 of the Treasury Regulations.

(i) Definitions. The definitions in the following Treasury Regulations apply for purposes of this Section: Section 1.436-1(j)(1) defining adjusted funding target attainment percentage; Section 1.436-1(j)(2) defining annuity starting date; Section 1.436-1(j)(6) defining prohibited payment; Section 1.436-1(j)(8) defining section 436 measurement date; and Section 1.436-1(j)(9) defining an unpredictable contingent event and an unpredictable contingent event benefit.

(j) Effective Date. The rules in this Section are effective for Plan Years beginning after December 31, 2007.

9. Appendix G is amended by adding the following after “Exelon Generation Company, LLC” and adding a footnote corresponding to each item on the list to read as below:

CER Generation, LLC

Footnote: Effective April 1, 2008. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this entity.

*****

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President and Chief Human Resources Officer, on this ____ day of December, 2013.

EXELON CORPORATION

By: ________________________________

Amy E. Best
Senior Vice President and
Chief Human Resource Officer

Exhibit 10.68

CONSTELLATION ENERGY GROUP, INC.
EMPLOYEE SAVINGS PLAN

Amended and Restated Effective January 31, 2012

TABLE OF CONTENTS

CONSTELLATION ENERGY GROUP, INC.

EMPLOYEE SAVINGS PLAN

Article I – Purpose and Nature of the Plan

1.1 Purpose of the Plan

The Plan is designed as a stock bonus plan. Eligible Employees have the opportunity to save on a regular and long-term basis, and in the process acquire or sustain a proprietary interest in the success of the Company. The Plan is intended to meet the requirements of the provisions of Code Section 401(a). The Plan is also intended to meet the requirements of an Employee Stock Ownership Plan under Code Section 4975(e)(7) as well through February 28, 2002. Effective February 1, 2006, the portion of the Plan consisting of the CEG Common Stock Fund is intended to be an Employee Stock Ownership Plan under Code Section 4975(e)(7). That portion of the Plan is intended to be primarily invested in Common Stock which constitutes employer securities (within the meaning of Code Section 409(l).

1.2 Nature of the Plan – General

The Plan is structured to permit three (3) general categories of Employee participation. First, eligible Employees may elect to participate by choosing to contribute to the Plan under the After-Tax Option, the Before-Tax Option, or a combination of both. Company Matching Contributions, as provided under the Plan, are made with respect to a Participant's contributions under the After-Tax and/or Before-Tax Options. Second, eligible Employees may elect to participate by contributing to the Plan through the rollover of an Eligible Rollover Distribution from an Eligible Retirement Plan as provided under the rollover provisions of the Plan. Third, Employees or former Employees may participate by virtue of having a balance established in an Employee Stock Account.

1.3 After-Tax and Before-Tax Options

1.3(a) After-Tax Option

Under the After-Tax Option, an eligible Employee may contribute a percentage of Eligible Compensation to the Plan through payroll deduction, subject to the limitations of Articles III and IV and Appendix B of the Plan. Amounts contributed under the After-Tax Option are contributions described in Code Section 401(m) and are included in the taxable income of the Employee in the year of the contribution. Earnings on After-Tax Option contributions are taxed to the Employee when distributed or withdrawn from the Plan.

1.3(b) Before-Tax Option

Under the Before-Tax Option, an eligible Employee may contribute a percentage of Eligible Compensation to the Plan through payroll deduction, subject to the limitations of Articles III and IV and Appendix B of the Plan. Amounts contributed under the Before-Tax Option are contributions described in Code Section 401(k) and are not included in the federal taxable income of the Employee in the year of the contribution. Before-Tax Option contributions and earnings thereon are taxed to the Employee when distributed or withdrawn from the Plan.

1.3(c) Company Matching Contributions

Under the Company Matching Contribution provisions of the Plan, the Company contributes a Company Matching Contribution with respect to each eligible Employee, subject to the limitations of Articles III and IV and Appendix B of the Plan. Company Matching Contributions are contributions described in Code Section 401(m) and are not included in the taxable income of the Employee in the year of the contribution. Company Matching Contributions and earnings thereon are taxed to the Employee when distributed or withdrawn from the Plan.

1.4 Rollover

Under the rollover provisions of the Plan, an eligible Employee may establish a Rollover Account within the Plan by transferring all or a portion of an Eligible Rollover Distribution (except any portion of any distribution that is not includable in gross income unless specifically provided for under Section 3.3) from another Eligible Retirement Plan. Such transfers can only be in the form of cash, except as otherwise provided in Appendix E or under Section 3.3.

1.5 Employee Stock Account

An Employee Stock Account was automatically established within the Plan for each Employee or former Employee upon the Plan's receipt of (i) Baltimore Gas and Electric Company contributions made on behalf of such Employee under the Corporate Performance Award Program, and/or (ii) transfers of the Employee's or former Employee's account balance in the Baltimore Gas and Electric Company Employee Stock Ownership Plan upon such plan's Termination.

1.6 Plan Mergers

The following plans (or portions thereof) have been merged into this Plan as of the corresponding effective dates:

Merged Plan Name	Merger Effective Date
Constellation Operating Services, Inc. Retirement Plan	April 1, 2003
A/C Power Retirement Plan	April 1, 2003
Trona Operating Partners Retirement Plan	April 1, 2003
Non-Represented Employee Savings Plan for Nine Mile Point	October 1, 2005
Cornerstone Energy, Inc. 401(k) Plan	July 1, 2007

Article II – Eligibility and Participation

2.1 Eligibility

2.1(a) Eligibility In General

Each Full-Time Employee of the Company, or of those other Employers which are designated as Participating Employers by the Designating Authority, as reflected in Appendix E, is eligible to become a Participant in the Plan through the After-Tax and Before-Tax Options and/or rollover provisions beginning on the first day of the first pay period as soon as practicable following his date of hire by a Participating Employer; provided, however, that any person whose conditions of employment are covered by any collective bargaining agreement to which the Employer is a party shall be ineligible to become a Participant unless and until that agreement specifically provides for such person's participation in the Plan. Each such Full-Time Employee of a Participating Employer is eligible to become a Participant only in those aspects of the Plan specified by the Designating Authority.

An Employee classified in a job description as an On-Call Employee or an Employee who is a leased employee within the meaning of Code Sections 414(n)(2) and 414(o)(2), is not eligible to participate in the Plan while classified in the sole judgment of the Employer as an On-Call Employee or leased employee.

2.1(b) Eligibility After Reemployment

If an Employee who terminated service is reemployed as a Full-Time Employee of the Company or another Participating Employer, as reflected in Appendix E, the Employee shall be eligible to participate through the After-Tax and Before-Tax Options and/or rollover provisions beginning on the first day of the first pay period as soon as practicable following his date of reemployment. This reemployment rule applies whether the Employee was a Participant, was eligible to be a Participant, or was ineligible to be a Participant due to failure to meet the Plan's service requirement for eligibility, on the date of termination.

2.1(c) Change in Status

An Employee who becomes represented by a collective bargaining agreement with the Employer shall have the accounts maintained under this Plan transferred to the plan established pursuant to the collective bargaining agreement as soon as administratively feasible.

An Employee who ceases to be represented by a collective bargaining agreement with the Employer shall become eligible to participate in the Plan, and the accounts maintained under the plan established pursuant to the collective bargaining agreement shall be transferred to the Plan as soon as administratively feasible. Such an Employee shall become a Participant in the Plan as of the date of such transfer and shall be eligible to make contributions to the Plan in accordance with Article III of the Plan as soon as administratively feasible

2.2 Participation

2.2(a) After-Tax and Before-Tax Options

Participation in the After-Tax and Before-Tax Options is voluntary. An Employee who satisfies the eligibility requirements of Section 2.1 can elect to become a Participant by submitting an Appropriate Request with the Plan Administrator. In making the Appropriate Request, the Employee must (i) designate the rate of contribution under the After-Tax and/or Before-Tax Options; (ii) indicate the Investment Funds to which contributions under the After-Tax and/or Before-Tax Options will be allocated and the percentage allocated to each Investment Fund; and (iii) agree to be bound by the terms and conditions of the Plan, a copy of which will be furnished to the Employee upon request.

After-Tax Option contributions, which are taxed to the Participant when contributed to the Plan, are treated as direct contributions to the Plan by the Participant. Therefore, an Appropriate Request submitted with respect to the After-Tax Option authorizes the Company to deduct a stated percentage of the Participant's Eligible Compensation from his pay and transmit the amount deducted to the Plan to be invested.

Before-Tax Option contributions, which are not taxed to the Participant (for federal income tax purposes) until distributed from the Plan, are treated as reductions in the salary of the Participant which are then contributed to the Plan by the Company on behalf of the Participant. Therefore, pursuant to an Appropriate Request submitted with respect to the Before-Tax Option, the Participant undertakes to forego the receipt of a stated percentage of Eligible Compensation. In return, the Company will contribute to the Plan an amount equal to the deferral.

An eligible Employee who does not elect to become a Participant in the After-Tax and/or Before-Tax Options at the earliest possible eligibility date as provided in Section 2.1, may elect to become a Participant at a later date by submitting an Appropriate Request with the Plan Administrator. The election to participate will become effective beginning on the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator.

2.2(b) Rollover

A Participant who satisfies the eligibility requirements of Section 2.1 and who wishes to roll over all or a portion of an Eligible Rollover Distribution (except any portion of any distribution that is not includable in gross income unless specifically allowed under Section 3.3) as provided in Section 3.3 may do so by submitting an Appropriate Request with the Plan Administrator. A Participant will continue to be considered a Participant for purposes of eligibility for rollovers as long as amounts are held in the Participant's Plan accounts, regardless of such Participant's eligibility to make further contributions to the Plan. The Participant will be required to submit documentation necessary to support the qualification of the rollover as requested by the Plan Administrator, or designees of the Plan Administrator, before the Plan Administrator will authorize the establishment of a Rollover Account for the Participant. If, in the judgment of the Plan Administrator or the Plan Administrator's designees, the documentation does not adequately support the qualification of the rollover amount, the Plan Administrator has the authority under the Plan to disallow a rollover contribution to the Plan.

The Participant must indicate as part of the Appropriate Request the Investment Funds to which rollover contributions will be allocated and the percentage or dollar amount allocated to each Investment Fund. The Participant must also agree to be bound by the terms and conditions of the Plan, a copy of which will be furnished to the Employee upon request.

2.2(c) Employee Stock Account

An Employee or former Employee for whom a balance in an Employee Stock Account has been established under the Plan is automatically a Participant. Participation in the Plan through the establishment of an Employee Stock Account does not affect an Employee's eligibility for or participation in the After-Tax and Before-Tax Options or the rollover provision.

Article III – Contributions to the Plan

3.1 After-Tax and Before-Tax Options

3.1(a) Rate of Contribution

Subject to the limitations described in Article IV and Appendix B, a Participant may contribute to the After-Tax Option of the Plan an amount equal to not more than fifteen percent (15%) of the Participant's Eligible Compensation, and to the Before-Tax Option of the Plan an amount equal to not more than fifty percent (50%) of the Participant's Eligible Compensation; provided, however, that a Participant may contribute to the After-Tax and/or Before-Tax Options of the Plan an amount equal in aggregate to not more than fifty (50%) of the Participant's Eligible Compensation.

Notwithstanding anything else in the Plan including the above, Participants who have attained age 50 before the close of the Plan Year are eligible to make "catch-up contributions" in accordance with, and subject to the limitations of, Section 414(v) of the Code. Such catch-up contributions shall be treated for purposes of the Plan as Before-Tax Option contributions, but shall not be subject to the Company Matching Contribution provisions, and shall not be taken into account for purposes of the required limitations of Sections 402(g) and 415 of the Code. The Plan will not be treated as failing to satisfy the provisions of the Plan implementing the requirements of Sections 401(k)(3), 401(k)(11), 401(k)(12), 410(b), or 416 of the Code, as applicable, by reason of the making of such catch-up contributions.

The rate of contribution must be in multiples of one percent (1%); provided, however, that "catch-up contributions" must be in a specified dollar amount per pay period. In the event a Participant's Compensation in any Payroll Period is insufficient to make contributions at the rate elected by the Participant, the amount not contributed as a result of the insufficiency may not be contributed in the succeeding Payroll Period(s). A Participant's contributions shall be paid into the Plan as soon as practicable and shall be allocated to the Participant Contribution Account(s) in accordance with the Participant's instructions as indicated by the Appropriate Request submitted with the Plan Administrator.

3.1(b) Basic and Supplemental Contributions Under the After-Tax and Before-Tax Options

For purposes of determining the Company Matching Contributions as well as for various withdrawal and loan provisions found in Articles VII and IX of the Plan, a Participant's contributions made through the After-Tax and/or Before-Tax Options are characterized as either Basic Contributions or Supplemental Contributions.

When, in accordance with a Participant's instructions, the total contribution is split in whole percentage points between the After-Tax and the Before-Tax Options, the contribution under the Before-Tax Option, up to and including the maximum amount permitted as a Basic Contribution, will be treated as a Basic Contribution. Should the contribution under the Before-Tax Option be less than the maximum amount permitted as a Basic Contribution, then a portion of the After-Tax Option contribution percentage (if any) equal to the difference between the Before-Tax Option contribution percentage and the maximum amount permitted as a Basic Contribution will be characterized as a Basic Contribution.

3.1(c) Change in Rate of Contribution

A Participant may elect to change his contribution rate in multiples of one percent (1%), or in such other multiples as may be specified by the Plan Administrator, by submitting an Appropriate Request to the Plan Administrator. Unless otherwise specified by the Plan Administrator, the change in the rate of contribution will become effective the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator.

3.1(d) Suspension of Participant Contributions

A Participant may elect to suspend his contributions to the After-Tax and/or Before-Tax Options of the Plan by submitting an Appropriate Request to the Plan Administrator. The suspension of contributions shall become effective the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator. A Participant may also elect to resume contributions by submitting an Appropriate Request to the Plan Administrator. Such a Participant's contributions will resume on the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator. A Participant may not make up contributions relating to the period in which contributions were suspended.

3.1(e) Leave of Absence

An authorized leave of absence shall not constitute a termination of employment, but shall, except as provided in Section 3.1(f), operate to suspend Participant contributions and related Company Matching Contributions. At the end of an authorized leave of absence, a Participant's After-Tax and/or Before-Tax Option contributions shall be automatically restarted based on the Participant's contribution election at the time the leave of absence began.

3.1(f) Military Leave of Absence

In accordance with the provisions of the Uniformed Services Employment and Reemployment Rights Act of 1994, an Employee returning from a military leave of absence may elect to contribute to the Plan, under the After-Tax and/or Before-Tax Options, an amount not to exceed the amount such Employee would have been permitted to contribute had the Employee not taken a military leave of absence. The election to make a contribution for the period of the military leave of absence is made by filing an Appropriate Request with the Plan Administrator. Contributions under this Section must be made in accordance with Code Section 414(u). At the time such contribution is made, the Employee must (i) designate the portion of the contribution made under the After-Tax and/or Before-Tax Options, and (ii) indicate the Investment Funds to which contributions under the After-Tax and/or Before-Tax Options shall be allocated. A Company Matching Contribution will be made in accordance with Section 3.2 on the portion of the Employee contribution that represents Basic Contributions. Any contribution to the Plan under this Section must be made during the period beginning with the date of return from the leave of absence and whose duration is three times the period of the Employee's service in the uniformed services, not to exceed five years.

An individual receiving a differential wage payment, as defined by Code Section 3401(h)(2) is treated as an Employee of the Employer. The differential wage payment is treated as Compensation, to the extent required under law, and the Plan is not treated as failing to meet the requirements of any provision described in Code Section 414(u)(1)(C) by reason of any contribution or benefit which is based on the differential wage payment. This paragraph applies only if the requirements of Code Section 414(u)(12)(B) and (C) are satisfied.

3.2 Company Matching Contributions

Subject to the limitations described in Article IV and Appendix B, the Company will contribute the Company Matching Contribution to the Plan on behalf of each Participant and as soon as practicable.

Company Matching Contributions will be made completely in cash or in shares of Common Stock having an aggregate value equal to the contribution the Company is required to make to the Plan under this Section 3.2. Prior to January 1, 2012, Company Matching Contributions are invested initially in the CEG Common Stock Fund. On and after January 1, 2012, Company Matching Contributions are invested in the Investment Funds designated by the Participant.

3.3 Rollover Contributions

A Participant may contribute to the Plan, in cash (or other property as set forth in Appendix E or as set forth below), all or a portion of an amount determined to be an Eligible Rollover Distribution (except any portion of any distribution that is not includable in gross income unless specifically allowed below). A Participant who rolls over an Eligible Rollover Distribution from the Employee Savings Plan for Constellation Energy Nuclear Group, LLC and the Represented Employee Savings Plan of Nine Mile Point to the Plan may rollover shares of CEG Common Stock in kind and may also rollover any promissory notes evidencing any loans under those plans in-kind. The Plan may accept a direct transfer of an Eligible Rollover Distribution that consists of after-tax employee contributions from the Employee Savings Plan for Constellation Energy Nuclear Group, LLC and the Represented Employee Savings Plan for Nine Mile Point, qualified plans, subject to any procedure established by the Plan. The Plan will account separately for any amounts so transferred.

A Participant may execute a rollover to the Plan of an Eligible Rollover Distribution (including, without limitation, an Eligible Rollover Distribution from the Pension Plan of Constellation Energy Group, Inc.) by either (i) contributing all or a portion of the distribution received by the Participant to the Plan within 60 days from the date the distribution is received, or (ii) having the Eligible Retirement Plan from which the Eligible Rollover Distribution is to be made, transfer the Eligible Rollover Distribution directly to the Plan. The Plan Administrator may designate the manner in which a direct transfer to the Plan can be made.

It is the intent of the Plan that any distribution eligible for rollover to the Plan meet the tax-free rollover requirements as set forth in the Code and the regulations promulgated thereunder, so that the amounts rolled over into the Plan will not jeopardize the tax-exempt status of the Plan or Trust or result in adverse tax consequences to the Company. The Plan Administrator may require the Employee to establish that amounts contributed to the Plan under the rollover provisions, meet the tax-free rollover requirements set forth in the Code.

3.4 Return of Company Contributions

At the discretion of the Plan Administrator, in the case of a Company contribution which is made under a mistake of fact, such contribution exclusive of earnings may be returned to the Company within one year after the payment of the contribution.

All Company contributions to the Plan shall be conditioned on their deductibility under Code Section 404 and, in the event the deduction for the contributions is disallowed by the Secretary of the Treasury, such contributions will be returned to the Company within one year of the disallowance.

Article IV – Limitations on Contributions to the Plan

4.1 General

In addition to the limitations on contributions imposed by the Plan under Article III, and subject to the “catch-up contributions” provisions in Section 3.1(a), contributions to the Plan under the After-Tax Option, the Before-Tax Option, and the Company Matching Contribution provisions will be limited by the Plan Administrator, to the extent necessary to enable the Plan to comply with the limitations prescribed by the Code. These limitations are summarized in Section 4.2 below and detailed in Appendix B.

4.2 Internal Revenue Code Limitations

To determine that the limitations on contributions to the Plan under the Code are not exceeded in any Plan Year, the following limitations will be monitored by the Plan Administrator or his designees no less frequently than annually.

4.2(a) Limitation on Participants’ Before-Tax Option Contributions

Before-Tax Option contributions on behalf of any Participant may not exceed the Code Section 402(g) limit ($13,000 in 2004 and as further adjusted under Code Section 402(g)(5)) for any Plan Year. The Plan Administrator may prospectively limit, during the Plan Year, Before-Tax Option contributions if it is determined that the Code Section 402(g) limitation would otherwise be exceeded for such Plan Year. Participants whose Before-Tax Option contributions are limited under this Section 4.2(a) are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant’s Before-Tax Option contribution percentage in excess of the limitation. If necessary, the Plan Administrator may distribute any excess amounts to the Participant in a post-Plan Year distribution. Detailed provisions governing the operation of this limitation under the Plan are set forth in Appendix B-1: Dollar Limitation on Participants’ Before-Tax Option Contributions.

4.2(b) Limitation on Total Annual Additions

The annual additions to a Participant's account during the Plan Year resulting from After-Tax Option contributions, Before-Tax Option contributions, and Company Matching Contributions may not under Code Section 415(c) exceed the Code Section 415(c)(1) limit.

As used in this Section 4.2(b) and Appendix B-2, compensation means compensation under Code Section 415(c)(3), including any items required to be included in compensation and excluding any items required to be excluded from compensation under Code Section 415(c)(3) and the regulations issued thereunder, and specifically incorporating the safe harbor definition of compensation under Treas. Reg. § 1.415(c)-2(d)(4) relating to information required to be reported under Code Sections 6041, 6051, and 6052. Any differential wage payments (as defined in Code Section 3401(h)(2)) shall be included in compensation for purposes of Code Section 415. Payments made by the later of 2-1/2 months after severance from employment or the end of the limitation year that includes the date of severance from employment are included in compensation for the limitation year if, absent a severance from employment, such payments would have been paid to the Participant while the Participant continued in employment with the Employer and are regular compensation for services during the Participant's regular working hours, compensation for services outside the Participant's regular working hours (such as overtime or shift differential), commissions, bonuses, or other similar compensation.

Compensation as used in this section 4.2(b) and Appendix B-2 is not permitted to reflect compensation that is in excess of the limitation under Code Section 401(a)(17) that applies to that limitation year.

4.2(c) Limitation on Participant Contributions Under the Before-Tax Option (ADP Test)

The actual deferral percentage of eligible Highly Compensated Employees may not exceed the actual deferral percentage of eligible Nonhighly Compensated Employees by an amount greater than the limitations of the Actual Deferral Percentage (ADP) Test under Code Section 401(k)(3). The Plan Administrator may prospectively limit, during the Plan Year, Before-Tax Option contributions of certain Highly Compensated Employees if it is determined that the ADP Test limitation would otherwise be exceeded for such Plan Year. Participants whose Before-Tax Option contributions are prospectively limited under this Section 4.2(d) are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation.

The Plan Administrator may also correct any excess Before-Tax Option contributions by distributing the excess amounts applicable to such Highly Compensated Employees in a post-Plan Year distribution, by making a Qualified Nonelective Contribution, or by recharacterizing excess amounts as After-Tax Option contributions. Detailed provisions governing the operation of this limitation under the Plan are set forth in Appendix B-4: Limitation on Participant Contributions Under the Before-Tax Option (ADP Test).

4.2(d) Limitation on After-Tax Option Contributions and Company Matching Contributions (ACP Test)

The actual contribution percentage of eligible Highly Compensated Employees may not exceed the actual contribution percentage of eligible Nonhighly Compensated Employees by an amount greater than the limitations of the Actual Contribution Percentage (ACP) Test under Code Section 401(m). The Plan

Administrator may prospectively limit, during the Plan Year, After-Tax Option contributions or Company Matching Contributions of certain Highly Compensated Employees if it is determined that the ACP Test limitation would otherwise be exceeded for such Plan Year. The Plan Administrator may also correct any excess After-Tax Option contributions or Company Matching Contributions by distributing the excess amounts to such Highly Compensated Employees in a post-Plan Year distribution. Detailed provisions governing the operation of this limitation under the Plan are set forth in Appendix B-5: Limitation on Participant Contributions Under the After-Tax Option and Company Matching Contributions (ACP Test).

Article V – Investment of Contributions and Determination of Account Balances

5.1 Investment of Contributions

5.1(a) Investment Funds

Contributions to the Plan will be invested in one or more of the following Investment Funds under the Plan:

(1) the CEG Common Stock Fund;

(2) the Default Investment Fund; or

(3) any Other Investment Fund(s) selected by the Investment Committee from time to time.

Dividends, interest, or other income, if any, received by the Trustee with respect to contributions in each Investment Fund shall be reinvested in the same Investment Fund, except to the extent distributed in accordance with Section 8.5(a).

In the event a Participant fails to make any investment elections with respect to any Participant Contributions, rollover contributions and, for periods on or after January 1, 2012, Company Matching Contributions, the portion of the Participant's accounts over which the Participant has not directed the investment shall first be invested in accordance with elections under the Before-Tax Option, then in elections under the After-Tax Option and then, if no elections are made under either the Before-Tax or After-Tax Option, invested in the Default Investment Fund. Any material provided to the Plan relating to a Participant's investment in the Default Investment Fund as a default investment as described above, including account statements, prospectuses and proxy voting material, will be provided to such Participant. The Default Fund is and has been intended to constitute a "qualified default investment alternative" as defined in DOL Reg. 2550.404c-5 and is intended to meet all requirements necessary to satisfy applicable law.

5.1(b) Investment of Participant Contributions

A Participant's contributions to the Plan under either the After-Tax Option or the Before-Tax Option, or under the rollover provisions of the Plan, shall be invested in one or more of the Investment Funds under the Plan, in accordance with instructions furnished to the Plan Administrator by the Participant as provided under Article II. Participant contributions to the Plan shall be allocated to the Investment Funds in any increments of one percent (1%) of the total contribution or in any other increments at the discretion of the Plan Administrator as selected by the Participant. A Participant may choose to invest contributions to the Plan under the After-Tax Option in the same different Investment Funds and at different percentages than contributions under the Before-Tax Option. Likewise, contributions under the rollover provisions of the Plan are not required to be invested in the same Investment Funds or in the same percentages as Participant Contributions under the After-Tax and/or the Before-Tax Options.

With respect to After-Tax Option, Before-Tax Option, or rollover contributions held by the Company pending transfer to the Trustee, no interest will be paid on such accumulated contributions prior to transfer to the Trustee. A Participant will not be able to withdraw under any circumstances monies contributed but not yet transferred to the Trustee.

Participant contributions shall be posted to Participants' accounts as soon as administrative feasible after such contributions are transferred to the Trustee.

5.1(c) Change in Investment of Participant Contributions

A Participant may change investment percentages for future contributions to the Investment Funds under the After-Tax and/or Before-Tax Options within the limits set forth in Section 5.1(b). Investment percentages may be changed at any time, by submitting an Appropriate Request in the form and manner prescribed by the Plan Administrator. The change will become effective as soon as administratively feasible.

5.1(d) Investment of Company Matching Contributions

Prior to January 1, 2012, all Company Matching Contributions shall be initially invested in the CEG Common Stock Fund. Participants may elect to transfer these contributions to other Investment Funds as soon as these contributions have been posted to provide for diversification of the Participant's investment pursuant to the interfund transfers provisions of Section 5.3(a).

Effective on and after January 1, 2012, all Company Matching Contributions shall be invested in accordance with instructions furnished to the Plan Administrator by the Participant as provided under Article III and this Article V for contributions to the Plan under the Before-Tax Option. Company Matching Contributions shall be posted as soon as administratively feasible after the date the contributions are transferred to the Trustee. Company Matching Contributions shall be allocated to the Investment Funds in any increments of one percent (1%) of the total contribution or in any other increments at the discretion of the Plan Administrator as selected by the Participant.

5.1(e) Investment of Employee Stock Account

A Participant's Employee Stock Account consists of Company contributions that were made under the Corporate Performance Award Program, amounts that were directly transferred by the Trustee of the terminated Baltimore Gas and Electric Company Employee Stock Ownership Plan, and earnings thereon. All contributions, transfers, and earnings in the Employee Stock Account were initially invested in the CEG Common Stock Fund. As with Company Matching Contributions, Participants may elect to transfer these contributions to other Investment Funds to provide for diversification of the Participant's investments pursuant to the interfund transfers provisions of Section 5.3(a).

5.1(f) Investment of Recharacterized Employee Contributions

Amounts contributed by a Participant under the Before-Tax Option which are subsequently recharacterized as contributions under the After-Tax Option because the limitations under Section 4.2(d) are exceeded, shall remain invested in the same Investment Funds in which such contributions were invested immediately prior to the recharacterization.

5.1(g) Investment of After-Tax Option Contributions Made Pursuant to Automatic Provisions of Section 4.2(a) and Section 4.2(d)

Amounts contributed by a Participant under the After-Tax Option pursuant to the automatic provision contained in Sections 4.2(a) and 4.2(d) relating to prospective limitations, shall be invested in the same Investment Funds using the same investment percentages as elected by the Participant for other contributions being made under the After-Tax Option. Lacking instructions from the Participant regarding investments under the After-Tax Option, such contributions shall be invested in the same Investment Funds using the same investment percentages elected by the Participant under the Before-Tax Option.

5.2 Investment Fund Accounts

5.2(a) Participant Contribution Account

A Participant Contribution Account will be established in each Investment Fund to which Participant Contributions under the After-Tax and/or Before-Tax Options are invested.

5.2(b) Company Matching Contribution Account

Prior to January 1, 2012, a Company Matching Contribution Account will be established in the CEG Common Stock Fund for each Participant. This account will contain all Company Matching Contributions made on behalf of the Participant prior to January 1, 2012 with respect to Basic Contributions under the After-Tax and/or Before -Tax Options.

Company Matching Contribution Accounts will also be established in the Default Investment Fund and the Other Investment Funds as elected by the Participant for Participants requesting transfer for amounts from the Company Matching Contribution Account in the CEG Common Stock Fund to other Investment Funds under the provisions of Section 5.3(a) and for all Company Matching Contributions made on behalf of the Participant on and after January 1, 2012 with respect to Basic Contributions under the After-Tax and/or Before-Tax Options.

5.2(c) Employee Stock Account

Contributions were made to an Employee Stock Account that was established in the CEG Common Stock Fund on behalf of the Participant under the Corporate Performance Award Program. The Employee Stock Account also includes any amounts directly transferred by the Trustee of the terminated Baltimore Gas and Electric Company Employee Stock Ownership Plan.

Dividends, if any, received by the Trustee (on or before the January 1, 2002 Common Stock dividend payment date) with respect to amounts in the Employee Stock Account in the CEG Common Stock Fund shall be distributed to Participants as provided in Section 8.5. The Trustee shall invest, no less frequently than quarterly, any interest earned on such dividends prior to their distribution, in shares of Common Stock, and allocate such shares to the Participant's Employee Stock Account in the CEG Common Stock Fund. Employee Stock Accounts will also be established in the Default Investment Fund and the Other Investment Funds for Participants requesting transfer of amounts from the Employee Stock Account in the CEG Common Stock Fund to other Investment Funds under the provisions of Section 5.3(a).

5.2(d) Rollover Account

A Rollover Account will be established in each Investment Fund to which Participant rollover contributions under the rollover provisions of the Plan are invested in accordance with Participant instructions.

5.3 Interfund Transfers

5.3(a) Generally

Upon submitting an Appropriate Request to the Plan Administrator, a Participant may elect to transfer from one Investment Fund to another, in whole or in part, in multiples of 1 percentage, whole number of shares or whole dollar amounts that have already been contributed by the Participant to the Plan under the After-Tax Option, the Before-Tax Option, and/or the rollover provisions of the Plan, and by the Company to the Plan under the Company Matching Contribution Account and Employee Stock Account. Amounts may not be transferred between the Participant Contribution Account, the Company Matching Contribution Account, the Employee Stock Account, or the Rollover Account. Amounts in the Participant Contribution Account, may not be transferred between the After-Tax Option and the Before-Tax Option. An Appropriate Request for Investment Fund transfer may be submitted to the Plan Administrator at any time.

5.3(b) Valuation of Interfund Transfers

The value of the account balances transferred under the interfund transfer provisions shall be determined in the following manner:

If the Participant makes an Appropriate Request for an interfund transfer *prior to* the close of the New York Stock Exchange, (i) transfers from the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the day the Appropriate Request is received, (ii) transfers from the

CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day after the Appropriate Request is received, (iii) transfers to the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the day the Appropriate Request is received, unless the transfer to such funds is from the CEG Common Stock Fund, in which case the value shall be the Closing Price of the funds on the day the proceeds from the sale of the Common Stock are received by the Trustee, and (iv) transfers to the CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day following the day the Appropriate Request is received.

If the Participant makes an Appropriate Request for an interfund transfer *on or after* the close of the New York Stock Exchange, (i) transfers from the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the next business day after the Appropriate Request is received, (ii) transfers from the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day after the Appropriate Request is received, (iii) transfers to the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the next business day after the Appropriate Request is received, unless the transfer to such funds is from the CEG Common Stock Fund, in which case, the value shall be the Closing Price of the funds on the day the proceeds from the sale of the Common Stock are received by the Trustee, and (iv) transfers to the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day following the day the Appropriate Request is received.

5.4 Fractional Shares

The Company does not issue fractional shares of Common Stock. However, to facilitate full investment of monies in the CEG Common Stock Fund, the Plan accounting system allocates fractional shares of Common Stock to Participants' accounts. Participants' fractional shares are aggregated so that only whole shares are actually held by the Plan. The aggregate value of all Participants' whole and allocated fractional shares will not exceed the value of the sum of the shares and cash held by the CEG Common Stock Fund.

Article VI – Vesting

6.1 Participant Contributions

A Participant is 100% vested at all times with respect to amounts in his Participant Contribution Accounts and Rollover Accounts.

6.2 Company Contributions

A Participant is 100% vested at all times with respect to amounts in his Company Matching Contribution Accounts and Employee Stock Accounts.

6.3 Participant's Election to Use Pre-Amendment Vesting Schedule

In the event the Plan is amended to change or modify the Plan's vesting schedule, or the Plan is amended in any way that directly or indirectly affects the computation of the nonforfeitable percentage of the Participant's accrued benefit or if the Plan is deemed amended by an automatic change to or from a top-heavy (see Appendix D) vesting schedule, a Participant with at least three (3) Years of Service as of the date the amendment is adopted or as of the amendment's effective date, may elect to be subject to the pre-amendment vesting schedule. For Participants who do not have at least one (1) Hour of Service in any Plan Year beginning after December 31, 1988, the preceding sentence shall be applied by substituting "five (5) Years of Service" for "three (3) Years of Service." If a Participant fails to make the election described in this Section, then the Participant will be subject to the new vesting schedule. The election of the pre-amendment vesting schedule shall be made by giving written notice to the Plan Administrator during the election period. The election period shall begin on the date such amendment is adopted and shall end no earlier than the latest of the following dates:

(a) The date which is sixty (60) days after the date the Plan amendment is adopted,

(b) The date which is sixty (60) days after the date the Plan amendment becomes effective, or

(c) The date which is sixty (60) days after the date the Participant is issued written notice of the Plan amendment by the Company or Plan Administrator.

Such election shall be made only by an individual who is a Participant at the time such election is made and such election shall be irrevocable. Such Plan amendment shall not reduce the vested percentage of a Participant's accrued benefit as of the later of the date on which such Plan amendment is adopted or the effective date of such Plan amendment.

6.4 Qualified Military Service

If a Participant dies while performing qualified military service (within the meaning of Section 414(u)(5) of the Code), such Participant shall be credited with years of service for the period of his/her qualified military service.

Article VII – Withdrawals

7.1 General

7.1(a) Eligibility

A Participant is eligible to make regular and/or hardship withdrawals from the Plan, subject to the provisions of this Article VII. A Participant will continue to be considered a Participant for purposes of eligibility for withdrawals as long as amounts are held in the Participant's Plan accounts, regardless of such Participant's eligibility to make further contributions to the Plan.

7.1(b) Form and Valuation

Amounts invested in the CEG Common Stock Fund may be withdrawn in whole shares of the Company's Common Stock, with cash in lieu of any fractional share, or, at the Participant's election, the amount may be withdrawn wholly in cash. Withdrawals from the Default Investment Fund and the Other Investment Funds will be made only in cash.

The amounts withdrawn by the Participant will be taken from the Participant's accounts in the order specified in Section 7.4 for regular withdrawals and Section 7.6 for hardship withdrawals and will be subject to any applicable restrictions imposed by the Plan. The Trustee shall sell or purchase securities to meet the Participants' withdrawal requests but must do so over the period of time necessary to insure that such purchases or sales are made in accordance with applicable law, rules and regulations and do not disrupt the trading market for the Common Stock.

The value received by a Participant requesting a withdrawal shall be determined in the following manner:

If the Participant makes an Appropriate Request for a withdrawal *prior to* 4:00 p.m. E.T., (i) withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the day the

Appropriate Request is received; provided, however, that if the withdrawal consists of amounts from the CEG Common Stock Fund, withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received, and (ii) withdrawals from the CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day after the Appropriate Request is received.

If the Participant makes an Appropriate Request for a withdrawal *on or after* 4:00 p.m. E.T., (i) withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received; provided, however, that if the withdrawal consists of amounts from the CEG Common Stock Fund, withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the second business day following receipt of the Appropriate Request, and (ii) withdrawals from the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day following receipt of the Appropriate Request.

In the case of a hardship withdrawal as described in Section 7.5, an Appropriate Request is not treated as having been made for purposes of the above valuation procedures until the Plan Administrator approves the withdrawal for payment.

7.1(c) Maturity

For employees with less than 5 years of service, Participant Contributions and Company Matching Contributions do not mature until 24 months after the date of contributions. For employees with 5 or more years of service, Participant Contributions and Matching Contributions shall mature immediately upon the date of contribution. All contributions made to a Rollover Account shall mature immediately upon the date of contribution. All Supplemental Contributions made prior to October 1, 2004 are mature.

All contributions made to the Employee Stock Account matured prior to October 1, 2004. If a Participant dies while performing qualified military service (within the meaning of Section 414(u)(5) of the Code), such Participant shall be credited with years of service for the period of his/her qualified military service

7.2 Regular Withdrawals

A Participant may make a regular withdrawal at any time by submitting an Appropriate Request to the Plan Administrator. A regular withdrawal is a withdrawal other than a hardship withdrawal and does not include distributions upon termination of employment as described in Article VIII.

Each regular withdrawal request received by the Plan Administrator will be paid out as soon as practicable after the request is received.

7.3 Restrictions on Regular Withdrawals

7.3(a) Regular Withdrawal of Contributions Under the Before-Tax Option

Before-Tax Option contributions, whether Basic or Supplemental, and related earnings may not be paid out of the Plan as part of a regular withdrawal unless the Participant is at least age 59-1/2, has retired, has been placed on long-term disability, or has terminated employment for any other reason. A Participant on a leave of absence is not considered to have terminated employment. The source of the amounts withdrawn from the Plan by a Participant who is at least age 59-1/2 or who has retired, been placed on long-term disability, or terminated employment for any other reason, must conform to the order of withdrawal specified in Section 7.4.

7.3(b) Consequences of Withdrawals of Unmatured Participant Contributions

If, in following the order of withdrawal specified in Section 7.4, any unmatured Participant Contributions are withdrawn, the Participant will be suspended from making contributions to the Plan under the After-Tax Option and the Before-Tax Option for (i) six (6) months following the month in which the Appropriate Request for the regular withdrawal is received by the Plan Administrator, if such withdrawal is made after September 30, 2004, and (ii) twelve (12) months following the month in which the Appropriate Request for the regular withdrawal is received by the Plan Administrator, if such withdrawal is made before October 1, 2004. There are no other penalties or restrictions under the Plan for withdrawing amounts that are eligible for withdrawal.

7.3(c) Withdrawals of Certain Other Unmatured Contributions

Withdrawals of unmatured contributions and related earnings from a Participant's Company Matching Contribution Account are not permitted under the Plan. The restriction on withdrawal lapses once these contributions mature.

7.4 Source of Regular Withdrawals

A Participant's regular withdrawals from the Plan will be taken from the Participant's accounts in the order listed below. For each level in the order of withdrawal, the entire account balance must be exhausted before amounts may be withdrawn from the next level. The meaning of matured and unmatured accounts as used below relates to the status of the contributions as explained in Section 7.1(c). Unless specifically indicated otherwise, an account includes both contributions and earnings thereon.

First	After-Tax Option Account with respect to Participant Contributions made prior to January 1, 1987, followed by earnings thereon.
Second	Matured After-Tax Option Account with respect to Participant Contributions made after December 31, 1986, followed by earnings thereon.
Third	Rollover Account.

Fourth	Employee Stock Account. Withdrawals from the Employee Stock Account will be made first from the portion of the account representing the Participant's investment in the account (i.e., amounts transferred from the terminated Baltimore Gas and Electric Company Employee Stock Ownership Plan that consist of after-tax contributions made by employees to such plan), and then from the remainder of the account.
Fifth	Matured Company Matching Contribution Account.
Sixth	Matured Before-Tax Option Account, but only if the Participant has reached age 59-1/2, retired, been placed on long-term disability or terminated employment for any other reason.
Seventh	Unmatured After-Tax Option Account with respect to Participant Contributions, followed by earnings thereon.
Eighth	Unmatured Before-Tax Option Account with respect to Participant Contributions, but only if the Participant has reached age 59-1/2, retired, been placed on long-term disability or terminated employment for any other reason.

The Participant will be permitted to make a regular withdrawal only to the extent funds eligible for withdrawal are available in the Participant's Plan accounts.

Withdrawals will be made pro rata in proportion to the Participant's respective investment in each Investment Fund under the account applicable to the level of withdrawal.

7.5 Hardship Withdrawals

7.5(a) General

A Participant will be eligible to receive a withdrawal under the hardship withdrawal provisions of the Plan if the Participant submits an Appropriate Request to the Plan Administrator and receives the Plan Administrator's express sanction and approval for the withdrawal. To obtain approval, the Participant will be required to demonstrate that the hardship withdrawal is necessary to satisfy an immediate and heavy financial need.

Because a Participant must withdraw all amounts available under the regular withdrawal provisions of the Plan and obtain any available loans under the Plan's loan provisions, prior to withdrawing amounts under the hardship withdrawal provisions, hardship withdrawals are limited to the Participant's contributions under the Before-Tax Option and earnings thereon which are not otherwise available as regular withdrawals or loans. However, earnings on Before-Tax Option contributions are available for hardship withdrawal only if allocated to the Participant's account as of December 31, 1988.

Following receipt of a hardship withdrawal, the Participant will be suspended from making contributions to the Plan under the After-Tax Option and the Before-Tax Option and to certain other plans of the Employer, as defined in Treasury Regulation Section 1.401(k)-1(d)(3)(iv)(F), for six (6) full months beginning with the first Payroll Period in the month following the month in which the hardship withdrawal is approved for payment by the Plan Administrator. A hardship withdrawal will be paid out as soon as practicable after Plan Administrator approval.

7.5(b) Immediate and Heavy Financial Need

In order to receive a hardship withdrawal, the Participant must demonstrate an immediate and heavy financial need. The following financial needs will automatically qualify as immediate and heavy.

1) Medical expenses described in Code Section 213(d) which have been previously incurred or are necessary to obtain medical care by the Participant, the Participant's Spouse, or any dependents of the Participant as defined in Code Section 152, without regard to subsections (b)(1), (b)(2), and (d)(1)(B) thereof.

2) The purchase (excluding mortgage payments) of a principal residence for the Participant.

3) The payment of tuition and related educational fees for the next twelve (12) months of post-secondary education for the Participant, the Participant's Spouse, or dependents as defined in Code section 152, without regard to subsections (b)(1), (b)(2), and (d)(1)(B) thereof.

4) Mortgage payments or rental payments that must be paid to prevent foreclosure on the mortgage of the Participant's principal residence or eviction of the Participant from his principal residence.

5) Certain other specified events that are deemed to be of an immediate and heavy financial need as determined by the Internal Revenue Service and published in revenue rulings, notices, and other documents of general applicability.

Other financial needs may qualify as immediate and heavy, based on all relevant facts and circumstances and subject to the approval of the Plan Administrator. Generally, for example, the need to pay funeral expenses for a family member may qualify as an immediate and heavy financial need.

The amount of an immediate and heavy financial need may include amounts necessary to pay any federal, state, or local income taxes or penalties reasonably anticipated to result from the hardship withdrawal.

It is the intent of the Plan that the definition of an "immediate and heavy financial need" will conform to the meaning of the term under the provisions of Treasury Regulation Section 1.401(k)-1(d)(3).

7.5(c) Withdrawal Deemed Necessary to Satisfy an Immediate and Heavy Financial Need – Requirements

After a Participant demonstrates that an immediate and heavy financial need exists, the Participant must also demonstrate that a hardship withdrawal from the Plan is necessary to satisfy that need.

Hardship withdrawals under the Plan will automatically be deemed necessary to satisfy an immediate and heavy financial need if all of the following requirements are met.

1) The withdrawal does not exceed the amount of the immediate and heavy financial need of the Participant.

2) The Participant has elected to receive all dividend distributions currently available under the Plan pursuant to Section 8.5(a), and has obtained all withdrawals, other than hardship withdrawals, and all nontaxable loans currently available under the Plan.

3) The Participant's contributions under the After-Tax and Before-Tax Options of the Plan and contributions to certain other plans of the Employer, as defined in Treasury Regulation Section 1.401(k)-1(d)(3)(iv)(F), are suspended for six (6) months following the month of receipt of the hardship withdrawal.

Notwithstanding the above, the Plan Administrator may, at his discretion, determine that a hardship withdrawal is necessary to satisfy an immediate and heavy financial need after a review of all relevant facts and circumstances.

It is the intent of the Plan that the withdrawals deemed necessary to satisfy the immediate and heavy financial need under this Section 7.5(c), will conform to the withdrawals deemed to satisfy this need under Treasury Regulation Section 1.401(k)-1(d)(3).

7.6 Source of Hardship Withdrawals

A Participant's hardship withdrawals from the Plan will be taken from the Participant's Before-Tax Option Account, but only after all available amounts have been withdrawn under the regular withdrawal provisions of the Plan and all available nontaxable loans have been taken under the loan provisions of the Plan. For purposes of this Section, the Before-Tax Option Account includes contributions and earnings allocated thereon as of December 31, 1988. Earnings allocated to the Before-Tax Option Account after December 31, 1988 are not available for hardship withdrawal and, accordingly, are excluded therefrom.

Qualified Nonelective Contributions and earnings thereon are not available for hardship withdrawal and, accordingly, are excluded therefrom.

The Participant will be permitted to make a hardship withdrawal only to the extent funds eligible for withdrawal are available in the Participant's Before-Tax Option Account.

Hardship withdrawals will be made pro rata in proportion to the Participant's respective investment in each Investment Fund under the Before-Tax Option Account.

Unmatured amounts not available for regular withdrawal under Section 7.3(c) will also not be available to the Participant for any hardship withdrawal.

7.7 Direct Rollover of Withdrawals

Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this Section, a Distributee may elect, at the time and manner prescribed by the Plan Administrator, to have any portion of a withdrawal from the Plan that is an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover.

7.8 <u>In-Service Distributions for Active Duty Members of the Uniformed Services.</u>

An individual who is on active duty for more than 30 days in accordance with Section 414(u)(12)(B) of the Code is treated as having been severed from employment during such period and may elect a distribution in accordance with and subject to the limitations of Section 414(u)(12)(B) of the Code. If a Participant elects a 30-day deemed distribution period, the Participant's right to make contributions under the After-Tax and Before-Tax Options following such distribution and while on leave must be suspended for a six-month period after the distribution.

Article VIII – Distributions

8.1 Eligibility

A Participant will continue to be considered a Participant for purposes of eligibility for distributions as long as amounts are held in the Participant's Plan accounts, regardless of such Participant's eligibility to make further contributions to the Plan.

A Participant is eligible to receive final distributions of all amounts in the Plan when the Participant either reaches age 70-1/2, retires, is placed on long-term disability, or terminates employment for any other reason. If a Participant dies, the Participant's beneficiary is entitled to any undistributed amounts from the Plan, as provided in Section 8.7. A Participant on a leave of absence is not considered to have terminated employment and will not be entitled to a distribution from the Plan under the provisions of this Article VIII.

8.2 Required Distributions

8.2(a) Distributions After Attaining Age 70-1/2

A Participant's entire Plan balance shall be distributed, or installment payments shall begin, not later than April 1st of the calendar year following the calendar year in which the Participant attains age 70-1/2, unless such Participant is employed by an Employer (in which case such distribution or installment payments shall commence upon employment termination). However, if there ever is a Participant who is a 5% owner (as defined in Code Section 416(i)), payment must commence no later than April 1st of the Plan Year after the Plan Year in which such Participant attains age 70-1/2, even if the Participant is still employed.

8.2(b) Mandatory Distribution for Plan Balances of $1,000 or less

A Participant who retires, is placed on long-term disability, or terminates employment for any other reason will automatically receive a final lump-sum distribution of all amounts held in the Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account, if the aggregate value of the accounts is $1,000 or less as of the end of the calendar month in which retirement, placement on long-term disability, or termination for any other reason occurs. The aggregate value of a Participant's Plan accounts will be determined in accordance with the Trust Agreement and will include the value of any outstanding Plan loans to the Participant. Any distributions from a Participant's accounts that are invested in the CEG Common Stock Fund will be made in the form of a lump-sum cash payment in lieu of shares of Common Stock, unless the Participant elects a distribution of Common Stock representing investments in the CEG Common Stock Fund by filing an Appropriate Request with the Plan Administrator. A distribution under this Section 8.2(b) will be made within 90 days after the end of the month in which retirement, placement on long-term disability, or termination for any other reason occurs.

8.3 Distributions Elected by Participant

8.3(a) Time of Distribution

Participants eligible to receive final distributions from the Plan and who are not subject to the required distribution provisions of Section 8.2 may elect a distribution by submitting an Appropriate Request with the Plan Administrator. Distributions will commence as soon as practicable after the Appropriate Request is received by the Plan Administrator.

The Participant's final distribution will be made within sixty (60) days after the later of the end of the Plan Year in which: (i) the Participant attains age 65, (ii) the Participant ceases active employment, or (iii) the tenth (10th) anniversary of the year in which the Participant's participation in the Plan occurs. Notwithstanding the preceding sentence, a distribution will not be made unless the Participant submits an Appropriate Request for a distribution with the Plan Administrator. In any case, distributions must begin by the date prescribed in Section 8.2(a).

8.3(b) Method of Distribution

Participants who are not subject to the mandatory distribution requirements of Section 8.2(b) may elect to receive distributions as lump-sum payments, or as installment payments as provided in Section 8.4(c) made over a period not to exceed ten (10) years. Partial payments may also be made from time to time as requested under the withdrawal provisions of Article VII.

8.3(c) Required Minimum Distributions

Notwithstanding any other provision in the Plan to the contrary, distributions under the Plan shall comply with the requirements of Code section 401(a)(9) (including the incidental death benefit requirements of Code section 401(a)(9)(G)) and the regulations thereunder. Notwithstanding anything in the Plan to the contrary, a Participant or beneficiary who would have been required to receive required minimum distributions for 2009 but for the enactment of Section 401(a)(9)(H) of the Code ('2009 RMDs'), and who would have satisfied that requirement by receiving distributions that are (1) equal to the 2009 RMDs or (2) one or more payments in a series of substantially equal distributions (that include the 2009 RMDs) made at least annually and expected to last for the life (or life expectancy) of the Participant, the joint lives (or joint life expectancy) of the Particpant and the beneficiary, or for a period of at least 10 years ('Extended RMDs'), will receive those distributions for 2009. In addition, solely for purposes of applying the Direct Rollover provisions of the Plan, 2009 RMDs and Extended RMDs will not be treated as Eligible Rollover distributions.

8.4 Form and Valuation of Distribution

8.4(a) CEG Common Stock Fund

Except as provided in Section 8.2(b) under the mandatory distribution requirement or Section 8.4(c) under the installment payment option, any distributions from a Participant Contribution Account, Company Matching Account, Employee Stock Account, or Rollover Account that are invested in the CEG Common Stock Fund will be made in a lump-sum payment constituting shares of Common Stock with cash paid in lieu of fractional shares.

The portion of the distribution representing investments in the CEG Common Stock Fund may, at the election of the Participant, be received entirely in cash in lieu of shares of Common Stock upon submitting an Appropriate Request with the Plan Administrator.

8.4(b) Default Investment Fund and Other Investment Funds

Except as provided in Section 8.4(c) under the installment payment option, any distributions from a Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, or Rollover Account that are invested in the Default Investment Fund and/or the Other Investment Funds will be made in the form of a lump-sum cash payment.

8.4(c) Installment Payment Option

Participants who are not subject to the mandatory distribution requirements of Section 8.2(b) and who are retired, have been placed on long-term disability, or terminated employment for any other reason, may elect to receive their distributions in annual, quarterly, or monthly installments over a period not to exceed ten (10) years. The election to receive such installments must be made prior to receiving a distribution and by means of an Appropriate Request submitted with the Plan Administrator.

Participants who have elected the installment payment option and selected an installment payment period may change the number of years, quarters, or months over which installments will be made at any time after the installment payments have commenced, provided that such change will not result in an installment payment period in excess of ten (10) years from the date the installments began. The election to change the installment payment period is made by submitting an Appropriate Request with the Plan Administrator. Any change in the installment payment period will be effective as soon as practicable following receipt of the Appropriate Request by the Plan Administrator.

A Participant who has elected the installment payment option may, at any time, submit an Appropriate Request with the Plan Administrator to receive a lump-sum payment of the remaining balance in the Participant's accounts.

The amounts included in installment payments to a Participant will be taken from the Participant's Plan accounts in the same order specified in Section 7.4 for regular withdrawals. Unmatured Company Matching Contribution Account amounts remaining in the Participant's accounts after such ordering rules are applied are included in installment payments. The meaning of unmatured accounts relates to the status of contributions as explained in Section 7.1(c). Unless specifically indicated otherwise, an account includes both contributions and earnings thereon.

Amounts invested in the CEG Common Stock Fund may be received under the installment payment option either in whole shares of the Company's Common Stock with cash in lieu of any fractional share, or, at the Participant's election, in cash. A Participant's election to receive cash or not to receive cash for amounts invested in the CEG Common Stock Fund will apply to all installment payments made to the Participant subsequent to such election, unless the Participant submits an Appropriate Request with the Plan Administrator prior to the installment payment date requesting that the Participant's election be changed.

Installment payments that consist of amounts from the Default Investment Fund and the Other Investment Funds will be made only in cash.

Amounts included in installment payments will be withdrawn from a Participant's investment funds pro rata in proportion to the Participant's respective investment in each Investment Fund under the account applicable to the level of installment payment.

8.4(d) Valuation of Distributions

The value received by a Participant requesting a lump-sum distribution shall be determined in the following manner:

If the Participant makes an Appropriate Request for a distribution *prior to* 4:00 p.m. E.T., (i) distributions from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the day the Appropriate Request is received; provided, however, that if the distribution consists of amounts from the CEG Common Stock Fund, distributions from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received, and (ii) distributions from the CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day after the Appropriate Request is received.

If the Participant makes an Appropriate Request for a distribution *on or after 4:00* p.m. E.T., (i) distributions from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received; provided, however, that if the distribution consists of amounts from the CEG Common Stock Fund, distributions from the Default Investment Fund and Other Investment Funds shall be valued based on

Closing Price for such funds on the second business day following receipt of the Appropriate Request, and (ii) distributions from the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day following receipt of the Appropriate Request.

For a Participant electing the installment distribution option, the value received for the first installment payment shall be determined in accordance with the above valuation procedures. For installment payments in subsequent years, the value received shall be determined in accordance with the above valuation procedures.

The valuation procedures described above shall be applied by substituting the term “Plan Administrator action” for each place the term “Appropriate Request” appears, in the case of (i) Participants subject to the required distribution provisions of Section 8.2, and (ii) beneficiaries who fail to elect an earlier distribution as described in Section 8.7(a).

8.5 Employee Stock Account Dividend Distributions

This Section 8.5 applies through, but is no longer effective after, the Common Stock dividend payment on January 1, 2002.

Any dividends declared and paid on shares of Common Stock in the Employee Stock Account in the CEG Common Stock Fund held by the Trustee pursuant to the Plan shall be invested by the Trustee pursuant to the Trust Agreement in interest bearing accounts. After the final dividend payment in each year has been made by the Company, the Trustee will distribute to each Participant by not later than December 31st of that year the dividend amounts declared and paid on the shares of Common Stock allocated to the Participant’s Employee Stock Account in the CEG Common Stock Fund. The Trustee shall invest, no less frequently than quarterly, any interest earned on such dividends prior to their distribution, in shares of Common Stock, and allocate such shares to the Participant’s Employee Stock Account in the CEG Common Stock Fund.

When a Participant receives final distributions of all amounts in the Plan allocated to his accounts, any additional dividends which have been declared and paid on shares of Common Stock in the Employee Stock Account and any related interest in the CEG Common Stock Fund which has not yet been distributed under the provisions of this Section 8.5, will be distributed in cash at the same time as the distribution of the shares of Common Stock in the Participant's Employee Stock Account in the CEG Common Stock Fund.

8.5(a) CEG Common Stock Fund Employee Election

Effective February 1, 2006, any dividend paid with respect to shares of the CEG Common Stock Fund allocated to the Participant's accounts as of the record of such dividend will be, as elected by the Participant prior to the payment date (1) distributed in cash to the Participant as soon as administratively practicable following the date such dividend is paid by the Company or (2) retained by the Trustee and reinvested in Company stock for credit to the Participant's account in the CEG Common Stock Fund. The amount distributed to the Participant pursuant to clause (1) of the preceding sentence shall be the lesser of (A) the original amount of the dividends attributable to that Participant and (B) the amount of such dividends as adjusted for any investment losses while held in the Trust or reduced for any withholdings. In accordance with such procedures as the Plan Administrator may provide, a Participant shall be given a reasonable opportunity to make an election under this Section 8.5(a) before the beginning of each quarter of the Company's taxable year with respect to dividends paid in such quarter. A Participant may have only one election in effect for his or her account at any time (and may not make separate elections with respect to the different portions of his or her account). If a Participant who has previously made a timely election under this Section 8.5(a) does not make a new election with respect to dividends paid in a subsequent period, the Participant's prior election shall remain in effect for such subsequent period (and shall apply to all dividends paid on Company Stock during such period with respect to which an election is offered). In the absence of a timely election, the Participant shall be deemed to have elected to have the dividends with respect to which an election is offered accumulated in his or her account and reinvested in Company Stock.

8.6 Unlocated Participants

If and when the balance in a Participant's account(s) under the Plan becomes payable and the Plan Administrator is unable to locate a Participant or his designated beneficiary or beneficiaries to whom such amounts are payable, the Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account of the Participant will be closed after three (3) years from the date amounts in the Plan first become payable under Sections 8.2, 8.3, or 8.7. The balances in the closed accounts will be forfeited and thereafter applied to reduce Company contributions to the Plan. However, if the Participant or his designated beneficiary or beneficiaries subsequently files a proper claim with the Plan Administrator for such amounts, and the claim is filed prior to the termination of the Plan, the Company will restore the Participant's accounts to the balances that existed when they were closed.

Once the amounts have been restored, the balances will be available for distribution in accordance with the distribution provisions of the Plan.

8.7 Distribution Upon Death of Participant

8.7(a) Payment to Beneficiary

When a Participant dies, the deceased Participant's beneficiary is entitled to a distribution of all amounts held in the Participant's accounts.

Unless the Participant's beneficiary requests an earlier distribution to be made or commenced as soon as possible after an Appropriate Request is submitted to the Plan Administrator, all amounts held in the Participant's accounts will be distributed to the beneficiary within sixty (60) days after the end of the Plan Year in which the Participant dies.

Amounts held in the CEG Common Stock Fund will be paid to the Participant's beneficiary in Common Stock or in cash in accordance with the provisions of Section 8.4(a). If the beneficiary wishes to receive the distribution in cash, an Appropriate Request must be submitted by the beneficiary to the Plan Administrator. Amounts held in the Default Investment Fund and the Other Investment Funds will be paid to the Participant's beneficiary in the form of a lump-sum cash payment in accordance with the provisions of Section 8.4(b). A beneficiary may not elect to receive the distribution under the installment payment option.

If a Participant elected a distribution under the installment payment option provisions of Section 8.4(c) and dies during the installment payment period, or before the installment payment period begins, the remaining balance in the Investment Funds that was to be paid out under the installment payment option will be paid to the Participant's beneficiary in a lump-sum. Any amounts remaining in the CEG Common Stock Fund will be paid to the beneficiary in Common Stock or in cash in accordance with the Participant's most recent election under Section 8.4(c). If the beneficiary wishes to receive the distribution in a different form than that which will be received under the Participant's most recent election, an Appropriate Request must be submitted by the beneficiary with the Plan Administrator. Amounts remaining in the Default Investment Fund and the Other Investment Funds will be paid to the Participant's beneficiary in the form of a lump-sum cash payment.

In the event any Participant is deceased at the time of a dividend distribution from the Participant's Employee Stock Account paid under the dividend distribution provisions of Section 8.5(b), the distribution will be made to the Participant's beneficiary, as determined in accordance with this Section 8.7(a).

In the case of a Participant who dies while performing qualified military service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of qualified military service) provided under the Plan had the Participant resumed and then terminated employment on account of death.

8.7(b) Designation of Beneficiaries

Any interests in the Plan which have not been distributed to a Participant prior to his death will be distributed to the Participant’s surviving Spouse, unless the Participant and his Spouse have jointly designated some other beneficiary or beneficiaries. A joint designation must be made on a special form provided by the Plan Administrator and duly witnessed by a notary public.

The consent of the Spouse of the Participant will not be required if it is established to the satisfaction of the Plan Administrator that the consent of the Spouse may not be obtained because there is no Spouse, because the Spouse cannot be located, or because of such other circumstances as the Secretary of the Treasury may by regulations prescribe. Any consent of a Spouse (or establishment that the consent of a Spouse may not be obtained) as provided above shall be effective only with respect to such Spouse. For purposes of this Section 8.7(b), the Spouse or surviving Spouse of the Participant is the Spouse at the time of the Participant’s death, except that a former Spouse will be treated as the Spouse or surviving Spouse to the extent provided under a qualified domestic relations order as described in Code Section 414(p). The designation of a beneficiary may be changed at any time by the proper completion and forwarding to the Plan Administrator of the beneficiary-designation form.

If a Participant dies and does not leave a surviving Spouse, any undistributed interests will be paid to any beneficiary or beneficiaries that the Participant has designated on the beneficiary-designation form provided by the Plan Administrator. If a Participant dies and leaves no surviving Spouse and no beneficiary is effectively designated in connection with the benefits due under the Plan, the benefits provided under the Plan will be distributed to any effectively designated beneficiary (as indicated on the life insurance beneficiary-designation form) of any Company-sponsored life insurance of the Participant. If there is no beneficiary effectively designated to take the proceeds of such life insurance, the benefits due under the Plan shall be distributed to the personal representative, if any, of the deceased Participant. In any case where the exact intention of a Participant is in doubt in connection with the designation of a beneficiary, the Plan Administrator shall have full authority to determine such probable intention. The effectiveness of the Participant's beneficiary designation and the Plan Administrator's determination of the intention of the Participant shall be final and binding upon all parties.

The Plan Administrator may require such proper proof of death and such evidence of the right of any person to receive payment of the value of the account of a deceased Participant as the Plan Administrator may deem desirable. The Plan Administrator's determination of death and of the right of any person to receive payment shall be conclusive.

8.8 Direct Rollover of Distributions

Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this Section, a Distributee may elect, at the time and manner prescribed by the Plan Administrator, to have any portion of a distribution from the Plan that is an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover, including, for distributions made after December 31, 2009, an individual retirement plan described in Code Section 408(a) or (b) for non-spouse beneficiary Distributees as described in Code Section 402(c)(11). Effective for distributions made after October 30, 2009 and subject to the provisions of Section 3.3 of the Plan, an Eligible Rollover Distribution that includes amounts that are not includable in gross income may be transferred pursuant to this Section 8.8 if the qualified trust or annuity contract described in section 403(b) of the

Code receiving such Direct Rollover separately accounts for the portions of the distribution that are and are not includable in gross income. Effective for calendar years beginning on or after December 31, 2008, solely for purposes of applying the direct rollover provisions of the Plan, 2009 required minimum distributions pursuant to Code Section 401(a)(9)(H) and extended 2009 required minimum distributions will be treated as Eligible Rollover Distributions in 2009.

8.9 Qualified Reservist Distributions

The Plan permits a Participant to elect a Qualified Reservist Distribution. For purposes of this Section 8.9, a Qualified Reservist Distribution is any distribution to an individual who is ordered or called to active duty after September 11, 2001, if: (i) the distribution is from amounts attributable to elective deferrals including After-Tax and Before-Tax Options; (ii) the individual was (by reason of being a member of a reserve component, as defined in Section 101 of Title 37, United States Code) ordered or called to active duty for a period in excess of 179 days or for an indefinite period; and (iii) the Plan makes the distribution during the period beginning on the date of such order or call, and ending at the close of the active duty period. A Participant that meets the requirements for a Qualified Reservist Distribution under this Section 8.9 will be treated as taking a distribution under this Section 8.9 regardless of whether such Participant is also entitled to distribution under Section 7.8.

Article IX – Loans to Participants

9.1 General

A Participant will continue to be considered a Participant for purposes of this Article IX as long as the Participant continues to be a Party in Interest.

At the direction of the Plan Administrator, the Trustee may make loans to Participants from the Plan. Plan loans will in all cases meet the following requirements.

a) Loans will be available to all Participants on a reasonably equivalent basis.

b) Loans will not be made available to Participants who are Highly Compensated Employees in an amount greater than the amount made available to other Participants.

c) Loans will be made in accordance with all other specific provisions regarding Participant Loans under the Plan.

d) Loans will bear a reasonable rate of interest as provided under Section 9.3.

e) Loans will be adequately secured as provided under Section 9.4.

9.2 Amount

A Participant may apply for a loan from his account balance in the Plan subject to the limitations and other provisions of this Article IX or as may be adopted by the Plan Administrator. Application for loans is made by submitting an Appropriate Request with the Plan Administrator. The Plan Administrator's action in approving or disapproving any application for a loan shall be final. The Plan Administrator, in his sole discretion, may direct the Trustee to lend a Participant an amount which does not exceed fifty percent (50%) of the Participant's Total Account Balance; provided, however, that the minimum loan amount shall be $1,000 and the maximum loan amount shall be $50,000.

For purposes of determining whether a loan exceeds $50,000, such loan shall be added to the highest outstanding balance of all other loans from the Plan or any other plans of the Employer during the twelve-month period preceding the date on which the loan is made (i.e., the date of the check). Participants making application for a loan from the Plan may be required to demonstrate their creditworthiness to the satisfaction of the Plan Administrator.

A Participant may have no more than two loans outstanding at a time. A Participant who has an existing loan and qualifies for a hardship withdrawal may be required to obtain a second loan pursuant to Section 7.5(c).

Loan proceeds may not be used for the purpose of investing in stocks, securities, or other similar or intangible investments. All loans shall be subject to the approval of the Plan Administrator, or his designee, who shall review each application for a loan. The Plan Administrator shall adopt such rules, procedures and documents as he may deem advisable in regard to the granting of loans, provided such rules, procedures, and documents are consistent with the provisions of this Article IX.

9.3 Reasonable Rate of Interest

Each loan will bear a reasonable rate of interest on the unpaid balance during the term of the loan which (except as provided in Section 9.14) will be equal to the prime rate plus one percent (1%), as reported in the Eastern Edition of the Wall Street Journal on the last day of the month preceding the month in which the Participant submits an Appropriate Request for a loan with the Plan Administrator. The interest rate on a loan will remain in effect for the term of the loan.

9.4 Adequate Security

The Participant shall grant to the Trustee a security interest in the loan account to the extent of his outstanding principal loan balance. The security interest will secure repayment of the loan and will remain in effect until the loan, together with accrued interest, is paid in full. The amounts in a Participant's loan account used to secure the loan balance are not available for withdrawal or distribution.

9.5 Source of Funds

Each loan shall be treated as a separate investment of the portion of the Participant's Plan account balance borrowed and the Plan Administrator shall direct the Trustee to reduce the Participant's Plan account balance by an amount equal to the amount borrowed. A loan account will be established for the Participant reflecting the amount of his loan. The money borrowed will be taken from the Participant's Plan accounts in the order shown below. The meaning of matured and unmatured accounts as used below relates to the status of contributions as explained in Section 7.1(c). Unless specifically indicated otherwise, an account includes both contributions and earnings thereon. Loan amounts will be taken from a Participant's Investment Funds on a pro rata basis.

First	Before-Tax Option Account.
Second	Unmatured After-Tax Option Account.
Third	Company Matching Contributions Account.
Fourth	Employee Stock Account, <u>except</u> the Participant's investment in the account.
Fifth	Employee Stock Account representing the Participant's investment in the account.
Sixth	Rollover Account.
Seventh	Matured After-Tax Option Account.

9.6 Valuation of Loans

The value received by a Participant requesting a loan shall be determined in accordance with this Section. Loans will be processed as soon as practicable after the Participant's properly executed loan agreement is received by the Plan Administrator. Loans from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the day the loan is processed. Loans from the CEG Common Stock Fund shall be valued based on the Transaction Price on the day the loan is processed.

9.7 Loan Repayment

For Participants who are active Employees, payments of principal and interest on the loan must be made by payroll deduction, whichever is applicable. Participants who are not active Employees are required to make regular monthly payments of principal and interest on the loan by personal check or money order payable to the Company or its designee, as directed by the Plan Administrator. Each loan shall by its terms require that repayment (principal and interest) be amortized in level payments over a loan term that is arrived at by mutual agreement between the Plan Administrator and the Participant. In no event (other than as provided under Section 9.14), however, will the term of the loan exceed five (5) years unless the loan is to be used to acquire a Participant's principal residence, in which case, the term of the loan may not exceed thirty (30) years.

A Participant may repay the entire outstanding balance of a loan, plus any accrued interest, at any time by personal check or money order made payable to the Plan or the Trustee. Loan repayments constituting a repayment of principal will be allocated to the Participant's Plan accounts in the reverse order from which borrowed. Within the accounts, principal repayments will be allocated among the various Investment Funds in accordance with the Participant's most recent investment directions. The interest portion of the loan repayment will be allocated to the Participant's Plan accounts on a pro rata basis in accordance with the amounts originally withdrawn from the Participant's accounts in order to fund the loan. Within such accounts, interest payments will be allocated among the various Investment Funds in accordance with the Participant's most recent investment directions.

9.8 Default

A default occurs if a Participant fails to make a loan payment within 90 days after its due date or a beneficiary fails to continue the loan repayments or to repay the loan in full within 90 days after the payment's due date. Upon the occurrence of a default, the Participant or beneficiary, as the case may be, will be subject to any legal remedies available for collecting the debt. In addition, the outstanding principal amount of the loan may be treated as a distribution, reportable to the Internal Revenue Service. If a Participant defaults on a loan while an active Employee, the Participant will be suspended from making contributions to, and taking loans from, the Plan for two (2) years from the date of default. If a Participant who is not an active Employee defaults on a loan, the Participant will be unable to take loans from the Plan for two (2) years from the date of default. The Plan Administrator shall have the discretion to allow additional time for repayment, subject to the requirements of Code Section 72(p) and the Treasury Regulations promulgated thereunder.

9.9 Death of a Participant

If a Participant dies prior to repaying a loan, the outstanding loan principal will be treated, and reported to the Internal Revenue Service, as a distribution to the beneficiary unless the beneficiary elects either to continue to make monthly loan repayments until the Plan balance is distributed to the beneficiary under the provisions of Section 8.7(a), or to repay the outstanding principal balance, plus accrued interest, within 90 days after the last loan repayment was made.

9.10 Loan Agreement and Amendments

A Participant's loan will be evidenced by a loan agreement, which will include a promissory note and security agreement and payroll deduction authorization, if applicable. Participants will be required to execute a document, or otherwise evidence their agreement electronically (in such form and manner as the Plan Administrator shall specify), specifying the terms of the loan. Amendments to the loan terms must be authorized by both parties; provided, however, that amendments required as a result of a change to any applicable law or regulation or the issuance of any new ruling or interpretation by any governmental agency may be made unilaterally to the Plan and the loan agreement upon written notice to the Participant. The loan is at all times subject to such other conditions as may be required by the Internal Revenue Service or any other governmental agency.

9.11 Assignment of Interest

A Participant cannot assign his loan or obligation to repay his loan to any other person, corporation, or entity. Any attempted assignment of a Plan loan or obligation to repay will be void.

9.12 Prohibited Transactions

No loan shall be made unless such loan is exempt from the tax imposed on prohibited transactions by Code Section 4975.

9.13 Loan Initiation Fees

A Participant who applies for a loan will be charged a loan initiation fee, as determined from time to time by the Plan Administrator, which will be deducted from the Participant's Plan account balance in the same manner set forth in Section 9.5.

9.14 Leaves of Absence

9.14(a) Non-Military Leaves of Absence

Participants who are on an approved leave of absence other than a Military Leave of Absence must continue to make loan repayments during such leave. Interest continues to accrue during such leave of absence at the original interest rate.

9.14(b) Military Leaves of Absence

Participants may elect to discontinue making loan repayments during a Military Leave of Absence, in which case the loan termination date shall be extended for a period equal to the length of the Military Leave of Absence (not to exceed the number of months of missed repayments). In addition, the loan interest rate for any Participant who is on a Military Leave of Absence and who does not elect otherwise shall, while the Participant is on such Military Leave of Absence, be the lesser of 6% per annum or the original interest rate.

Article X – Plan Administration

10.1 Plan Administrator

The Plan will be administered by the Director – Benefits of the Company (or the position succeeding to that function) as a fiduciary and as Plan Administrator. The Plan Administrator shall discharge his duties for the exclusive benefit of Participants and their beneficiaries. The Plan Administrator shall be authorized to delegate his duties and responsibilities hereunder.

10.2 Rules and Regulations

The Plan Administrator may adopt such rules and regulations as he may deem necessary or advisable for the administration of the Plan on a consistent and non-discriminatory basis.

10.3 Powers and Duties of the Plan Administrator

The Plan Administrator shall administer the Plan in accordance with its provisions and shall have all powers necessary for that purpose, including, but not limited to, the power (i) to interpret the Plan, (ii) to resolve all questions concerning eligibility for benefits or loans under the Plan and to require any person to furnish such information as he may reasonably request as a condition to receiving any benefit or loan under the Plan, (iii) to compute or cause to be computed the amount of benefits payable or loans available here under to Participants or their beneficiaries, and (iv) to direct the Trustee concerning all payments that shall be made out of the Investment Funds pursuant to the provisions of the Plan. The Plan Administrator may, in writing, delegate any part of his responsibilities and duties (including but not limited to the approval of loans to Participants) to one or more designees and may withdraw such authority by a subsequent writing.

10.4 Records and Reports

The Plan Administrator shall cause to be furnished to each Participant, on at least a semiannual basis and upon any withdrawal, distribution, or loan to him, a detailed report, indicating the current value of the Participant's interest in the Plan, as well as any other reports now or hereafter required by law to be furnished to each Participant or any regulatory agency.

10.5 Procedure for Review of Claim

10.5(a) Denial of Claim

If after a Participant makes a claim for benefits by submitting an Appropriate Request, such claim is denied in full or in part, the Plan Administrator shall, within ninety (90) days after receipt of the claim, provide the Participant (at the Participant's last address appearing on the records of the Plan) with written notice by mail, in language calculated to be understood by the Participant, of the denial of the claim stating (i) the specific reasons for the denial, (ii) the specific references to pertinent Plan provisions on which the denial is based, (iii) any additional material or information necessary for the Participant to resubmit the claim, including an explanation of why such material or information is necessary, and (iv) an explanation of the claims appeal procedure, including a statement of the Participant's right to bring a civil action under Section 502(a) of ERISA following an adverse benefit determination on review. If special circumstances require an extension of time to process the claim, within 90 days after receipt of the claim, the Plan Administrator shall provide the Participant with written notice by mail specifying the reasons for the need for an extension of time, and a date by which he expects to render a decision. In that event, the initial 90-day period for notice of denial shall be extended by an additional 90 days.

10.5(b) Appeal of Claim

If a Participant's claim has been denied or if the Participant has not received written notice of denial within the period prescribed by Section 10.5(a), he may file an appeal with the Administrative Committee. The Participant or his duly authorized representative may request to review pertinent documents. The appeal must be submitted in writing within sixty (60) days of the date the Participant receives notice of the denial. The appeal may be made by the Participant or his duly authorized representative. The appeal must state the reasons for the appeal and shall be accompanied by any evidence or documentation to support the Participant's position. The Administrative Committee shall review the Participant's appeal promptly and shall advise the Participant of his decision in writing, in language calculated to be understood by the Participant, stating (i) the specific reasons for his decision with specific reference to pertinent Plan provisions on which the decision is based, (ii) that the Participant is entitled to receive, upon request and free of charge, reasonable access to and copies of all documents, records, and other information relevant to his claim, and (iii) that the Participant has a right to bring an action under Section 502(a) of ERISA.

This written decision shall be sent to the Participant (at his last address appearing on the records of the Plan) by mail no later than 60 days after receipt of the written appeal, unless special circumstances require an extension of time for processing the appeal, obtaining more information or conducting an investigation of facts. In no event shall the written decision be sent to the Participant later than 120 days after receipt by the Administrative Committee of the written appeal. The determination of the Administrative Committee shall be final and binding on all parties and not subject to further appeal.

10.5(c) Exclusive Method

The procedure for review of claims outlined in this Section 10.5 is the exclusive method available for resolving claims under the Plan, notwithstanding the existence of other Employer procedures applicable to Employee grievances in other areas. No Participant or beneficiary is entitled to bring any action, whether at law or in equity, against any Employer or the Trustee or any of their respective agents, officers or employees, including the Plan Administrator, his designees, or the Chief Human Resources Officer in connection with any right, privilege, or benefit provided under this Plan unless and until, as a condition precedent, all of the remedies provided under this Section 10.5 have been exhausted.

10.6 Plan Expenses

The Company may, in its sole discretion, determine from time to time which expenses incident to the operation and maintenance of the Plan, and the fees and expenses of the Trustee will be paid by either the Company or the Plan Participants. Any fees and expenses not paid by the Company shall be paid by Plan Participants.

All brokerage fees and commissions, stock transfer taxes, and other charges incurred by the Trustee in connection with the purchase and sale of shares of Common Stock for the CEG Common Stock Fund shall be borne by the CEG Common Stock Fund. All expenses and other charges incurred by the Other Investment Funds shall be borne by the respective fund.

Administrative fees charged by the institutions which issue contracts for the Default Investment Fund shall be borne by the Default Investment Fund and shall be reflected in the interest rate for such Fund.

Loan initiation fees will be paid by Plan Participants as set forth in Section 9.13.

The Plan Administrator shall not receive any compensation for his services as Plan Administrator.

10.7 Fiduciary Responsibilities

The Plan Administrator is the named fiduciary under the Plan within the meaning of Section 402(a) of ERISA, and shall control and manage the operation and administration of the Plan.

The Plan Administrator (and his delegatees), the Investment Committee, the Administrative Committee, the Trustee, and any other person who is deemed to be a fiduciary under the Plan, shall not be liable for a breach of fiduciary responsibility of another fiduciary under the Plan except to the extent it or he (a) shall have participated knowingly in, or shall have knowingly undertaken to conceal, an act or omission of such fiduciary, knowing such act or omission was a breach of the fiduciary's fiduciary responsibilities, (b) shall have, through a breach of its or his fiduciary responsibilities, enabled such fiduciary to commit a breach of its or his fiduciary responsibilities, or (c) shall have knowledge of a breach of fiduciary responsibilities by such fiduciary, unless it or he has made reasonable efforts to remedy the breach.

This Plan is an ERISA Section 404(c) plan, as described in Section 404(c) of ERISA and defined by Section 2550.404(c)-1 of Title 29 of the Code of Federal Regulations. Under ERISA Section 404(c), Plan Participants and beneficiaries are generally deemed to be responsible for the results of their investment decisions, and fiduciaries of the Plan may be relieved of liability for any loss, or with respect to any breach of part 4 of Title I of ERISA, that is the direct and necessary result of the exercise of control by Plan Participants and beneficiaries over assets in their Plan accounts.

10.8 Indemnification

The Plan Administrator (and his delegatees), members of the Board of Directors, the Executive Group, and the Investment Committee, the Administrative Committee, and any other officer or employee of any Employer shall be indemnified by the Company or from proceeds under insurance policies purchased by the Company against any and all liabilities arising by reason of any act or failure to act made in good faith pursuant to the provisions of the Plan, including expenses reasonably incurred in the defense of any claim relating thereto.

Article XI – Management of Funds

11.1 Trust Fund

The Company shall maintain a Trust Agreement with a Trustee, pursuant to which a Trust shall be established to hold the assets of the Plan. All cash contributions made by Participants and the Company under the Plan shall be paid over to the Trustee as soon as administratively practicable for the purpose of providing benefits under the Plan. No part of the corpus of or income from these funds shall be used for, or diverted to, purposes other than for the exclusive benefit of the Participants and their beneficiaries.

11.2 Trust Agreement; Powers of Trustee

The Trust Agreement shall be subject to the approval of the Board of Directors prior to execution of the Trust Agreement by the Company. The Company or the Plan Administrator may from time to time amend the Trust Agreement and shall give written notice of any such amendment to the Trustee. The Trust Agreement, as amended from time to time, shall contain provisions appropriate to carrying out the purposes of the Plan, including, but not limited to, provisions with respect to (i) the power and authority of the Trustee, (ii) the investment, reinvestment, control, and disbursement of the Trust assets, (iii) the contract or contracts with one or more financial institutions for the Default Investment Fund, and (iv) the authority of the Company or the Plan Administrator to amend the Trust Agreement, review the performance of the Trustee, and to terminate the Trust Agreement and settle the account of the Trustee.

11.3 Removal and Resignation of Trustee

The Company shall have the power, without terminating the Trust Agreement, to remove the Trustee and to designate a successor Trustee upon such removal or in the event the Trustee elects to resign.

11.4 Accounts and Records Maintained by Trustee

The Trustee or the Plan Administrator shall keep complete and accurate records of all of the assets of, and transactions involving, the Investment Funds with respect to Participant Contribution Accounts under the After-Tax and/or Before-Tax Options, the Company Matching Contribution Accounts, the Employee Stock Accounts and Rollover Accounts. If the records are maintained by the Trustee, it shall, in a timely manner, prepare and render all reports and accounting required by law or regulation and shall provide the Plan Administrator with such reports, accountings, and other information as he may reasonably request. All such records shall be available for inspection and copying during the Trustee's normal business hours by the Plan Administrator, who may elect to employ an independent certified public accounting firm to review the accounts and records maintained by the Trustee as of the close of each Plan Year and report the results of such review to the Plan Administrator. This report shall be made available by the Plan Administrator to the Board of Directors, along with such other reports and information as the Board of Directors shall, from time to time, request.

11.5 Voting Rights

11.5(a) Common Stock

Each Participant shall have the right, and shall be afforded the opportunity (on the prescribed form) to instruct the Trustee how to vote or whether or not to tender shares of the Company's Common Stock allocated to his Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account in the CEG Common Stock Fund. To the extent possible, fractional shares will be combined and voted by the Trustee to reflect the instructions of the Participants whose Participant Contribution Accounts, Company Matching Contribution Accounts, Employee Stock Accounts, and Rollover Accounts in the CEG Common Stock Fund have been allocated with such fractional shares. Shares of Common Stock with respect to which no instructions are received shall be tendered by the Trustee, but shall be voted by the Trustee in the same proportions as the Trustee was instructed to vote with respect to the shares for which it received instructions. At the time of the mailing of any notice of an annual or special meeting of the Company's Common Stockholders, a copy of such notice and all accompanying proxy solicitation material, together with the prescribed voting instruction form, shall be furnished to each Participant.

In the case of a tender offer, or other right or option with respect to Common Stock, a Participant who does not issue valid directions to the Trustee to sell, offer to sell, exchange or otherwise dispose of such Participant's Common Stock, shall be deemed to have directed the Trustee that shares of Common Stock allocated to his Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account remain invested in the CEG Common Stock Fund. A Participant's instruction to tender shares of Common Stock invested in the CEG Common Stock Fund shall not constitute an Appropriate Request for a withdrawal or distribution pursuant to Articles VII and VIII, respectively. Any proceeds received as a result of the sale of Common Stock pursuant to a tender offer shall be credited to the Participant's accounts from which the tendered shares were taken and shall be reinvested in the CEG Common Stock Fund provided Common Stock is available for purchase and continues to be traded on a national securities exchange. In the event that, subsequent to any tender offer, Common Stock is no longer available and traded on a national securities exchange, Participants may elect to invest the proceeds received from the tendered Common Stock in one or more of the other available Investment Funds other than the CEG Common Stock Fund, by submitting an Appropriate Request to the Plan Administrator. Until such time that the Appropriate Request is received by the Plan Administrator, the proceeds received from the tendered Common Stock shall be invested in the Default Investment Fund.

11.5(b) Other Investment Funds

Each Participant shall have the right, and shall be afforded the opportunity (on the prescribed form), to instruct the Trustee how to vote (if applicable) the Other Investment Fund shares held in his Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account. Shares of Other Investment Funds with respect to which no instructions are received shall be voted (if applicable) by the Company. At the time of the mailing of any notice of an annual or special meeting of any Other Investment Fund, a copy of such notice and all accompanying proxy solicitation material, together with the prescribed voting instruction form, shall be furnished by the Trustee to each Participant holding shares in the Other Investment Fund.

Article XII – Amendment, Termination, Mergers, or Consolidations

12.1 Amendment

The Plan may be amended, from time to time, by the Plan Administrator as shall be necessary or advisable in the interpretation, administration, or operation thereof or as required by law upon the advice of counsel. Further, the bonuses and incentives includable in Eligible Compensation in Appendix C may be amended by the Chief Executive Officer of the Company and the Chief Human Resources Officer of the Company, acting together. The Executive Group may make any amendment to the Plan that does not increase annual Plan liabilities by more than $1 million per amendment; the Company's Chief Executive Officer shall report all such amendments to the Board of Directors no less frequently than annually. The Chief Human Resources Officer may make any amendment to the Plan that does not increase the annual Plan liabilities materially, or as required by law upon the advice of counsel. In all other cases, the Plan may only be amended by resolution of the Board of Directors, who shall be entitled to delegate such authority. Under no circumstances shall the Plan be amended to cause any of the assets of the Investment Funds to be used for or be diverted to any purpose other than the exclusive benefit of Participants or their beneficiaries and defraying reasonable expenses of administering the Plan, or to cause the elimination or reduction of any Plan benefit as prohibited under the provisions of Code Section 411(d)(6). Furthermore, no amendment may retroactively reduce the rate at which a Participant shall make contributions to such Investment Funds, or, except as may be required to conform with future governmental regulations, adversely affect the rights of any Participant with respect to contributions made on his behalf prior to the date of such amendment.

12.2 Termination

The Plan may be terminated, in whole or in part, at any time, by resolution of the Board of Directors. The Trustee will thereafter be directed to liquidate the Investment Funds. Upon any termination of the Plan other than as provided in Section 13.9, all Participant Contribution Accounts, Company Matching Contribution Accounts, Employee Stock Accounts, Rollover Accounts, and dividends, if any, accumulated under the provisions of Section 8.5(b), shall be deemed to be matured, and distribution of the balances in such accounts shall be promptly made by the Trustee in accordance with direction from the Plan Administrator. In making such distribution, any and all determinations, divisions, appraisals, apportionments, and allotments so made shall be final and conclusive.

12.3 Merger or Consolidation

In the event of any merger or consolidation of the Plan with, or transfer of any assets or liabilities of the Plan to, any other plan, each Participant shall be entitled to receive a benefit immediately after such merger, consolidation, or transfer (computed as if such other plan had then terminated) which is equal to or greater than the benefit he would have been entitled to receive immediately before such merger, consolidation, or transfer (computed as if the Plan had then terminated).

Article XIII – General Provisions

13.1 Source of Payment

Benefits under the Plan shall be payable only out of the Investment Funds. The Company shall have no responsibility or liability (legal or otherwise) to make any payment of benefits under the Plan. No persons shall have any rights under the Plan with respect to such Investment Funds, or against the Plan Administrator (and his delegatees), the Company, any other Employer, the Board of Directors, the Executive Group, the Investment Committee, the Administrative Committee, or the Trustee, except as specifically provided for under the Plan.

13.2 Inalienability of Benefits

13.2(a) General

No benefit or interest available under the Plan will be subject to assignment, attachment, alienation, or other legal process, either voluntarily or involuntarily. Except as provided in Section 13.2(b), the preceding sentence will also apply to the creation, assignment, or recognition of a right to any benefit payable with respect to a Participant pursuant to a domestic relations order. Except as provided in Section 13.2(c), benefits under the Plan will be made available to and in the name of the person entitled to such benefits under the terms of the Plan, or to and in the name of such person's authorized representative. Payments to any financial institution to the credit of such person will constitute payments to and in the name of the person entitled to such payments under the terms of the Plan.

In addition, to the extent permitted by Code Section 401(a)(13), a Participant's benefits may be offset against an amount that the Participant is ordered or required to pay to this Plan pursuant to a judgment in a criminal action involving this Plan, a civil judgment in connection with a violation or alleged violation of Part 4 of Subtitle B of Title I of ERISA, or a settlement agreement between the Secretary of Labor and the Participant in connection with a violation or alleged violation of such Part. Furthermore, this Section 13.2(a) shall not preclude either (i) the enforcement of a Federal tax levy made pursuant to Code Section 6331, or (ii) the collection by the United Sates on a judgment resulting from an unpaid tax assessment, to the extent permitted under Code Section 401(a)(13) and the regulations thereunder.

13.2(b) Qualified Domestic Relations Orders

The anti-alienation provisions of Section 13.2(a) do not apply to qualified domestic relations orders, as the term is defined in Code Section 414(p), ERISA 206(d)(3) and any applicable regulations thereunder. The Plan Administrator has established and will maintain written procedures to determine the qualified status of domestic relations orders and to administer distributions under such qualified orders. Further, to the extent provided under a qualified domestic relations order, a former Spouse of a Participant shall be treated as the Spouse or surviving Spouse for all purposes under the Plan.

13.2(c) Miscellaneous Exceptions

The anti-alienation provisions of Section 13.2(a) do not apply to the payment of taxes to any governmental agency, to the extent such payment is authorized by the person entitled to such payment under the terms of the Plan, or is otherwise required by a law that is not preempted by the ERISA anti-alienation provisions.

13.3 Section 16 of the Securities Exchange Act of 1934

Each Participant who is subject to Section 16 of the Securities Exchange Act of 1934 and the rules and regulations promulgated thereunder shall, in effecting any transaction in the Plan, comply with all applicable provisions of such law, rules, and regulations in addition to the applicable Plan provisions.

13.4 Put Option Rights Applicable to Common Stock

Effective February 1, 2006, but only to the extent required under the applicable rules of Code section 4975(e)(7) with regard to an employee stock ownership plan of the type represented by the CEG Common Stock Fund, shares of Company Stock distributed to a Participant or Beneficiary with respect to the CEG Common Stock Fund (including a distribution that is a withdrawal) that at the time of the distribution, are not readily tradable on an established market within the meaning of Code section 409(h), as determined by the Plan Administrator, shall be subject to a put option which shall permit the Participant or Beneficiary to sell such stock to the Company at any time during two option periods, at the fair market value of such shares (as of the most recent valuation date). The first period shall be for at least 60 days beginning on the date of distribution. The second period shall be for at least 60 days beginning on the first valuation date in the calendar year following the year in which the distribution was made. The Plan Administrator may direct the Trustee to purchase shares tendered to the Company under a put option. Notwithstanding the foregoing, the period during which the put option is exercisable shall not include any time when the shares are determined by the Plan Administrator to be readily tradable, or when a Participant or Beneficiary is unable to exercise the put option because the Company is prohibited from honoring it, as determined by the Company's chief legal officer, by applicable federal or state laws, including for these purposes any insider trading policy adopted by the Company in furtherance of applicable federal or state laws. Payment for any shares of stock sold under a put option shall be made in a lump sum or in substantially equal annual installments over a period not exceeding five years, with interest payable at a reasonable rate (as determined by the Plan Administrator). For purposes of this Section, shares of Company Stock that are listed on a national securities exchange registered under Section 6 of the Securities Exchange Act of 1934 or that are quoted on a system sponsored by a national securities association registered under section 15A(b) of the Securities Exchange Act of 1934 shall not be treated as ceasing to be readily tradable for these purposes merely because the Participant or Beneficiary who receives a distribution of such shares (i) is subject to a stock ownership policy of the Company, (ii) would be subject to liability under Section 16(b) of the Securities Exchange Act of 1934 if the Participant or Beneficiary transferred such shares, or (iii) is subject to volume limitation or manner of sale requirements pursuant to Rule 144 under the Securities Act of 1933 with respect to transfers of such shares. Except as may be permitted under applicable law or regulations, the rights of a Distributee of Company Stock under this Section 13.4 shall survive the termination of the Plan and any amendment of the Plan. The Plan is not obligated to acquire securities from a Participant or Beneficiary at an indefinite time that is determined upon the happening of an event, such as the death of the Participant or Beneficiary.

13.5 Loss or Decline in Value

Neither the Plan Administrator, the Company, the Board of Directors, the Executive Group, the Investment Committee, the Administrative Committee, any officer or employee of any Employer, the Trustee, nor their delegatees, guarantees the assets of the Trust in any manner against loss or decline in value.

13.6 No Right to Employment

Nothing contained in this Plan shall be construed as a contract of employment between any Participating Employer and any Employee, or as a right of any Employee to continue in the employment of any Participating Employer or as a limitation of the right of any Participating Employer to discharge any Employee with or without cause.

13.7 Controlling Law

The Plan and its administration shall be governed by the laws of the State of Maryland, except to the extent preempted by Federal law.

13.8 Gender and Number

The masculine pronoun, when used herein, refers to both men and women, and words used in the singular are intended to include the plural, whenever appropriate.

13.9 Titles and Headings

Titles of Articles and headings to Sections in the Plan are placed herein solely for convenience of reference and, in any case of conflict, the text of the Plan, rather than such titles and headings, shall control.

13.10 Approvals and Effective Date

This Plan as amended and restated shall become effective, provisionally, on September 1, 2006, and shall be submitted to the Internal Revenue Service for its review and approval. The Company may make further amendments to this Plan which it deems necessary or advisable to achieve Internal Revenue Service approval. Upon such approval, the effectiveness of this Plan as amended and restated shall become final. If such approval is not forthcoming in a form satisfactory to the Company, this Plan as amended and restated shall be treated as null and void ab initio; and the Plan as previously approved by the Internal Revenue Service shall be deemed to have continued in operation in all respects and without change from that day forward.

****

IN WITNESS WHEREOF, this restatement and the appendices attached thereto, effective January 31, 2012, were duly executed on this ______ day of January, 2012.

____
Mary Lauria
Chief Human Resources Officer

APPENDIX A

DEFINITIONS

As used in the Plan, the following terms shall have the meaning set forth below, unless a different meaning is clearly required by the context in which the term is used.

1 "Administrative Committee" means the Adminstrative Committee consisting of members appointed from time to time by the Chief Executive Officer of the Company, or his delegate.

2 "After-Tax Option" (formerly known as the "Thrift Option") means the portion of the Plan under which an eligible Employee may contribute after-tax amounts to the Plan through payroll deduction.

3 "Appropriate Request" is a request by a Participant, in the written, electronic, telephonic, or other form and manner provided by the Plan Administrator that is appropriate for the intended purpose. To constitute an Appropriate Request, such request must be completed correctly and, if required to be in writing, duly executed and delivered to the Plan Administrator or his designated representative.

4 "Basic Contribution" means a Participant's contribution to the Plan through the After-Tax and/or Before-Tax Options in an amount up to six percent (6%) of the Participant's Eligible Compensation.

5 "Board of Directors" means the Board of Directors of the Company.

6 "Before-Tax Option" (formerly known as the "Deferred Compensation Option") means the portion of the Plan under which an eligible Employee may contribute pre-tax amounts to the Plan through payroll deduction.

7 "CEG Common Stock Fund" means the Investment Fund under the Plan composed of shares of Common Stock and any amounts allocated to the CEG Common Stock Fund but not yet invested in Common Stock. The CEG Common Stock Fund also includes the earnings on amounts not yet invested in Common Stock. The shares of Common Stock held by the CEG Common Stock Fund are purchased by the Trustee either in the open market or otherwise acquired.

8 “Closing Price” means the price as of the close of the New York Stock Exchange as determined by the Trustee based upon valuations provided by Investment Managers (as that term is defined in the Trust Agreement), trustee of group trusts, sponsors of Mutual Funds, records of securities exchanges or valuation services, market data providers or qualified appraisers.

9 “Code” means the Internal Revenue Code of 1986, as amended or replaced from time to time.

10 “Common Stock” means the Common Stock of the Company.

11 “Company” means Constellation Energy Group, Inc. and its successors and assigns.

12 “Company Matching Contribution Account” means an account established for each Participant into which Company Matching Contributions are made. A Company Matching Contribution Account is established for each Participant in the Default Investment Fund, the CEG Common Stock Fund and the Other Investment Funds pursuant to the Participant’s investment designations. Prior to January 1, 2012, it meant an account established for each Participant in the CEG Common Stock Fund, into which shares of Common Stock purchased or acquired by the Trustee with Company Matching Contributions, loan repayments, or dividends on shares of Common Stock already in such account are invested, or an account established for each Participant in the Default Investment Fund and the Other Investment Funds pursuant to the interfund transfer provisions as set forth in the Plan.

13 <u>“Company Matching Contributions”</u> means contributions made by the Company to the Plan in an amount equal to one-half (1/2) of each Participant’s Basic Contribution ($.50 for each $1.00).

14 <u>“Compensation”</u> as used throughout this Plan is intended to have the same meaning as under Code Section 414(s), and is limited to amounts earned while an Employee.

In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provision of the Plan to the contrary, annual Compensation of each Employee taken into account for any Plan Year beginning after December 31, 2001 under the Plan shall not exceed $200,000, as adjusted for cost-of-living increases in accordance with Code Section 401(a)(17)(B). The cost-of-living adjustment in effect for a calendar year applies to annual compensation for such Plan Year.

Compensation shall also include any elective deferrals, within the meaning of Code Section 402(g)(3), of the Employer with respect to the Employee, and any amount which is contributed or deferred by the Employer at the election of the Employee and which is not includable in the gross income of the Employee by reasons of Code Sections 125 or 132(f)(4). A differential wage payment (as defined in Code Section 3401(h)(2)) shall not be included in the definition of Compensation.

15 <u>“Corporate Performance Award Program”</u> means the program established by the Company through which the Company made an annual contribution to the Employee Stock Account of each eligible Employee based on the attainment of certain annual performance goals established by the management of the Company. Corporate Performance Award Program contributions and earnings thereon are taxed to the Employee when distributed or withdrawn from the Plan. The Company ceased making Corporate Performance Award Program contributions to the Plan after 1992.

16 <u>“Default Investment Fund”</u> means the T. Rowe Price Retirement Fund dated nearest to the year of the Participant’s 65th birthday, or such other fund as may be designated by the Investment Committee.

17 <u>“Designating Authority”</u> means the Board of Directors or the Executive Group; provided, however, that (i) the Executive Group shall be a Designating Authority only if the designation of a Participating Employer does not increase annual Plan liabilities by more than $1 million, and (ii) the Company’s Chief Executive Officer shall report all designations of Participating Employers by the Executive Group to the Board of Directors no less frequently than annually.

18 <u>“Direct Rollover”</u> means a payment by the Plan to the Eligible Retirement Plan specified by the Distributee.

19 <u>“Distributee”</u> means an Employee or former Employee. In addition, the Employee’s or former Employee’s surviving Spouse (or a non-spouse beneficiary as described in Section 402(c)(11) of the Code) and the Employee’s or former Employee’s Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Section 414(p) of the Code, are Distributees with regard to the interest of the Spouse or former Spouse.

20 “<u>Effective Date</u>” means October 1, 2004.

21 <u>“Eligible Compensation”</u> means the base rate of pay paid by the Employer to an Employee for the Plan Year, before any reductions, but excluding overtime, and certain bonuses, incentives, or other forms of extra compensation. The bonuses and incentives to be included in Eligible Compensation are those forms of compensation enumerated in Appendix C attached hereto.

In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provision of the Plan to the contrary, annual Compensation of each Employee taken into account for any Plan Year beginning after December 31, 2001 under the Plan shall not exceed $200,000, as adjusted for cost-of-living increases in accordance with Code Section 401(a)(17)(B). The cost of living adjustment in effect for a calendar year applies to annual compensation for such Plan Year.

22 “Eligible Retirement Plan” means an individual retirement account described in Section 408(a) of the Code, a Roth individual retirement account described in 408A(b) of the Code (subject to current Roth individual retirement account conversion rules), an individual retirement annuity described in Section 408(b) of the Code, an annuity plan described in Section 403(a) of the Code, an annuity contract described in Section 403(b) of the Code, an eligible plan under Section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state and which agrees to separately account for amounts transferred into such plan from this Plan, or a qualified trust described in Section 401(a) of the Code, that accepts the Distributee’s Eligible Rollover Distribution. The definition of Eligible Retirement Plan shall also apply in the case of a distribution to a surviving Spouse, or to a Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Section 414(p) of the Code.

23 “Eligible Rollover Distribution” means any distribution from an Eligible Retirement Plan of all or any portion of the balance to the credit of a Distributee, except that an Eligible Rollover Distribution does not include: any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for the life (or life expectancy) of the Distributee or the joint lives (or joint life expectancies) of the Distributee and the Distributee’s designated beneficiary, or for a specified period of ten years or more; any distribution to the extent such distribution is required under Section 401(a)(9) of the Code; any amount that is distributed on account of hardship; and the portion of any distribution that is not includible in gross income unless specifically allowed under Section 3.3 (determined without regard to the exclusion for net unrealized appreciation with respect to employer securities).

24 “Employee” means any person who is employed by the Employer maintaining the Plan or any other Employer required to be aggregated with such Employer under Code Sections 414(b), (c), (m), or (o), but excludes any person who is paid and classified by the Employer as an independent contractor (regardless of whether such person is classified prospectively or retroactively by any court, governmental agency, or other authority as an employee under any federal, state, or local law, regulation, or rule for any income tax, wage withholding, wage and hour, or other purposes). Employee shall include a leased employee within the meaning of Code Sections 414(n)(2). Notwithstanding the foregoing, if leased employees are covered by a plan described in Code Section 414(n)(5) and such leased employees do not constitute more than 20% of the Employer’s Nonhighly Compensated Employee work force, the term “leased employee” shall not include such leased employees.

An Employee may be a Full-Time Employee or an On-Call Employee. A Full-Time Employee is any Employee employed on an ongoing and regular basis who has a basic workweek generally consisting of 40 hours, although Employees who work part-time on a regular and ongoing basis with a basic workweek of less than 40 hours are also considered to be Full-Time Employees. On-Call Employees constitute a reasonable classification of Employees who do not have a basic workweek, but rather work on an irregular, “on call” basis and do not participate in any “time off” or related benefit plans and are compensated only for those hours actually worked.

25 “Employee Stock Account” means an account established for each Participant in the CEG Common Stock Fund, into which shares of Common Stock purchased or acquired by the Trustee with Corporate Performance Award Program contributions, loan repayments, or with dividends on shares of Common Stock already in

such account are invested. The Employee Stock Account in the CEG Common Stock Fund is also comprised of amounts for an Employee or former Employee who elected to direct the transfer of the entire balance of his account in the Baltimore Gas and Electric Company Employee Stock Ownership Plan (ESOP) to this Plan upon termination of the ESOP. An Employee Stock Account is also established for each Participant in the Default Investment Fund and the Other Investment Funds pursuant to the interfund transfer provisions as set forth in the Plan.

26 "Employer" means the Company and any successor which shall maintain this Plan, and any subsidiaries or other affiliates required to be aggregated with the Company under Code Sections 414(b), (c), (m), or (o).

27 "ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and the pertinent rules and regulations promulgated thereunder.

28 "Executive Group" means the Company's Chief Executive Officer, Chief Financial Officer, General Counsel, and Chief Human Resources Officer (or the positions succeeding to those functions), acting collectively.

29 "Full-Time Employee" – See definition of "Employee."

30 "Highly Compensated Employee", for purposes of the operation of the Plan, generally means an Employee who either received compensation greater than the amount prescribed in Code Section 414(q)(1) in the year preceding the current Plan Year (e.g., $90,000 for 2003 to determine who is a Highly Compensated Employee in 2004). As used in this definition, compensation means compensation under Code Section 414(q)(4) and the accompanying regulations.

As used below in describing a Highly Compensated Employee, the “determination year” is the Plan Year for which testing is performed, and the “look-back year” is the immediately preceding 12-month period. Highly Compensated Employees may include both active and former Highly Compensated Employees.

As provided under Code Section 414(q), an active Highly Compensated Employee includes any Employee who performed services for the Employer during the determination year and who is described in either paragraphs (a) or (b) below.

(a) Employees who at any time during the determination year or look-back year were 5-percent owners of the Employer, within the meaning of Code Section 414(q)(2).

(b) Employees who received compensation during the look-back year from the Employer in excess of $80,000 (as adjusted under Code Section 414(q)(1)).

A former Highly Compensated Employee includes any former Employee who separated from service (or was deemed to have separated) prior to the determination year, performs no service for the Employer during the determination year, and was an active Highly Compensated Employee for either the separation year or any determination year ending on or after the day the Employee reaches age fifty-five (55).

Unless otherwise specified, the term Highly Compensated Employee as used throughout the Plan shall refer to an active Highly Compensated Employee.

The determination of who is a Highly Compensated Employee will be made in accordance with Code Section 414(q) and the regulations thereunder.

31 “Hour(s) of Service” means: (1) each hour for which an Employee is directly or indirectly compensated or is entitled to receive Compensation from the Employer for the performance of duties during the applicable computation period; (2) each hour for which an Employee is directly or indirectly compensated or entitled to receive Compensation from the Employer (irrespective of whether the employment

relationship has terminated) for reasons other than performance of duties (such as vacation, holidays, sickness, jury duty, disability, lay-off, military duty, or leave of absence) during the applicable computation period; (3) each hour otherwise recognized under one or more of the medical or time-off fringe benefit plans maintained by the Employer; and (4) each hour for which back pay is awarded or agreed to by the Employer without regard to mitigation of damages. The same Hour of Service shall not be credited under (1), (2), or (3), as the case may be, and under (4).

Notwithstanding (2) above, no more than 501 Hours of Service are required to be credited to an Employee on account of any single continuous period during which the Employee performs no duties (whether or not such period occurs in a single computation period). An hour for which an Employee is directly or indirectly paid, or is entitled to payment on account of a period during which no duties are performed is not required to be credited to the Employee if such payment is made or due under a plan maintained solely for the purpose of complying with applicable worker's compensation, or unemployment compensation or disability insurance laws. An Hour of Service is not required to be credited for a payment which solely reimburses an Employee for medical or medically related expenses incurred by the Employee.

For purposes of (2) above, a payment shall be deemed to be made by or due from the Employer regardless of whether such payment is made by or due from the Employer directly, or indirectly through, among others, a trust fund, or insurer, to which the Employer contributes or pays premiums and regardless of whether contributions made or due to the trust fund, insurer, or other entity are for the benefit of particular Employees or are on behalf of a group of Employees.

An Hour of Service must be counted for the purpose of determining employment commencement date (or reemployment commencement date). The provisions of Department of Labor Regulations 2530.200b-2(b) and (c) are incorporated herein by reference.

32 Reserved.

33 “Investment Committee” means the Investment Committee consisting of members of senior management of the Company appointed from time to time by the Chief Executive Officer of the Company. The Investment Committee shall have the authority to delegate its duties and responsibilities hereunder in writing.

34 “Investment Fund(s)” means, dependent upon the context in which used, one or more of the following funds:

(1) CEG Common Stock Fund,

(2) Default Investment Fund, or

(3) any Other Investment Fund.

35 “Military Leave of Absence” means a leave of absence from an Employer for a period of “qualified military service” as defined under Code Section 414(u)(5).

36 “Mutual Fund” means any mutual fund selected by the Investment Committee as an Investment Fund (other than the CEG Common Stock Fund and the Default Investment Fund).

37 “Nonhighly Compensated Employee” means any Employee who is not a Highly Compensated Employee.

38 “On-Call Employee” – See definition of “Employee.”

39 “Other Investment Fund” means any Mutual Fund, common, collective, or master trust fund, or other pooled investment fund selected by the Investment Committee as an Investment Fund (other than the CEG Common Stock Fund and Default Investment Fund).

40 “Participant” means, except as provided in Articles VII, VIII, and IX, any eligible Employee who has completed the length-of-service requirements and become a member of the Plan under the provisions of Article II.

41 “Participant Contribution Account” means an account(s) established to receive contributions made by a Participant, or made by the Company on the Participant’s behalf, under the After-Tax and/or Before-Tax Options, and to which loan repayments and earnings on amounts held in the respective accounts are allocated. A Participant Contribution Account is established in one or more of the Investment Funds at the election of the Participant. Where the Participant Contribution Account is established in the CEG Common Stock Fund, shares of Common Stock are allocated to the account. The Common Stock allocated to the account is purchased by the Trustee with cash contributions and with dividends received on shares of Common Stock already in such account. Where a Participant Contribution Account is established in one of the other Investment Funds, cash contributions and earnings on amounts already in the Participant Contribution Account, are allocated to the Account. A Participant Contribution Account is also comprised of allocations of any cash contributed during a Payroll Period by the Participant, or by the Company on the Participant’s behalf, but not yet transferred to the Trustee.

42 “Participant Contributions” means a Participant’s Basic Contributions and Supplemental Contributions, as applicable.

43 “Participating Employer” means any Employer that has been designated as a Participating Employer by the Designating Authority, as set forth in Appendix E.

44 “Party in Interest” is an active Employee and any other person described as a party in interest under ERISA Section 3(14).

45 “Payroll Period” means the basic work period of an Employee, which (i) for Employees paid on a weekly basis consists of seven (7) twenty-four (24) hour days, Monday through Sunday, (ii) for Employees paid on a bi-weekly basis consists of fourteen (14) twenty-four (24) hour days, Monday through the second following Sunday, and (iii) for Employees paid on a monthly basis consists of the days of each calendar month.

46 “Plan” means the Constellation Energy Group, Inc. Employee Savings Plan.

47 “Plan Administrator” means the Director – Corporate Benefits of the Company (or the position succeeding to that function) appointed by the Board of Directors.

48 “Plan Year” means the Plan’s accounting year of twelve (12) months beginning on January 1 of each year and ending the following December 31.

49 “Qualified Nonelective Contributions” means the contributions, if any, made by the Company to the Plan in the Company’s sole discretion, provided that such contributions are:

(i) allocated uniformly on the basis of Compensation to the Participant Contribution Account of each Participant who is a Nonhighly Compensated Employee and is eligible to participate in the Before-Tax Option under the Plan; and

(ii) for all purposes under the Plan, except as provided in Section 7.6 with respect to hardship withdrawals, treated as amounts contributed under the Before-Tax Option.

50 “Rollover Account” means an account(s) established when a Participant transfers, in cash, all or a portion of an Eligible Rollover Distribution to the Plan in accordance with the rollover provisions of the Plan as set forth in Article III. A Rollover Account is established in one or more of the Investment Funds at the election of the Participant. Where the Rollover Account is established in the CEG Common Stock

Fund, shares of Common Stock are allocated to the Account. Such shares are purchased by the Trustee with the transferred cash and with dividends received on shares of Common Stock already in such Account. Where a Rollover Account is established in one of the other Investment Funds, transferred cash and earnings on amounts already in the Rollover Account, are allocated to the Account.

51 "Spouse" means a person of the opposite sex recognized as a Participant's spouse under Federal law on the determination date.

52 "Supplemental Contribution" means a Participant's contribution to the Plan through the After-Tax and/or Before-Tax Options in excess of the Participant's Basic Contributions.

53 "Total Account Balance" means, for purposes of determining the maximum loan available under the Plan, the total dollar value of the Participant's Plan accounts (except dividends, if any, accumulated under the provisions of Section 8.5) as of the date the Plan receives the Participant's executed loan agreement.

54 "Transaction Price" means the actual price, net of commissions, the Trustee receives or pays for Common Stock when the Trustee sells or buys Common Stock on the open market in order to satisfy Plan provisions relating to contributions, interfund transfers, withdrawals, distributions and loans.

55 "Treasury" means the federal Treasury Department.

56 "Trust" means the trust established under the provisions of Article XI of the Plan.

57 "Trust Agreement" means the agreement between the Company and the Trustee, under which the assets of the Plan are held and managed pursuant to Article XI of the Plan.

58 "Trustee" means T. Rowe Price Trust Company or any successor Trustee appointed by the Board of Directors.

APPENDIX B

CODE LIMITATIONS ON CONTRIBUTIONS TO THE PLAN

B-1 Dollar Limitation on Participants' Before-Tax Option Contributions – During any Plan Year, a Participant's contributions under the Before-Tax Option of the Plan, when combined with his elective deferrals within the meaning of Code Section 402(g)(3) under all other plans of the Employer and any other employer during the Plan Year, may not exceed the limitation of Code Section 402(g) (e.g., $13,000 in 2004). This dollar limitation will be adjusted annually at the same time and in the same manner as provided under Code Section 402(g)(5). To prevent the limitation from being exceeded in any Plan Year, the Plan Administrator may prospectively limit the rate of contribution which a Participant may elect to contribute under the Before-Tax Option. Participants whose Before-Tax Option contributions are limited by this Section B-1 are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation.

If due to an administrative error a Participant's contributions under the Before-Tax Option exceed the limitation of Code Section 402(g) as of the close of any Plan Year, the Participant will receive a distribution from the Plan of the amount constituting such excess Before-Tax Option contributions and any income or loss allocable thereto by no later than April 15th following the close of the Plan Year to which such excess deferrals relate.

If during the Plan Year in which such excess Before-Tax Option contributions occurred, or prior to March 1st following the close of such Plan Year, a Participant submits a written certification to the Plan Administrator stating that all or a portion of the Participant's contributions to the Plan under the Before-Tax Option constitute excess deferrals within the meaning of Code Section 402(g), the Participant will receive a distribution of such excess deferrals, which will be designated as such by the Company, and any income or loss allocable to such excess deferrals by no later than April 15th following the close of the Plan Year to which the excess deferrals relate.

To the extent any Company Matching Contributions were allocable to the Participant's account as a result of excess deferrals, such Company Matching Contributions and any income or loss allocable thereto will be forfeited and thereafter applied to reduce future Company contributions to the Plan.

Distributions of excess deferrals required under this Section B-1 shall be made first from Participant's Supplemental Contributions made under the Before-Tax Option and income or loss allocable thereto and, thereafter, from Participant's Basic Contributions made under the Before-Tax Option, and income or loss allocable thereto.

Income or loss allocable to excess deferrals for the Plan Year will be computed using either a reasonable method that meets the requirements of Treasury Regulation Section 1.402(g)-1(e)(5)(ii) or the fractional method under Treasury Regulation Section 1.402(g)-1(e)(5)(iii). For the purposes of clarity, the income or loss allocable to excess deferrals will not be calculated for the period after the close of the Plan Year in which the excess deferral occurred and prior to the distribution (i.e. the 'gap period').

For purposes of computing the Section B-2 limitations under Code Section 415(c), excess deferrals under Code Section 402(g) will be treated as contributions under the Before-Tax Option, unless a distribution of such excess deferrals and any income or loss allocable thereto is made no later than April 15th following the close of the Plan Year to which such excess deferrals relate. Excess deferrals under Code Section 402(g) will be treated as contributions under the Before-Tax Option for purposes of computing the Code Section 401(k) limitations as provided in Section B-4.1, but only for contributions on behalf of Highly Compensated Employees, even if such excess deferrals and any income or loss allocable thereto is distributed by April 15th following the close of the Plan Year to which such excess deferrals relate. Excess deferrals by Nonhighly Compensated Employees will not be taken into account.

It is the intent of the Plan that the limitations set forth above will conform to the limitations prescribed by Code Section 402(g). As of the date of any adjustment in the limitations prescribed by Code Section 402(g), the provisions of this Section B-1 will be deemed to have been amended to reflect such adjustment.

B-2 Limitation on Total Annual Additions

B-2.1 Maximum Annual Additions – The total annual additions to a Participant's account under this Plan and any and all other defined contribution plans of the Employer shall not in any limitation year exceed the lesser of the limitation in effect under Code Section 415(c)(1)(A) ($49,000 for 2009) as adjusted for cost of living increases pursuant to Code Section 415(d) or 100% of the Compensation as defined in Section 4.2(b) of the Plan actually paid or made available to the Participant during such limitation year. "Annual addition", for purposes of this Appendix B-2, means the sum of the following amounts allocated to the Participant's Plan accounts for the limitation year:

(a) Employer contributions,

(b) Employee contributions, and

(c) Forfeitures.

Amounts contributed by the Participant under the rollover provisions of the Plan are not considered to be annual additions to a Participant's account for purposes of determining the limitations under this Section. Catch-up contributions under Section 3.1(a) of the Plan and repayment of loans to Participants under Article IX of the Plan are not annual additions to a Participant's account for purposes of determining the limitations under this Section.

B-2.2 Elimination of Excess Annual Additions — To the extent necessary to prevent the limitation of this Section B-2 from being exceeded in any limitation year, the Plan Administrator may prospectively reduce contributions under the Plan during such limitation year. A Participant's prospective Supplemental Contributions under the After-Tax Option will be reduced first, followed in order by Supplemental Contributions under the Before-Tax Option, Basic Contributions under the After-Tax Option, and Basic Contributions under the Before-Tax Option until such reductions eliminate any excess annual additions.

B-2.3 Limitation Year — For purposes of applying the limitations of Code Section 415 to the Plan, the "limitation year" shall be the calendar year.

If the Employer maintains multiple defined contribution plans that are aggregated with the Plan for purposes of Code Section 415 pursuant to Appendix B-2.4 and that have different limitation years, the rules of Code Section 415(c) will be applied to the limitation year of the Plan, and are to be applied with respect to each limitation year of each other such plan. For each limitation year of the Plan, the requirements of Code Section 415 are applied to annual additions that are made for that time period with respect to the Participant under all such aggregated plans.

B-2.4 Aggregated Plans — The sum of the annual additions credited to a Participant's account in any limitation year for all of the qualified defined contribution plans of the Employer or a predecessor employer (as such term in used in Code Section 415(f) and the regulations thereunder), regardless of whether a plan is terminated, may not exceed the limitations of Code Section 415(c).

B-2.5 Incorporation by Reference — Notwithstanding anything contained in this Appendix B or Article IV of the Plan to the contrary, the limitations, adjustments, and other requirements prescribed in this Appendix B-2 shall at all times comply with the provisions of Code Section 415 and the regulations thereunder, the terms of which are specifically incorporated herein by reference. As of the date of any adjustment in the limitations prescribed by Code Section 415(c), the provisions of this Appendix B-2 will be deemed to have been amended to reflect such adjustment.

B-3 Reserved.

B-4 Limitation on Participant Contributions Under the Before-Tax Option (ADP Test)

B-4.1 Maximum Annual Contributions — For each Plan Year, annual Participant contributions under the Before-Tax Option shall satisfy one of the following actual deferral percentage (ADP) tests:

(1) The actual deferral percentage for the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year shall not be more than 125 percent of the actual deferral percentage for the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year, or

(2) The excess of the actual deferral percentage for the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year over the actual deferral percentage for the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year shall not be more than two (2) percentage points. Additionally, the actual deferral percentage for the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year shall not exceed the actual deferral percentage for the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year, multiplied by two (2).

In determining whether the Plan satisfies the limitation under this Section B-4, all Before-Tax Option contributions and other elective deferrals, that are made to the Plan and any other plans of the Employer that are aggregated with the Plan for purposes of Code Section 401(a)(4) and 410(b) (other than Code Section 410(b)(2)(A)(ii)), are to be treated as made under a single plan. If the Plan and any other plans of the Employer are permissively aggregated for purposes of satisfying this limitation under Section B-4, the aggregated plans must also satisfy Code Sections 401(a)(4) and 410(b) as though they were a single plan.

For the purposes of this Section "actual deferral percentage" means, with respect to the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option and the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year, the average of the actual deferral ratios, calculated separately for each Employee who is eligible to participate under the Before-Tax Option for the Plan Year in each group.

The "actual deferral ratio" for each such Employee is equal to the annual Participant contributions under the Before-Tax Option and any "Qualified Nonelective Contribution" made on behalf of such Participant divided by the Participant's Compensation. For purposes of this Section, Compensation generally means an Employee's total Compensation for the Plan Year; however, Compensation does not include amounts related to any portion of the Plan Year in which an Employee was not eligible to participate in the Before-Tax Option of the Plan. The actual deferral ratio of a Highly Compensated Employee is determined by treating all plans of the Employer that are subject to Code Section 401(k) under which the Highly Compensated Employee is eligible to participate (other than those that may not be permissively aggregated) as a single plan.

The actual deferral ratio for each Employee who is eligible to participate under the Before-Tax Option and the actual deferral percentage for the Highly Compensated Employee group and the Nonhighly Compensated Employee group shall be calculated to the nearest one-hundredth of one percent.

B-4.2 Elimination of Excess Contributions – To prevent the limitation under this Section B-4 from being exceeded in any Plan Year, the Plan Administrator may prospectively limit the rate of contribution which a Highly Compensated Employee may elect to contribute under the Before-Tax Option.

The Plan Administrator will establish a maximum rate of contribution for Highly Compensated Employees to avoid exceeding the limits of this Section B-4.

The maximum rate of contribution for Highly Compensated Employees will be determined by first reducing by 1/10 of a percent the rate of contribution under the Before-Tax Option of the Highly Compensated Employees having the highest actual deferral ratio. The rate of contribution will be reduced until the ADP test is satisfied, or until the actual deferral ratio is reduced to the point where it equals the ratio of the Highly Compensated Employee with the next highest actual deferral ratio. This "leveling" process will be repeated until the ADP test is satisfied.

Highly Compensated Employee Participants whose Before-Tax Option contributions are prospectively limited by this Section B-4 are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation.

If, after the end of the Plan Year, it is determined that the limitation of this Section B-4 has been exceeded, the Plan Administrator may authorize the Trustee to distribute the excess contributions and the income or loss allocable thereto to the Highly Compensated Employees with the highest dollar deferral amounts. Excess contributions are determined by first determining how much the actual deferral ratio of the Highly Compensated Employee with the highest actual deferral ratio would have to be reduced to satisfy the ADP test or cause such ratio to equal the actual deferral ratio of the Highly Compensated Employee with the next highest ratio. Second, this process is repeated until the ADP test would be satisfied. The amount of excess contributions is equal to the sum of these hypothetical reductions multiplied by the Highly Compensated Employee's Compensation. Excess contributions shall be distributed or recharacterized as contributions under the After-Tax Option (each as set forth below), starting with the Highly Compensated Employee with the greatest dollar amount of contributions under the Before-Tax Option during the Plan Year until the amount of excess contributions has been accounted for. At the discretion of the Plan Administrator, the excess contributions may be distributed on or before March 15th following the end of the Plan Year for which the limitation of this Section B-4 is exceeded. With respect to the distribution of excess contributions, such distribution may be postponed, but not later than the close of the Plan Year following the Plan Year to which the contributions are allocable. To the extent any Company Matching Contributions were allocable to the Participant's account as a result of excess contributions, such Company Matching Contributions and income or loss allocable thereto will be forfeited and thereafter applied to reduce Company contributions to the Plan.

Distributions required under this Section B-4.2 shall be made first from Participants' Supplemental Contributions made under the Before-Tax Option and income or loss allocable thereto and, thereafter, from Participants' Basic Contributions made under the Before-Tax Option, and income or loss allocable thereto.

Income or loss allocable to excess contributions for the Plan Year will be computed using either a reasonable method that meets the requirements of Treasury Regulation Section 1.401(k)-2(b)(2)(iv)(B) or the fractional method under Treasury Regulation Section 1.401(k)-2(b)(2)(iv)(C). Income allocable to excess contributions shall be determined on a date that is no more than 7 days before such contributions are distributed.

In the event a distribution of excess contributions occurs, the Company will designate that the distribution is comprised of excess contributions and income or loss allocable thereto.

As an alternative to the distribution of amounts exceeding the limitation of this Section B-4.2 after the end of the Plan Year, the Plan Administrator may cause the excess contributions to be recharacterized first as "catch-up contributions" in accordance with, and subject to the limitations of, Section 414(v) of the Code to the extent that the Participant would otherwise be eligible to make such catch-up contributions under Section 3.1(a) of the Plan, and then as contributions under the After-Tax Option. The option to recharacterize excess contributions is provided at the sole discretion of the Plan Administrator.

The limitation set forth in this Section B-4 will be determined and the computation of any distribution or recharacterization of contributions required under this Section B-4.2 will be made after adjustments are made to contributions under the Before-Tax Option as necessary to avoid exceeding the Code Section 402(g) dollar limitations on contributions as provided in Section B-1.

It is the intent of the Plan that the limitations set forth in Section B-4.1 and the corrective measures set forth in Section B-4.2 will conform to the respective provisions of Code Section 401(k) and the accompanying regulations. As of the date of any adjustment in the limitations prescribed by Code Section 401(k), the provisions of this Section B-4 will be deemed to have been amended to reflect such adjustment.

B-5 Limitation on Participant Contributions Under the After-Tax Option and Company Matching Contributions (ACP Test)

B-5.1 Maximum Annual Contribution – For each Plan Year, the actual contribution percentage (ACP) for the group of Highly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year shall not exceed the greater of:

(1) 125 percent of the actual contribution percentage for the group of Nonhighly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year; or

(2) the lesser of (a) 200 percent of the actual contribution percentage for the group of Nonhighly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year, or (b) the actual contribution percentage for the group of Nonhighly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year plus two (2) percentage points.

In determining whether the Plan satisfies the limitation under this Section B-5, all employee and matching contributions that are made to the Plan and any other plans of the Employer that are aggregated with the Plan for purposes of Code Sections 401(a)(4) and 410(b) (other than Code Section 410(b)(2)(A)(ii)), are to be treated as made under a single plan. If the Plan and any other plans of the Employer are permissively aggregated for purposes of satisfying this limitation under Section B-5, the aggregated plans must also satisfy Code Sections 401(a)(4) and 410(b) as though they were a single plan.

For purposes of this Section, "actual contribution percentage" for a Plan Year means, with respect to the group of Highly Compensated Employees who are eligible to participate through the After-Tax and/or Before-Tax Options and the group of Nonhighly Compensated Employees who are eligible to participate through the After-Tax and/or Before-Tax Options for the Plan Year, the average of the actual contribution ratios, calculated separately for each Employee who is eligible to participate through the After-Tax and/or Before-Tax Options for the Plan Year in each group.

The "actual contribution ratio" for each such Employee is equal to the sum of their annual Participant contributions under the After-Tax Option and the Company Matching Contributions allocated to their accounts, divided by the Participant's Compensation. For purposes of this Section, Compensation generally means an Employee's total Compensation for the Plan Year; however, Compensation does not include amounts related to any portion of the Plan Year in which an Employee was not eligible to participate under the After-Tax Option of the Plan or to have Company Matching Contributions allocated to his account. The actual contribution ratio of a Highly Compensated Employee is determined by treating all plans of the Employer that are subject to Code Section 401(m) under which the Highly Compensated Employee is eligible to participate (other than those that may not be permissively aggregated) as a single plan.

The actual contribution ratio for each Employee who is eligible to participate through the After-Tax and/or Before-Tax Options and the actual contribution percentage for the Highly Compensated Employee group and the Nonhighly Compensated Employee group shall be calculated to the nearest one-hundredth of one percent.

To the extent provided by Treasury regulations, the Plan Administrator may elect to apply the limitation under this Section by including Employee elective deferrals under the Before-Tax Option.

B-5.2 Elimination of Excess Contributions – To prevent the limitation under this Section B-5 from being exceeded in any Plan Year, the Plan Administrator may prospectively limit the rate of contribution which a Highly Compensated Employee may elect to contribute under the After-Tax Option and, if necessary, may reduce amounts which would otherwise be contributed for a Highly Compensated Employee as a Company Matching Contribution.

The Plan Administrator will establish a maximum rate of contribution for Highly Compensated Employees to avoid exceeding the limits of this Section B-5.

The maximum rate of contribution for Highly Compensated Employees will be determined by first reducing by 1/10 of a percent the rate of contribution under the After-Tax Option, and any related Company Matching Contribution, of the Highly Compensated Employees having the highest actual contribution ratio. The rate of contribution will be reduced until the ACP test is satisfied, or until the actual contribution ratio is reduced to the point where it equals the ratio of the Highly Compensated Employee with the next highest actual contribution ratio. This "leveling" process will be repeated until the ACP test is satisfied.

Any After-Tax Option contributions resulting from the recharacterization of Before-Tax Option contributions under the provisions of Section B-4.2 are included in the computation of the actual contribution percentage and are subject to limitation under this Section B-5. If the After-Tax Option contributions of the Highly Compensated Employee with the highest average contribution ratio have been reduced to zero, and further reduction is necessary to avoid exceeding the limitation, then Company Matching Contributions relating to Before-Tax Option contributions will be reduced also.

Highly Compensated Employees whose After-Tax Option contributions are limited by this Section B-5, may elect to either prospectively increase their contributions under the Before-Tax Option or increase their cash compensation by an amount equal to the percentage of Eligible Compensation in excess of the limitation. If the Participant fails to make an election regarding such excess, the excess will be paid to the Participant as cash compensation. Any recharacterization elected by the Participant will be permitted only if it does not cause any other limitations described in Appendix B to be exceeded.

If, after the end of the Plan Year, it is determined that the limitation of this Section B-5 has been exceeded, the Plan Administrator may authorize the Trustee to distribute the excess aggregate contributions and income or loss allocable thereto to the Highly Compensated Employees with the highest dollar contribution amounts. Excess contributions are determined by first determining how much the actual contribution ratio of the Highly Compensated Employee with the highest actual contribution ratio would have to be reduced to satisfy the ACP test or cause such ratio to equal the actual contribution ratio of the Highly Compensated Employee with the next highest ratio. Second, this process is repeated until the ACP test would be satisfied. The amount of excess contributions is equal to the sum of these hypothetical reductions multiplied by the Highly Compensated Employee's Compensation. Excess contributions shall be distributed as set forth below, starting with the Highly Compensated Employee with the greatest dollar amount of contributions under the After-Tax Option during the Plan Year until the amount of excess contributions has been accounted for. At the discretion of the Plan Administrator, the excess aggregate contributions may be distributed on or before March 15th following the end of the Plan Year for which the limitation of this Section B-5 was exceeded. With respect to the distribution of excess aggregate contributions, such distribution may be postponed, but not later than the close of the Plan Year following the Plan Year to which the contributions are allocable.

Distributions required under this Section B-5.2 shall be made first from Participants' Supplemental Contributions made under the After-Tax Option and income or loss allocable thereto, and, thereafter, from Basic Contributions made under the After-Tax Option and income or loss allocable thereto, and Company Matching Contributions and income or loss allocable thereto.

Income or loss allocable to excess aggregate contributions for the Plan Year will be computed using either a reasonable method that meets the requirements of Treasury Regulation Section 1.401(m)-2(b)(2)(iv)(B) or the fractional method under Treasury Regulation Section 1.401(m)-2(b)(2)(iv)(C). Income allocable to excess aggregate contributions shall be determined on a date that is no more than 7 days before such contributions are distributed.

In the event a distribution of excess aggregate contributions occurs, the Company will designate that the distribution is comprised of excess aggregate contributions and income or loss allocable thereto.

The limitation of this Section B-5 will be determined and the computation of any distribution of contributions required under this Section B-5.2 will be made after adjustments are made to contributions under the Before-Tax Option as necessary to avoid exceeding Code Section 402(g) dollar limitations on contributions as provided in Section B-1 or the Code Section 401(k) limitations on contributions as provided in Section B-4.

It is the intent of the Plan that the limitations set forth in Section B-5.1 and the corrective measures set forth in Section B-5.2 will conform to the respective provisions of Code Section 40l(m) and the accompanying regulations. As of the date of any adjustment in the limitations prescribed by Code Section 40l(m), the provisions of this Section B-5 will be deemed to have been amended to reflect such adjustment.

B-6 Gap Period Income on Excess Contributions and Excess Aggregate Contributions — The Plan Administrator will not calculate and distribute allocable income for the gap period (*i.e.*, the period after the close of the Plan Year in which the excess contribution or excess aggregate contribution occurred and prior to the distribution). For purposes of this Appendix B-6, the term excess contribution is defined as in Code Section 401(k)(8)(B) and excess aggregate contribution is defined as in Code Section 401(m)(6)(B).

APPENDIX C

EMPLOYEE SAVINGS PLAN
BONUSES AND INCENTIVES
INCLUDABLE IN BASIC COMPENSATION
FOR PARTICIPATING EMPLOYERS

The base rate of pay in the calculation of Eligible Compensation paid by the Participating Employer to an Employee includes the following:

- NRC License Bonus
- Electrician License Bonus
- Plumber License Bonus
- Service Operators Bonus
- Outage Schedulers Bonus
- Fire and Safety Responder (FASER) Bonus

The following bonuses and/or incentive awards paid by the respective Participating Employers are includable in the calculation of Eligible Compensation for purposes of determining a Participant's After-Tax and Before-Tax Option contributions and Company Matching Contributions:

1. Annual Bonuses*
2. Annual Incentive Award (excluding Nine Mile Point Nuclear Station, LLC)*
3. Annual Performance Award*
4. Commission Payments
5. Contract Incentive Rate Award
6. Emergency Work Payment
7. Lump Sum Pay Adjustments
8. Piece Work Payment
9. Promotion Recognition Award
10. Reliability Award*
11. Results Incentive Award*
12. Sales Bonus

13. Sales Incentive Award

14. Scale Rate Payment

* Prior to January 1, 2004, each Participant employed by the applicable Participating Employer may elect to exclude the indicated bonus/award from Eligible Compensation, pursuant to an election which may be made available to all Employees of such Participating Employer at the Plan Administrator's discretion.

APPENDIX D

TOP HEAVY PROVISIONS

D-1 Purpose – If the Plan is or becomes top-heavy in any Plan Year, the following provisions will supersede any conflicting provisions in the Plan.

D-2 Definitions – As used in the Plan, the following terms shall have the meaning set forth below, unless a different meaning is clearly required by the context in which the term is used.

D-2.1 RESERVED

D-2.2 "Anniversary Date" means December 31, the last day of the Plan Year.

D-2.3 "Controlled Group" shall mean any group of corporations, partnerships or proprietorships which, together with the Company, are members of a Controlled Group within the meaning of Code Section 1563(a), determined without regard to Code Section 1563(a)(4) or (e)(3)(C) or would be a part of such a group if Code Section 1563(a) applied to partnerships or proprietorships.

D-2.4 "Key-Employee" shall mean any person who meets the requirements of Code Section 416(i), and the regulations promulgated thereunder, which are hereby incorporated by reference as if fully set out herein. For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term Key-Employee shall also include the beneficiary of a Key-Employee.

D-2.5 "Permissive Aggregation Group" shall mean all plans in the Required Aggregation Group and any other Qualified Plan maintained by the Company or by any member of the Controlled Group or Affiliated Service Group, but only if such group of plans would satisfy, in the aggregate, the requirements of Code Sections 401(a)(4) and 410 and contributions or benefits in the other Qualified Plans are comparable to contributions or benefits in the plans of the Required Aggregation Group. The Plan Administrator shall determine which plan or plans shall be taken into account in determining the Permissive Aggregation Group.

D-2.6 "Qualified Plan" shall mean any plan which is qualified under Code Section 401(a).

D-2.7 "Required Aggregation Group" shall mean:

(a) Each Qualified Plan of the Company or any member of the Controlled Group or the Affiliated Service Group in which at least one (1) Key-Employee participates; and

(b) Any other Qualified Plan of the Company or any member of the Controlled Group or the Affiliated Service Group which enables a Plan described in Section D-2.7(a) to meet the requirements of Code Sections 401(a)(4) and 410.

D-2.8 "Top-Heavy Plan" shall mean the Plan, for any Plan Year in which the Plan meets the requirements of Section D-3.2.

D-3 Top-Heavy Plan Requirements and Determination

D-3.1 Top-Heavy Plan Requirements – For any Plan Year in which the Plan is determined to be a Top-Heavy Plan in accordance with Section D-3.2, the Plan shall be subject to the following:

(a) special vesting requirements of Code Section 416(b); and

(b) special minimum allocation requirements of Code Section 416(c).

D-3.2 Top-Heavy Plan Determination

(a) The Plan shall be considered a Top-Heavy Plan and shall be subject to the additional requirements of Section D-3.1, with respect to any Plan Year, if, as of the Anniversary Date of the preceding Plan Year (hereinafter referred to as the "determination date") either:

(i) the sum of the value of the aggregate accounts of Key-Employees exceeds sixty percent (60%) of a similar sum determined for all Participants (the "60% Test"); or

(ii) the Plan is part of a Required Aggregation Group, and the sum of the present value of accrued benefits and the value of the aggregate accounts of Key-Employees in all Plans in such group exceeds sixty percent (60%) of a similar sum determined for all Participants.

(b) For purposes of this Section D-3.2, the aggregate account of a Participant as of the determination date is the sum of:

(i) the Company Matching Contribution Account and Employee Stock Account of such Participant as of the determination date adjusted for any contributions due as of the determination date, and further adjusted by including any Plan distributions made during a (1) year period ending on the most recent determination date, except that in the case of any distribution made for a reason other than severance from employment, death, or disability, this provision shall be applied by substituting five (5) year period for (1) year period; and

(ii) the Participant Contribution Account of such Participant.

(c) For purposes of this Section D-3.2, present value of accrued benefits shall be determined, in the case of a defined benefit pension plan, under the provisions of such a plan or plans.

(d) Notwithstanding the provisions of subsection (a) hereinabove, the Plan shall not be a Top-Heavy Plan, if the Plan Administrator elects to treat the Plan as part of a Permissive Aggregation Group, and the Permissive Aggregation Group is not determined to be Top-Heavy using the criteria of the "60% Test" hereinabove.

(e) Only those plans in which the determination dates fall within the same calendar year shall be included in a Required or a Permissive Aggregation Group in order to determine whether the Plan is a Top-Heavy Plan.

(f) The account (and any accrued benefit) of an individual who has not performed services for the Employer at any time during the one (1) year period ending on the determination date shall not be taken into account for purposes of Section D-3.2.

D-4 Additional Top-Heavy Provisions – For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term "Participant" as defined in Appendix A of the Plan shall also include the beneficiary of a Participant.

Notwithstanding the provisions in Section 3.2(a) regarding the rate of Company Matching Contributions, for any Plan Year in which the Plan, or any Permissive or Required Aggregation Group of which this Plan is a member, is a Top-Heavy Plan, the Company contributions to provide the minimum allocation or benefit requirement applicable to Top-Heavy Plans for allocation on behalf of any Participant who is not a Key-Employee and who is employed by the Company on the last day of the Plan Year will be provided under the Company's defined benefit pension plan. In the event the Company's defined benefit pension plan should be amended to not include the above minimum allocation or benefit requirement, then the minimum allocation or benefit will be provided under this Plan less any Company contribution that might be provided in any other Company defined contribution plan pursuant to Code Section 416(c).

APPENDIX E

PARTICIPATING EMPLOYERS

The following Employers are Participating Employers as of the corresponding effective dates:

Participating Employers	Employer Code	Participation Effective Date
(a) Baltimore Gas and Electric Company	001	July 1, 1978
(b) BGE Home Products & Services, LLC (formerly known as BGE Home Products & Services, Inc.)	006	July 1, 1994
(c) CER Generation, LLC	464	February 14, 2008
(d) CNE Gas Holdings, Inc. (formerly known as Fellon-McCord Associates, Inc.)	035	January 1, 2003
(e) Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.)	013	March 1, 1997
(f) Constellation Energy Group, Inc.	018	April 30, 1999
(g) Constellation Energy Projects and Services Group Advisors, LLC	603	March 28, 2011
(h) Constellation Energy Projects and Services Group, Inc. (formerly known as Constellation Energy Source, Inc.)	011	December 1, 1995
(i) Constellation NewEnergy, Inc.	034	September 1, 2002

Special Provisions:

- Under Section 3.3, Participants who are active employees of Constellation NewEnergy, Inc. on the date of the closing of the transaction contemplated in the Stock Purchase Agreement, may also roll over as part of a distribution from the AES Corporation Profit Sharing and Stock Ownership Plan ("DC Plan") notes evidencing such employee's DC Plan loans and the portion of such distribution that is not includable in gross income.

- Under Section 7.1(c), rollover of a distribution from the DC Plan for Participants who are active employees of Constellation NewEnergy, Inc. on the date of the closing of the transaction contemplated in the Stock Purchase Agreement mature immediately.

(j) Constellation Operating Services	023	April 1, 2003
(k) Constellation Power, Inc.	014	June 1, 1998
(l) Constellation Power Source Generation, Inc.	028	April 1, 2001
(m) COSI Sunnyside, Inc.	024	April 1, 2003

The following Employers were Participating Employers as of the corresponding effective dates, but are no longer:

Participating Employers	**Employer Code**	**Participation Effective Date**
(a) BGE Commercial Building Systems, Inc.	008	January 1, 1996 through October 31, 2003
(b) Constellation Investments, Inc.	012	January 1, 1997 through December 31, 1999
(c) Constellation Operating Services, Inc.	029	April 1, 2003 through October 1, 1999
(d) Constellation Power Source Holdings, Inc.	032	July 1, 2000
(e) Constellation Real Estate, Inc.	017	April 1, 2001 through December 31, 2003
(f) COSI Central Wayne, Inc. (Employees represented by a union under a collective bargaining agreement are not eligible to participate.)	021	April 1, 2003 through September 8, 2003
(g) COSI Puna, Inc.	022	April 1, 2003 through June 6, 2004
(h) COSI Synfuels, Inc.	025	April 1, 2003 through June 10, 2008

(i)	PCI Operating Company Partnership	026	April 1, 2003 through March 31, 2008
(j)	Robinson Bend Operating Two, LLC	349	November 14, 2005 through November 12, 2006

Exhibit 10.69

**FIRST AMENDMENT TO THE
CONSTELLATION ENERGY GROUP, INC.
EMPLOYEE SAVINGS PLAN**

(Amended and Restated Effective January 31, 2012)

WHEREAS, Exelon Corporation (the "Company") sponsors the Constellation Energy Group, Inc. Employee Savings Plan for (Amended and Restated Effective as of January 31, 2012) (the "Plan"), which is intended to meet the requirements of the provisions of the Internal Revenue Code of 1986, (as amended) (the "Code"); and

WHEREAS, the Company desires to amend the Plan in certain respects; and

WHEREAS, pursuant to Section 12.1 of the Plan the Chief Human Resources Officer may authorize any amendment to the Plan that does not increase Plan liabilities materially;

NOW, THEREFORE, BE IT RESOLVED, that the Plan is hereby amended as follows, effective January 1, 2012:

1. By adding a new paragraph at the end of Section 11.5(a) as follows:

   Notwithstanding the foregoing, with respect to a tender offer for the purchase or exchange of less than five percent (5%) of the outstanding shares of Common Stock, the Company shall direct the Trustee with respect to the sale, exchange or transfer of the shares of Common Stock held in the Trust Fund, and the Trustee shall follow the direction of the Company.

****

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President & Chief Human Resources Officer, on this _____ day of June, 2012.

EXELON CORPORATION

By: ______________________________

Senior Vice President &
Chief Human Resources Officer

Exhibit 10.70

SECOND AMENDMENT TO THE CONSTELLATION ENERGY GROUP, INC. EMPLOYEE SAVINGS PLAN

(Amended and Restated Effective January 31, 2012)

WHEREAS, Exelon Corporation (the "Company"), a Pennsylvania corporation, sponsors and maintain a qualified retirement plan for the benefit of employees of the Company and certain of its subsidiaries titled, "Constellation Energy Group, Inc. Employee Savings Plan" (the "Plan"), which has been amended and restated effective as of January 31, 2012;

WHEREAS, the Company has entered into that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation (the "Merger Sub") and Constellation Energy Group, Inc. ("Constellation") (the "Merger Agreement");

WHEREAS, pursuant to the Merger Agreement, the Merger Sub merged with and into Constellation and the separate existence of the Merger Sub ceased; Constellation merged with and into Exelon, and the separate existence of Constellation ceased; and Exelon continued as the surviving corporation; and

WHEREAS, the Company desires to amend the Plan to restrict participation in the Plan to individuals participating in the Plan immediately before the Effective Time (as such term is defined in the Merger Agreement) and to other eligible individuals who are initially employed on or after the Effective Time at a facility owned immediately before the Effective Time by: (i) the Constellation, or (ii) an affiliate that was an affiliate of Constellation immediately before the Effective Time; and

WHEREAS, the Company desires to amend the Plan in certain aspects to resemble more closely the Company's Employee Savings Plan, a profit sharing plan with a qualified cash or deferred arrangement, and to reflect the Company's administrative and fiduciary practices;

WHEREAS, pursuant to the January 24, 2012 resolutions of the Company Board of Directors, Company officers are authorized to take such actions and execute such documents, including amendments to the Constellation plan as deemed necessary to meet the goals set forth therein;

NOW, THEREFORE, BE IT RESOLVED, that the Plan is hereby amended as follows, effective as of the Effective Time, unless otherwise noted:

1. By replacing the word "CEG" with the word "Company" in the phrases "CEG Common Stock" and "CEG Common Stock Fund" in each instance that it appears.

2. By adding a sentence to the end of Section 1.1, as follows:

> Effective as of the Effective Time, shares of common stock of Constellation Energy Group, Inc. were converted to common shares of Exelon Corporation, pursuant to the Merger Agreement, at a conversion rate of .9300. Effective January 1, 2013, the Plan is designated as a "profit sharing plan" within the meaning of section 1.401-1(a)(2)(ii) of the Regulations; and is also designated as an ERISA section 404(c) Plan within the meaning of section 2550.404c-1 of the Regulations.

3. Effective January 1, 2013, by adding the phrase "and Profit Sharing Matching Contributions" after the phrase "Company Matching Contributions" in the third sentence of Section 1.2.

4. Effective January 1, 2013, by renaming Section 1.3(c) from "Company Matching Contributions" to "Employer Contributions" and adding a second paragraph to the end of the section, as follows:

In addition, and likewise subject to the limitations of Articles III and IV and Appendix B of the Plan, each Participant shall be eligible to receive a Profit Sharing Matching Contribution, provided that such Participant either (i) is an Employee on the last day of such Plan Year, (ii) is not employed on such day as a result of an approved unpaid leave of absence during such Plan Year, (iii) terminates employment during such Plan Year (1) after attaining age 50 and completing at least 10 years of service, as determined by the Plan Administrator, (2) as a result of circumstances entitling the Participant to separation benefits under an Employer's severance benefit plan, (3) as a result of a disability that entitles the Participant to benefits under an Employer's long-term disability plan, or (4) on account of the Participant's death. Participants shall be eligible for Matching Contributions beginning with any such contribution made in 2014 based on Plan Year 2013 performance in accordance with Section A-48(a).

5. By adding a new section 2.1(d), as follows:

2.1(d) Effect of Merger Agreement

If an Employee who was an Employee on or prior to the Effective Time transfers employment to or is reemployed by Exelon in a job classification with respect to which similarly situated employees of Exelon are not eligible to participate in the Plan but are instead eligible to participate in a Parent Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be qualified under Section 401(a) or 401(k) of the Code (each such plan, an "Exelon Retirement Plan"), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Exelon Retirement Plan. If a participant in an Exelon Retirement Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by a Participating Employer in a job classification with respect to which similarly situated employees of such Participating Employer are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the Exelon Retirement Plan and shall not participate in the Plan.

6. Effective January 1, 2013, by deleting and replacing the first sentence of Section 3.1(e) as follows:

> An authorized leave of absence shall not constitute a termination of employment, but shall, except as provided in Section 3.1(f), operate to suspend Participant contributions, related Company Matching Contributions, and Profit Sharing Matching Contributions (the latter as set forth in Section 1.3(c)).

7. Effective January 1, 2013, by adding a new sentence immediately before the last sentence in the first paragraph of Section 3.1, as follows:

> A Profit Sharing Matching Contribution will be made in accordance with Section 3.3.

8. Effective January 1, 2013, by adding a new Section 3.3, as follows, and re-numbering the subsequent sections:

> **3.3 Profit Sharing Matching Contributions**
>
> Beginning with any Profit Sharing Matching Contribution made in 2014 based on Plan Year 2013 performance in accordance with Section A-48(a) and subject to the limitations described in Article IV and Appendix B, the Company will contribute the Profit Sharing Matching Contribution to the Plan on behalf of each Participant at its discretion.
>
> Profit Sharing Matching Contributions will be made completely in cash and are invested in the Investment Funds designated by the Participant.

9. Effective 1/1/2012, by adding a sentence after the first sentence of current Section 3.3 (to be renumbered as Section 3.4), and correcting any cross-references to former section 3.3, as follows:

> A Participant who rolls over an Eligible Rollover Distribution from a qualified retirement plan, or on whose behalf a direct transfer is made, in conjunction with a corporate transaction shall also be permitted to rollover or transfer in-kind any promissory notes evidencing any loans under that plan, to the extent the agreement memorializing the transaction so provides.

10. By replacing the phrase “Investment Committee” with the phrase “Investment Office” in Sections 5.1(a)(3) and 13.1.

11. Effective January 1, 2013, reference to “Company Matching Contributions” and “Company Matching Contributions Account” shall be replaced by reference to “Employer Contributions” and “Employer Contribution Account” in Sections 4.1, 4.2(b), 4.2(d), 5.1(a), the heading and Paragraph 2 of 5.1(d), 5.2(b), 5.3(a), 6.2), 7.1(c), 7.3(c), 7,4, 8,2(b), 8.4(b), 8.4(c), 8.6, 9.5, 11.4, 11.5(a), 11.5(b), 12.2), Appendix B-1, Appendix B-4.2, Appendix B-5, Appendix C, Appendix D-3.2(b)(i), Appendix D-4

12. Effective January 1, 2013 by deleting “As with Company Matching Contributions,” from the last sentence of Section 5.1(e).

13. By deleting Sections 10.1, 10.2, 10.3, 10.4, 10.5, 10.7 and 10.8, and replacing them as follows, and re-numbering the remaining, subsequent sections:

Section 10.1 The Plan Administrator, the Investment Office and the Corporate Investment Committee.

10.1(a) The Plan Administrator

The Company, acting through its Director, Employee Benefit Plans & Programs, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such director or other person or committee, the “Plan Administrator”), shall be the “administrator” of the Plan, within the meaning of such term as used in ERISA. In addition, the Plan Administrator shall be the “named fiduciary” of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan’s assets. The Plan Administrator shall have the following duties, responsibilities and rights:

(i) The Plan Administrator shall have the duty and discretionary authority to interpret and construe the Plan in regard to all questions of eligibility, the status and rights of Participants, distributees and other persons under the Plan, and the manner, time, and amount of payment of any distribution under the Plan. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Plan Administrator, in its discretion, determines that such person is entitled to benefits.

(ii) The Plan Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 8 (relating to withdrawals and distributions).

(iii) The Plan Administrator shall supervise the collection of Participants' contributions made pursuant to Article 5 (relating to Employee contributions) and the delivery of such contributions to the Trustee.

(iv) The Plan Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) Each Employer shall, from time to time, upon request of the Plan Administrator, furnish to the Plan Administrator such data and information as the Plan Administrator shall require in the performance of its duties.

(vi) The Plan Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Plan Administrator and to furnish such information requested by the Plan Administrator. The Plan Administrator and the Plan may rely upon all such information so furnished to the Plan Administrator.

(vii) The Plan Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

10.1(b) Removal of Plan Administrator

The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Plan Administrator (including any member of a committee that constitutes the Plan Administrator). The Plan Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Plan Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Plan Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Plan Administrator.

10.1(c) The Investment Office

The Investment Office, shall be the “named fiduciary” of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Sections 404(a)(2) and 404(c) of ERISA, the terms of the Plan, and all other applicable limitations. The Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the “named fiduciary” for purposes of designating the investment funds under Section 6.2 and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall be solely responsible for all matters involving investment of the Employer Stock Fund described in Section 6.2 and no other person shall have any responsibility with respect to investment of such fund; provided, however, that effective June 21, 2012, the Investment Office has appointed an independent investment manager under section 3(38) of ERISA to manage the investment of the Common Stock in the Company Common Stock Fund and such investment manager (rather than the Investment Office) shall be solely responsible for any and all investment decisions relating thereto.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

10.1(d) The Corporate Investment Committee

The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee and the Company’s Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and the Corporate Investment Committee shall have no other duties or responsibilities with respect to the Plan. None of the Company, any officer employee, or member of the board of directors who is not a member of the Corporate Investment Committee, nor any other person shall have any responsibility regarding the appointment or removal of the employees of Investment Office.

10.1(e) Status of Plan Administrator, the Investment Office and the Corporate Investment Committee

The Plan Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Plan Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Plan Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

10.1(f) Notice to Trustee of Members

The Trustee shall be notified as to the names of the Plan Administrator and the person or persons authorized to act on behalf of the Investment Office.

10.1(g) Allocation of Responsibilities

Each of the Plan Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

10.1(h) General Governance

The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Plan Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

10.1(i) Indemnification

The Employers hereby jointly and severally indemnify the Plan Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

10.1(j) No Compensation

None of the Plan Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Plan Administrator, the Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Employer for compensation paid to any such person if such compensation constitutes “direct expenses” for purposes of ERISA. The Employers shall reimburse the Plan Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

10.1(k) Employ of Counsel and Agents

The Plan Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

10.2 Claims Procedure

Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Plan Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Plan Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Plan Administrator’s decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Plan Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Plan Administrator expects to render the benefit determination. The notice of the decision of the Plan Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Plan Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Sections 13.11 and 13.13) to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The Plan Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the by the Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to such officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by such officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the reviewing officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

14. By deleting paragraph 1 of current Section 10.6 (now renumbered 10.3), and replacing it in its entirety as follows:

Except as provided below (relating to expenses of various investments), all costs and expenses incurred in administering the Plan and the Trust, including, but not limited to, "direct expenses" incurred in administering the Plan and the Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust), the expenses of the Plan Administrator and the Investment Office, the fees of counsel and any agents for the Plan Administrator and the Investment Office, the fees and expenses of the Trustee, the fees of counsel for the Trustee and other administrative expenses shall, to the extent permitted by law, be paid from the Trust Fund to the extent such expenses are not paid by the Participating Employers. Notwithstanding the foregoing, the Plan Administrator may authorize

Employer to pay any expenses, and Employer shall be reimbursed from the Trust Fund for such payments. The Plan Administrator, in its discretion, having regard to the nature of a particular expense, shall determine the portion of the expense that is to be borne by each Participating Employer.

16. By deleting paragraph 5 of Section 10.6 (now renumbered 10.3) and replacing it in its entirety as follows:

None of the Plan Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Plan Administrator, the Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Employer for compensation paid to any such person if such compensation constitutes “direct expenses” for purposes of ERISA. The Employers shall reimburse the Plan Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

17. By deleting the first five sentences of Section 12.1, and replacing them as follows:

The Company may at any time and from time to time amend or modify the Plan by resolution of the Board of Directors of the Company or the Compensation Committee thereof; provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility.

18. By adding the following sentence to the end of Section 13.2(b), as follows:

A Participant who submits a qualified domestic relations order for certification may be charged an order processing fee, as determined from time to time by the Plan Administrator, which will be deducted from the Participant’s Plan account balance in the same manner set forth in Section 9.5.

19. By inserting new Sections 13.11, 13.12, and 13.13 as follows:

13.11 Statute of Limitations for Actions under the Plan

Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Company's Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

13.12 Forum for Legal Actions under the Plan.

Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the District of Maryland.

13.13 Legal Fees.

Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Vice President, Health & Benefits, any Plan fiduciary, the Chief Human Resources Officer, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

20. By deleting the definition set forth in Section Appendix A-1, and labeling it "Reserved," and deleting references to the "Administrative Committee" from Sections 13.1 and 13.5.

21. By deleting the definition set forth in Section Appendix A-17, and labeling it "Reserved."

22. By adding a new Section Appendix A-14(a), immediately after Appendix A-14, as follows:

14(a) “Corporate Investment Committee” means the Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

23. By deleting the definition set forth Section Appendix A-28 and labeling it “Reserved,” all deleting all references to the “Executive Group.”

24. By adding a new section Appendix A-20(a), immediately after Appendix A-20, as follows:

20(a) “Effective Time” means the effective time of the transaction that is the subject of the Merger Agreement, as such term is defined in the Merger Agreement.

25. By adding a new section Appendix A-28(a), immediately after Appendix A-28, as follows:

28(a) “Exelon” means Exelon Corporation and any of its affiliates that was an affiliate immediately before the Effective Time.

26. By adding a new section Appendix A-34(a), immediately after Appendix A-34, as follows:

34(a) “Merger Agreement” means that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

27. By adding a sentence after the first sentence of section Appendix A-24, as follows:

Effective as of the Effective Time, Employee shall not include any person who was: (i) employed immediately prior to the Effective Time at Exelon or a facility owned immediately before the Effective Time by Exelon or (ii) initially employed on or after the Effective Time at a facility owned immediately before the Effective Time by Exelon.

28. By replacing section Appendix A-47 in its entirety as follows:

47 “Plan Administrator” means the Director, Employee Plans and Programs of Exelon (or the position succeeding to that function).

29. By deleting Section Appendix A-33 and replacing it with a new section Appendix A-33, as follows:

33 “Investment Office” mean the Company acting through the Exelon Investment Office.

30. By adding a new section Appendix A-14(a), as follows, and adding the word “Corporate” in front of the words “Investment Committee” in Sections 5.1(a)(3), 13.1 and 13.5:

14(a) “Corporate Investment Committee” means the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

31. Effective January 1, 2013, by adding a new Section Appendix A-48(a), as follows:

48(a) “Profit Sharing Matching Contribution” means an amount (if any) determined by the Board of Directors of the Company (or the Compensation Committee thereof) in its sole discretion based on attainment of specified performance goals, and not exceeding one-half of each Participant’s Basic Contribution.

32. Effective January 1, 2013, by adding a new section Appendix A-26(a), as follows:

26(a) “Employer Contribution” means the aggregate of Company Matching Contributions and Profit Sharing Matching Contributions.

33. By adding a sentence to the end of the footnote in Appendix C as follows:

Effective on and after January 1, 2013, bonuses indicated by an asterisk (*) payable in 2014 and thereafter shall no longer be Eligible Compensation.

34. By amending Appendix E to add the following:

(n) Exelon Business Services Corporation [1]

(o) Exelon Generation Company, LLC[2]

1 For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.
2 For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.

****

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President, Human Resources, on this ____ day of December, 2012.

EXELON CORPORATION

____
Amy E. Best
Senior Vice President and
Chief Human Resource Officer

Exhibit 12.1

Exelon Corporation
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	4,418	4,221	3,952	1,798	2,773
Plus: Loss from equity investees	27	—	1	91	(10)
Less: Capitalized interest	(55)	(43)	(57)	(75)	(67)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	4,390	4,178	3,896	1,814	2,696
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	761	836	761	1,021	1,436
Interest component of rental expense (a)	230	241	237	310	269
Total fixed charges	991	1,077	998	1,331	1,705
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	5,381	5,255	4,894	3,145	4,401
Ratio of earnings to fixed charges	5.4	4.9	4.9	2.4	2.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Corporation
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	4,418	4,221	3,952	1,798	2,773
Plus: Loss from equity investees	27	—	1	91	(10)
Less: Capitalized interest	(55)	(43)	(57)	(75)	(67)
Preference security dividend requirements	(7)	(7)	(6)	(26)	(32)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	4,383	4,171	3,890	1,788	2,664
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	761	836	761	1,021	1,436
Interest component of rental expense (a)	230	241	237	310	269
Preference security dividend requirements of consolidated subsidiaries	7	7	6	26	32
Total fixed charges	998	1,084	1,004	1,357	1,737
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	5,381	5,255	4,894	3,145	4,401
Ratio of earnings to fixed charges and preferred stock dividends	5.4	4.8	4.9	2.3	2.5

Exhibit 12.2

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	3,555	3,150	2,827	1,058	1,675
Plus: (Income) or loss from equity investees	3	—	1	91	(10)
Less: Capitalized interest	(49)	(38)	(49)	(67)	(54)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	3,509	3,112	2,779	1,082	1,611
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	162	191	219	402	445
Interest component of rental expense (a)	212	222	220	291	248
Total fixed charges	374	413	439	693	693
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	3,883	3,525	3,218	1,775	2,304
Ratio of earnings to combined fixed charges	10.4	8.5	7.3	2.6	3.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.3

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	602	693	666	618	401
Plus: Loss from equity investees	—	—	—	—	—
Less: Capitalized interest	(3)	(2)	(4)	(3)	(5)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	599	691	662	615	396
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness (a)	301	368	330	297	575
Interest component of rental expense (b)	7	6	6	6	5
Total fixed charges	308	374	336	303	580
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	907	1,065	998	918	976
Ratio of earnings to fixed charges	2.9	2.8	3.0	3.0	1.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

(b) Includes interest expense of $294 million for the year ended December 31, 2013, related to the remeasurement of the like-kind exchange tax position. See Note 14 — Income taxes of the Exelon Form 10-K for the year ended December 31, 2013, for additional information regarding the like-kind exchange tax position.

Exhibit 12.4

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	499	476	535	508	557
Plus: Loss from equity investees	24	—	—	—	—
Less: Capitalized interest	(2)	(4)	(4)	(2)	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	521	472	531	506	555
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	185	193	135	122	114
Interest component of rental expense (a)	9	10	9	9	7
Total fixed charges	194	203	144	131	121
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	715	675	675	637	676
Ratio of earnings to combined fixed charges	3.7	3.3	4.7	4.9	5.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	499	476	535	508	557
Plus: Loss from equity investees	24	—	—	—	—
Less: Capitalized interest	(2)	(4)	(4)	(2)	(2)
Preference security dividend requirements	(6)	(6)	(6)	(5)	(10)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	515	466	525	501	545
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	185	193	135	122	114
Interest component of rental expense (a)	9	10	9	9	7
Preference security dividend requirements	6	6	6	5	10
Total fixed charges	200	209	150	136	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	715	675	675	637	676
Ratio of earnings to fixed charges and preferred stock dividends	3.6	3.2	4.5	4.6	5.2

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.5

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	155	244	211	11	344
Less: Capitalized interest	(4)	(6)	(7)	(5)	(6)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	151	238	204	6	338
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	148	137	136	149	127
Interest component of rental expense (a)	5	4	5	4	4
Total fixed charges	153	141	141	153	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	304	379	345	159	469
Ratio of earnings to fixed charges	2.0	2.7	2.4	1.0	3.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	155	244	211	11	344
Less: Capitalized interest	(4)	(6)	(7)	(5)	(6)
Preference security dividend requirements	(22)	(20)	(20)	(20)	(21)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	129	218	184	(14)	317
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	148	137	136	149	127
Interest component of rental expense (a)	5	4	5	4	4
Preference security dividend requirements	22	20	20	20	21
Total fixed charges	175	161	161	173	152
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	304	379	345	159	469
Ratio of earnings to fixed charges and preferred stock dividends	1.7	2.4	2.1	0.9(b)	3.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $14 million to achieve a coverage ratio of 1:1.

Exhibit 21.1

Exelon Corporation

Name	Jurisdiction
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Alta Devices, Inc.	Delaware
APS Constellation, LLC	Delaware
Astrum, Inc.	Delaware
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Canton Crossing District Energy LLC	Delaware
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CCG SynFuel, LLC	Delaware
CD Malacha I, Inc.	Maryland
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Central Wayne Energy Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Colver Limited Partnership	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Long Valley I, Inc.	Maryland
CE Long Valley II, Inc.	Maryland
CE Long Valley Limited Partnership	Maryland
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation II, LLC	Delaware
CER Generation, LLC	Delaware

CER-Colorado Bend Energy LLC	Delaware
CER-Colorado Bend Energy Partners LP	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Oldco, LLC	Maryland
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Conemaugh Fuels, LLC	Delaware
Consert, Inc.	Delaware
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Control and Dispatch, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware

Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Investments, Inc.	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy—Gas Division, LLC	Kentucky
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy Holding, LLC	Delaware
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Operating Services, LLC	Maryland
Constellation Operating Services International	Grand Cayman
Constellation Operating Services International—I	Grand Cayman
Constellation Power International Development, Ltd	Grand Cayman
Constellation Power Source Generation, Inc.	Maryland
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP II Curacao Ltd	Grand Cayman
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CPI OldCo, Inc.	Maryland
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware

ENEH Services, LLC	Delaware
Energy Capital and Services II, Limited Partnership	Massachusetts
Energy Performance Services, Inc.	Pennsylvania
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Exelon AOG Holding #1, Inc.	Delaware
Exelon AOG Holding #2, Inc	Delaware
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Capital Trust I	Delaware
Exelon Capital Trust II	Delaware
Exelon Capital Trust III	Delaware
Exelon Corporation	Pennsylvania
Exelon Edgar	Delaware
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton LLC	Delaware
Exelon Investment Holdings, LLC	Illinois
Exelon Mechanical, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon Ventures Company, LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExGen Renewables I Holding, LLC	Delaware

ExGen Renewables I, LLC	Delaware
ExTel Corporation, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
F & M Holdings Company, L.L.C.	Delaware
Fair Wind Power Partners, LLC	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Fuel Recovery, Inc.	Pennsylvania
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Guatemalan Generating Group—I	Grand Cayman
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
Inter-Power/Ahlcon Partners Limited Partnership	Delaware
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Las Vegas District Energy, LLC	Delaware
Latin American Power Partners Limited	Grand Cayman
Lilly Recovery, Inc.	Pennsylvania
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Low Country Synfuel Holdings, LLC	Delaware
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Malcha Hydro Limited Partnership	Maryland
Maple Coal Company	Pennsylvania
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
Old Hickory District Energy, LLC	Delaware
OMF 11520, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon

Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Palmetto Synfuel Operating Company, LLC	Delaware
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California
Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar I, LLC	Delaware
Residential Solar II, LLC	Delaware
Residential Solar III, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana
RITELine Transmission Development, LLC	Delaware
River Bend I, L.L.C.	Delaware
Roadrunner-I LLC	Minnesota
RSB BondCo LLC	Delaware
S & P Windfarms, LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Safe Harbor Water Power Corporation	Pennsylvania
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Simmons & Eastern, LLC	Delaware
Spruce Equity Holdings, L.P.	Delaware
Spruce Holdings G.P. 2000, L.L.C.	Delaware
Spruce Holdings L.P. 2000, L.L.C.	Delaware
Spruce Holdings Trust	Delaware
Star Electricity, Inc.	Texas
Sunbelt I, L.L.C.	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware

Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally’s Wind Farm LLC	Minnesota
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exhibit 21.2

Exelon Generation Company, LLC

Name	Jurisdiction
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Alta Devices, Inc.	Delaware
APS Constellation, LLC	Delaware
Astrum, Inc.	Delaware
AV Solar Ranch 1, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Canton Crossing District Energy LLC	Delaware
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CCG SynFuel, LLC	Delaware
CD Malacha I, Inc.	Maryland
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Central Wayne Energy Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Colver Limited Partnership	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Long Valley I, Inc.	Maryland
CE Long Valley II, Inc.	Maryland
CE Long Valley Limited Partnership	Maryland
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation II, LLC	Delaware
CER Generation, LLC	Delaware
CER-Colorado Bend Energy LLC	Delaware
CER-Colorado Bend Energy Partners LP	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware

CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Oldco, LLC	Maryland
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
Conemaugh Fuels, LLC	Delaware
Consert, Inc.	Delaware
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Control and Dispatch, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Investments, Inc.	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy—Gas Division, LLC	Kentucky

Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy Holding, LLC	Delaware
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Operating Services, LLC	Maryland
Constellation Operating Services International	Grand Cayman
Constellation Operating Services International—I	Grand Cayman
Constellation Power International Development, Ltd	Grand Cayman
Constellation Power Source Generation, Inc.	Maryland
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP II Curacao Ltd	Grand Cayman
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CPI OldCo, Inc.	Maryland
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware
ENEH Services, LLC	Delaware
Energy Capital and Services II, Limited Partnership	Massachusetts
Energy Performance Services, Inc.	Pennsylvania
Ewington Energy Systems LLC	Minnesota
Exelon AOG Holding #1, Inc.	Delaware
Exelon AOG Holding #2, Inc	Delaware

Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Edgar	Delaware
Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
Fair Wind Power Partners, LLC	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Fuel Recovery, Inc.	Pennsylvania
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Guatemalan Generating Group—I	Grand Cayman
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho

Inter-Power/Ahlcon Partners Limited Partnership	Delaware
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Las Vegas District Energy, LLC	Delaware
Latin American Power Partners Limited	Grand Cayman
Lilly Recovery, Inc.	Pennsylvania
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Low Country Synfuel Holdings, LLC	Delaware
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Malcha Hydro Limited Partnership	Maryland
Maple Coal Company	Pennsylvania
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Old Hickory District Energy, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Palmetto Synfuel Operating Company, LLC	Delaware
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
Pegasus Power Company, Inc.	California
Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar I, LLC	Delaware
Residential Solar II, LLC	Delaware
Residential Solar III, LLC	Delaware
River Bend I, L.L.C.	Delaware
Roadrunner-I LLC	Minnesota
S & P Windfarms, LLC	Minnesota

Sacramento PV Energy, LLC	Delaware
Safe Harbor Water Power Corporation	Pennsylvania
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Simmons & Eastern, LLC	Delaware
Star Electricity, Inc.	Texas
Sunbelt I, L.L.C.	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally’s Wind Farm LLC	Minnesota
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exhibit 21.3

Commonwealth Edison Company

Name	Jurisdiction
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

Exhibit 21.4

PECO Energy Company

Name	Jurisdiction
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware

Exhibit 21.5

Baltimore Gas and Electric Company

Name	Jurisdiction
Baltimore Gas and Electric Company	Maryland
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No.333-181749 and No. 333-183751), on Form S-4 (No.333-175162) and on Form S-8 (No.333-189849, No.333-175162, No.333-127377, No.333-37082 and No.333-49780) of Exelon Corporation of our report dated February 13, 2014 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting of Exelon Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-05) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Exelon Generation Company, LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-181749-04) of Commonwealth Edison Company of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Commonwealth Edison Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-03) of PECO Energy Company of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of PECO Energy Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2014

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-09) of Baltimore Gas and Electric Company of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Baltimore Gas and Electric Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anthony K. Anderson**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anthony K. Anderson

Anthony K. Anderson

DATE: February 3, 2014

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin

Ann C. Berzin

DATE: February 7, 2014

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John A. Canning, Jr.**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John A. Canning, Jr

John A. Canning, Jr.

DATE: February 3, 2014

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane**, do hereby appoint Darryl M. Bradford attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Yves C. de Balmann

Yves C. de Balmann

DATE: February 1, 2014

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis

Nicholas DeBenedictis

DATE: February 7, 2014

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz

Nelson A. Diaz

DATE: February 3, 2014

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin

Sue L. Gin

DATE: February 10, 2014

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Paul Joskow

Paul Joskow

DATE: February 8, 2014

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Robert J. Lawless

Robert J. Lawless

DATE: February 2, 2014

Exhibit 24.11

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Richard W. Mies

Richard W. Mies

DATE: February 10, 2014

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **William C. Richardson**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ William C. Richardson

William C. Richardson

DATE: February 2, 2014

Exhibit 24.13

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.,** do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John W. Rogers, Jr.

John W. Rogers, Jr.

DATE: February 3, 2014

Exhibit 24.14

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Mayo A. Shattuck III

Mayo A. Shattuck III

DATE: February 5, 2014

Exhibit 24.15

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour**, do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Stephen D. Steinour

Stephen D. Steinour

DATE: February 10, 2014

Exhibit 24.16

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James W. Compton

James W. Compton

DATE: February 10, 2014

Exhibit 24.17

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.18

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. Steven Crown

A. Steven Crown

DATE: February 3, 2014

Exhibit 24.19

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis

Nicholas DeBenedictis

DATE: February 7, 2014

Exhibit 24.20

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr,** do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Peter V. Fazio, Jr.

Peter V. Fazio, Jr.

DATE: February 1, 2014

Exhibit 24.21

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin

Sue L. Gin

DATE: February 10, 2014

Exhibit 24.22

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael H. Moskow**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael H. Moskow

Michael H. Moskow

DATE: February 3, 2014

Exhibit 24.23

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien

Denis P. O'Brien

DATE: February 4, 2014

Exhibit 24.24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore**, do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anne R. Pramaggiore

Anne R. Pramaggiore

DATE: January 31, 2014

Exhibit 24.25

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Jesse H. Ruiz**, do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Jesse H. Ruiz

Jesse H. Ruiz

DATE: February 10, 2014

Exhibit 24.26

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams**, do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Craig L. Adams

Craig L. Adams

DATE: February 1, 2014

Exhibit 24.27

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.28

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D'Alessio

M. Walter D'Alessio

DATE: February 3, 2014

Exhibit 24.29

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis

Nicholas DeBenedictis

DATE: February 7, 2014

Exhibit 24.30

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz

Nelson A. Diaz

DATE: February 3, 2014

Exhibit 24.31

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Rosemarie B. Greco

Rosemarie B. Greco

DATE: February 8, 2014

Exhibit 24.32

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Charisse R. Lillie

Charisse R. Lillie

DATE: February 1, 2014

Exhibit 24.33

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien

Denis P. O'Brien

DATE: February 4, 2014

Exhibit 24.34

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin**, do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ronald Rubin

Ronald Rubin

DATE: February 3, 2014

Exhibit 24.35

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin

Ann C. Berzin

DATE: February 7, 2014

Exhibit 24.36

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.37

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael E. Cryor

Michael E. Cryor

DATE: February 4, 2014

Exhibit 24.38

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James R. Curtiss

James R. Curtiss

DATE: February 4, 2014

Exhibit 24.39

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Kenneth W. DeFontes, Jr.**, do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Kenneth W. DeFontes, Jr.

Kenneth W. DeFontes, Jr.

DATE: February 3, 2014

Exhibit 24.40

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Joseph Haskins, Jr.

Joseph Haskins, Jr.

DATE: February 3, 2014

Exhibit 24.41

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Carla D. Hayden**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Carla D. Hayden

Carla D. Hayden

DATE: February 6, 2014

Exhibit 24.42

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien**, do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien

Denis P. O'Brien

DATE: February 4, 2014

Exhibit 31-1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
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: February 13, 2014

/s/ CHRISTOPHER M. CRANE

President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31-2

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
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: February 13, 2014

/s/ JONATHAN W. THAYER

Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 31-3

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
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: February 13, 2014

/s/ KENNETH W. CORNEW

President
(Principal Executive Officer)

Exhibit 31-4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
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: February 13, 2014

/s/ BRYAN P. WRIGHT

Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 31-5

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison 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: February 13, 2014

/s/ ANNE R. PRAMAGGIORE

President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31-6

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison 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: February 13, 2014

/s/ JOSEPH R. TRPIK, JR.

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy 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: February 13, 2014

/s/ CRAIG L. ADAMS

Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 31-8

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy 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: February 13, 2014

/s/ PHILLIP S. BARNETT

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 31-9

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. DeFontes Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and 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: February 13, 2014

/s/ KENNETH W. DEFONTES JR.

Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 31-10

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Carim V. Khouzami, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and 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: February 13, 2014

/s/ CARIM V. KHOUZAMI

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 13, 2014

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane
President and Chief Executive Officer

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 13, 2014

/s/ JONATHAN W. THAYER

Jonathan W. Thayer
Executive Vice President and Chief Financial Officer

Exhibit 32-3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 13, 2014

/s/ KENNETH W. CORNEW

Kenneth W. Cornew
President

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 13, 2014

/s/ BRYAN P. WRIGHT

Bryan P. Wright
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 13, 2014

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore
President and Chief Executive Officer

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 13, 2014

/s/ JOSEPH R. TRPIK, JR.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32-7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 13, 2014

/s/ CRAIG L. ADAMS

Craig L. Adams
Chief Executive Officer and President

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 13, 2014

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 13, 2014

/s/ KENNETH W. DEFONTES JR.

Kenneth W. DeFontes Jr.
Chief Executive Officer and President

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 13, 2014

/s/ CARIM V. KHOUZAMI

Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer

EXHIBIT 2

EXHIBIT 2

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

Commission File Number	Exact Name of Registrant as Specified in its Charter, State or Other Jurisdiction of Incorporation, Address of Principal Executive Offices, Zip Code and Telephone Number (Including Area Code)	I.R.S. Employer Identification Number
001-31403	**PEPCO HOLDINGS, INC.** (Pepco Holdings or PHI), a Delaware corporation 701 Ninth Street, N.W. Washington, D.C. 20068 Telephone: (202)872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** (Pepco), a District of Columbia and Virginia corporation 701 Ninth Street, N.W. Washington, D.C. 20068 Telephone: (202)872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** (DPL), a Delaware and Virginia corporation 500 North Wakefield Drive, 2nd Floor Newark, DE 19702 Telephone: (202)872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** (ACE), a New Jersey corporation 500 North Wakefield Drive, 2nd Floor Newark, DE 19702 Telephone: (202)872-2000	21-0398280

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

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Pepco Holdings	**Common Stock, $.01 par value**	**New York Stock Exchange**

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

Registrant	Title of Each Class
Pepco	**Common Stock, $.01 par value**
DPL	**Common Stock, $2.25 par value**
ACE	**Common Stock, $3.00 par value**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

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

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K (applicable to Pepco Holdings only). ☐

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 I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

Registrant	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Non-Affiliates of the Registrant at June 28, 2013	Number of Shares of Common Stock of the Registrant Outstanding at February 14, 2014
Pepco Holdings	$ 5,010.3 million (a)	250,517,109 ($.01 par value)
Pepco	None (b)	100 ($.01 par value)
DPL	None (c)	1,000 ($2.25 par value)
ACE	None (c)	8,546,017 ($3.00 par value)

(a) Solely for purposes of calculating this aggregate market value, PHI has defined its affiliates to include (i) those persons who were, as of June 28, 2013, its executive officers, directors and beneficial owners of more than 10% of its common stock, and (ii) such other persons who were deemed, as of June 28, 2013, to be controlled by, or under common control with, PHI or any of the persons described in clause (i) above.
(b) All voting and non-voting common equity is owned by Pepco Holdings.
(c) All voting and non-voting common equity is owned by Conectiv, LLC, a wholly owned subsidiary of Pepco Holdings.

THIS COMBINED FORM 10-K 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.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Pepco Holdings, Inc. definitive proxy statement for the 2014 Annual Meeting of Stockholders to be filed with the Securities and Exchange Commission within 120 days after December 31, 2013 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following is a glossary of terms, abbreviations and acronyms that are used in the Reporting Companies' SEC reports. The terms, abbreviations and acronyms used have the meanings set forth below, unless the context requires otherwise.

Term	Definition
2012 LTIP	Pepco Holdings, Inc. 2012 Long-Term Incentive Plan
ACE	Atlantic City Electric Company
ACE Funding	Atlantic City Electric Transition Funding LLC
AFUDC	Allowance for funds used during construction
AOCL	Accumulated Other Comprehensive Loss
AMI	Advanced metering infrastructure, a system that collects, measures and analyzes energy usage data from advanced digital electric and gas meters known as smart meters
ASC	Accounting Standards Codification
BGE	Baltimore Gas and Electric Company
BGS	Basic Generation Service (the supply of electricity by ACE to retail customers in New Jersey who have not elected to purchase electricity from a competitive supplier)
Bondable Transition Property	Principal and interest payments on the Transition Bonds and related taxes, expenses and fees
BSA	Bill Stabilization Adjustment
Budget Support Act	The Fiscal Year 2012 Budget Support Act of 2011, approved by the Council of the District of Columbia on June 14, 2011
CAA	Federal Clean Air Act
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
CTA	Consolidated tax adjustment
CWIP	Construction work in progress
DC Undergrounding Task Force	The District of Columbia Mayor's Power Line Undergrounding Task Force
DCPSC	District of Columbia Public Service Commission
DDOE	District of Columbia Department of the Environment
Default Electricity Supply	The supply of electricity by PHI's electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
DPL	Delmarva Power & Light Company
DEDA	Delaware Economic Development Authority
DEMEC	Delaware Municipal Electric Corporation, Inc.
DOE	U.S. Department of Energy
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
EBITDA	Earnings before interest, taxes, depreciation, and amortization
EDC	Electricity Distribution Company
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission

Term	Definition
FLRP	Forward Looking Rate Plan
FPA	Federal Power Act
GAAP	Accounting principles generally accepted in the United States of America
GCR	Gas Cost Rate
GenOn	GenOn MD Ash Management, LLC
GWh	Gigawatt hour
HPS	Hourly Priced Service
IMU	Interface management unit
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association Master Agreement
ISRA	Industrial Site Recovery Act
LIBOR	London Interbank Offered Rate
LTIP	Pepco Holdings, Inc. Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
Mcf	Thousand Cubic Feet
MDC	MDC Industries, Inc.
Medicare Act	Medicare Prescription Drug Improvement and Modernization Act of 2003
Medicare Part D	A prescription drug benefit under the Medicare Act
MFVRD	Modified fixed variable rate design
MMBtu	One Million British Thermal Units
MPSC	Maryland Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NERC	North American Electric Reliability Corporation
New Jersey Societal Benefit Charge	A surcharge related to the New Jersey Societal Benefit Program
New Jersey Societal Benefit Program	A New Jersey public interest program for low income customers
NJ SOCA Law	The New Jersey law under which the SOCAs were established
NJBPU	New Jersey Board of Public Utilities
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NUGs	Non-utility generators
NYMEX	New York Mercantile Exchange
OPC	Office of People's Counsel
OPEB	Other postretirement benefit
PCI	Potomac Capital Investment Corporation and its subsidiaries
Pepco	Potomac Electric Power Company
Pepco Energy Services	Pepco Energy Services, Inc. and its subsidiaries
Pepco Holdings or PHI	Pepco Holdings, Inc.
PHI OPEB Plan	The Pepco Holdings, Inc. Welfare Plan for Retirees
PJM	PJM Interconnection, LLC
PJM RTO	PJM regional transmission organization
Power Delivery	The transmission, distribution and default supply of electricity and, to a lesser extent, the distribution and supply of natural gas, conducted through Pepco, DPL and ACE, PHI's regulated public utility subsidiaries
PPA	Power purchase agreement
PRP	Potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005

Term	Definition
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
Regulatory Asset Recovery Charge	Costs associated with deferred, NJBPU-approved expenses incurred as part of ACE's obligation to serve the public
Reporting Company	PHI, Pepco, DPL or ACE
Revenue Decoupling Adjustment	An adjustment equal to the amount by which revenue from distribution sales differs from the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer
RFC	Reliability*First* Corporation
RI/FS	Remedial investigation and feasibility study
ROE	Return on equity
RPS	Renewable Energy Portfolio Standards
Sarbanes-Oxley Act	Sarbanes-Oxley Act of 2002
SEC	Securities and Exchange Commission
SOCA	Standard Offer Capacity Agreement required to be entered into by ACE pursuant to the NJ SOCA Law
SOS	Standard Offer Service, how Default Electricity Supply is referred to in Delaware, the District of Columbia and Maryland
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
SRECs	Solar renewable energy credits
T&D	Transmission and distribution
TEFA	Transitional Energy Facility Assessment, a New Jersey tax surcharge providing a gradual transition from the previous franchise and gross receipts tax eliminated in 1997, to its new total liability under the corporation business tax and the sales-and-use tax (this surcharge was eliminated in 2013)
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
USCG	U.S. Coast Guard
VRDBs	Variable Rate Demand Bonds
WACC	Weighted average cost of capital

FORWARD-LOOKING STATEMENTS

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

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

- Changes in governmental policies and regulatory actions affecting the energy industry or one or more of the Reporting Companies specifically, including allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of transmission and distribution facilities and the recovery of purchased power expenses;
- The outcome of pending and future rate cases and other regulatory proceedings, including (i) challenges to the base return on equity (ROE) and the application of the formula rate process previously established by the Federal Energy Regulatory Commission (FERC) for transmission services provided by Pepco, DPL and ACE; (ii) challenges to DPL's 2011, 2012 and 2013 annual FERC formula rate updates; and (iii) other possible disallowances of recovery of costs and expenses or delays in the recovery of such costs;
- The resolution of outstanding tax matters with the Internal Revenue Service (IRS), and the funding of any additional taxes, interest or penalties that may be due;
- The expenditures necessary to comply with regulatory requirements, including regulatory orders, and to implement reliability enhancement, emergency response and customer service improvement programs;
- Possible fines, penalties or other sanctions assessed by regulatory authorities against a Reporting Company or its subsidiaries;
- The impact of adverse publicity and media exposure which could render one or more Reporting Companies or their subsidiaries vulnerable to negative customer perception and could lead to increased regulatory oversight or other sanctions;
- Weather conditions affecting usage and emergency restoration costs;
- Population growth rates and changes in demographic patterns;

- Changes in customer energy demand due to, among other things, conservation measures and the use of renewable energy and other energy-efficient products, as well as the impact of net metering and other issues associated with the deployment of distributed generation and other new technologies;
- General economic conditions, including the impact on energy use caused by an economic downturn or recession, or by changes in the level of commercial activity in a particular region or service territory, or affecting a particular business or industry located therein;
- Changes in and compliance with environmental and safety laws and policies;
- Changes in tax rates or policies;
- Changes in rates of inflation;
- Changes in accounting standards or practices;
- Unanticipated changes in operating expenses and capital expenditures;
- Rules and regulations imposed by, and decisions of, federal and/or state regulatory commissions, PJM Interconnection, LLC (PJM), the North American Electric Reliability Corporation (NERC) and other applicable electric reliability organizations;
- Legal and administrative proceedings (whether civil or criminal) and settlements that affect a Reporting Company's or its subsidiaries' business and profitability;
- Pace of entry into new markets;
- Interest rate fluctuations and the impact of credit and capital market conditions on the ability to obtain funding on favorable terms; and
- Effects of geopolitical and other events, including the threat of terrorism or cyber attacks.

These forward-looking statements are also qualified by, and should be read together with, the risk factors included in Part I, Item 1A. "Risk Factors" and other statements in this Annual Report on Form 10-K, and investors should refer to such risk factors and other statements in evaluating the forward-looking statements contained in this Annual Report on Form 10-K.

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

Part I

Item 1. BUSINESS

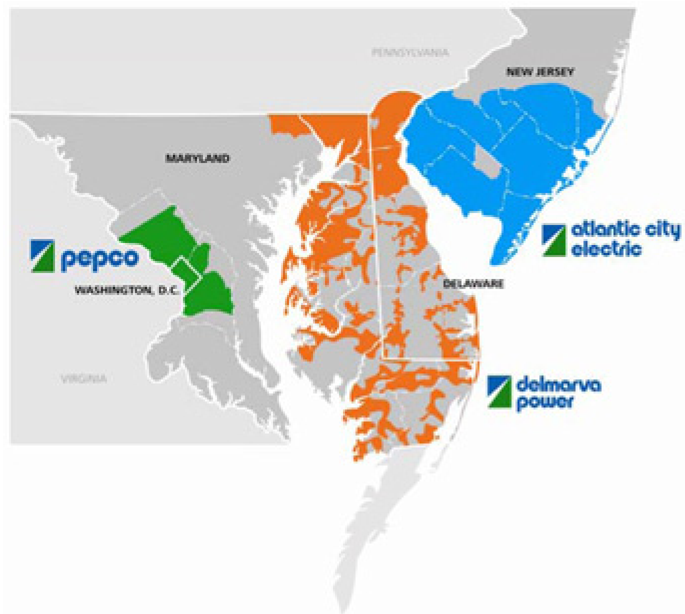
Overview

Pepco Holdings, Inc. (Pepco Holdings or PHI) is a holding company that was incorporated in Delaware in 2001. Through its regulated public utility subsidiaries, PHI is engaged primarily in the transmission, distribution and default supply of electricity, and, to a lesser extent, the distribution and supply of natural gas. The principal executive offices of PHI are located at 701 Ninth Street, N.W., Washington, D.C. 20068.

PHI's public utility subsidiaries are:

Name of Utility	State and Year of Incorporation	Business	Service Territories	Address of Principal Executive Offices
Potomac Electric Power Company (Pepco)	District of Columbia (1896) Virginia (1949)	Transmission, distribution and default supply of electricity	District of Columbia Major portions of Montgomery and Prince George's Counties, Maryland	701 Ninth Street, N.W., Washington, D.C. 20068
Delmarva Power & Light Company (DPL)	Delaware (1909) Virginia (1979)	Transmission, distribution and default supply of electricity Distribution and supply of natural gas	Portions of Delaware and Maryland (electricity) Portions of New Castle County, Delaware (natural gas)	500 North Wakefield Drive, Newark, Delaware 19702
Atlantic City Electric Company (ACE)	New Jersey (1924)	Transmission, distribution and default supply of electricity	Portions of Southern New Jersey	500 North Wakefield Drive, Newark, Delaware 19702

The service territories of each of Pepco Holdings' utilities are depicted in the map below:



PHI's three utility subsidiaries comprise a single operating segment for accounting purposes, which is referred to herein as "Power Delivery."

In addition to its regulated utility operations, Pepco Holdings, through Pepco Energy Services, Inc. and its subsidiaries (collectively, Pepco Energy Services), is engaged in the following activities:

- providing energy savings performance contracting services principally to federal, state and local government customers;
- designing, constructing and operating combined heat and power, and thermal energy plants; and
- providing high voltage underground transmission construction and maintenance services and low voltage electric construction and maintenance services and streetlight construction services.

The operations of Pepco Energy Services collectively comprise a separate, second operating segment for accounting purposes. During 2013, Pepco Energy Services completed the wind-down of its retail electricity and natural gas supply businesses, and, as a result, these businesses are being accounted for as discontinued operations, as described below under "Discontinued Operations."

Through its wholly owned subsidiary, Potomac Capital Investment Corporation (PCI), PHI previously held a portfolio of cross-border energy lease investments. During 2013, Pepco Holdings completed the termination of its interests in its cross-border energy lease investments, and as a result, these investments are being accounted for as discontinued operations, as described below under "Discontinued Operations."

The following table shows PHI's consolidated operating revenue and net income from continuing operations derived from the Power Delivery and Pepco Energy Services segments over the three preceding fiscal years.

	2013	2012	2011
		(millions of dollars)	
Operating Revenue			
Power Delivery	$4,472	$4,378	$4,650
Pepco Energy Services	203	256	330
Net Income (Loss) from Continuing Operations			
Power Delivery	$ 289	$ 235	$ 210
Pepco Energy Services	3	(8)	22

For additional financial information with respect to PHI's segments, see Note (5), "Segment Information," to the consolidated financial statements of PHI.

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

Business Strategy

PHI's business objective is to be a top-performing, regulated power delivery company that delivers safe and reliable electric and natural gas service to its customers and through its regulatory proceedings, earns a just and reasonable rate of return on, and receives timely recovery of, its utility investments.

In seeking to achieve this objective, Pepco Holdings' business strategy is guided by its core values of safety, integrity and diversity and its mission of environmental stewardship, and is focused on the following initiatives:

- investing in its utilities' transmission and distribution infrastructure;
- building a smarter grid and implementing other technological enhancements designed to:
  - automate power delivery system functions and improve the reliability of the power distribution system;
  - enable its utilities to restore power more quickly and efficiently;
  - offer customers detailed information about, and options to help customers better manage, their energy usage; and
  - enhance the customer experience and PHI's communications with customers; and
- through Pepco Energy Services, providing comprehensive energy management solutions and developing, installing and operating renewable energy solutions.

In furtherance of its business strategy, PHI may from time to time enter into various transactions involving its businesses. These transactions may include joint ventures, the disposition of existing businesses or the acquisitions of new businesses. PHI also may from time to time refine components of its business strategy as it deems necessary or appropriate in response to business factors and other conditions, including regulatory requirements.

Overview of the Power Delivery Business

Distribution and Default Supply of Electricity

Each of PHI's utility subsidiaries owns and operates a network of wires, substations and other equipment that are classified as transmission facilities, distribution facilities or common facilities (which are used for both transmission and distribution). Transmission facilities carry wholesale electricity into, out of and across the utilities' service territories. Distribution facilities carry electricity from the transmission facilities to the customers located in the utilities' service territories.

Each utility subsidiary is responsible for the distribution of electricity to customers within its service territory or territories and for which it is paid tariff rates established by the applicable public service commissions. While the transmission and distribution of electricity is regulated, the law of each of these service territories allows for competition in the supply of electricity, which enables distribution customers to contract to purchase their electricity from a supplier approved by the applicable public service commission. PHI's utility subsidiaries supply electricity at regulated rates to customers who do not elect to purchase their electricity from a competitive supplier. These "default" supply services are referred to generally in this Form 10-K as Default Electricity Supply. The regulatory term for Default Electricity Supply is Standard Offer Service (SOS) in Delaware, the District of Columbia and Maryland, and Basic Generation Service (BGS) in New Jersey. The results of operations of PHI's utility subsidiaries are only minimally impacted when customers choose to obtain their electricity through competitive suppliers because the utilities earn their approved rates of return by providing distribution service, and not by supplying the electricity.

Transmission of Electricity and Relationship With PJM

Each of PHI's utility subsidiaries provides transmission services within the jurisdictions that encompass its electricity distribution service territory. In the aggregate, PHI owns approximately 4,600 miles of interconnected transmission lines with voltages ranging from 115 kilovolts (kV) to 500 kV. Under the Open Access Transmission Tariff adopted by the FERC, each owner of transmission services is required to provide transmission customers with non-discriminatory access to its transmission facilities at tariff rates approved by FERC.

The transmission facilities owned by Pepco, DPL and ACE are interconnected with the transmission facilities of contiguous utilities and are part of an interstate power transmission grid over which electricity is transmitted throughout a region encompassing the mid-Atlantic portion of the United States and parts of the Midwest. PJM is the FERC-approved independent operator of this transmission grid and manages the wholesale electricity market within its region. Pepco, DPL and ACE each are members of the PJM Regional Transmission Organization (PJM RTO), the regional transmission organization designated by FERC to coordinate the movement of wholesale electricity in PJM's region.

In accordance with FERC-approved rules, Pepco, DPL, ACE and the other transmission-owning utilities in the PJM region make their transmission facilities available to PJM, and PJM directs and controls the operation of these transmission facilities. Each transmission owner is compensated at transmission rates approved by FERC for the use of its transmission facilities. PJM provides billing and settlement services, collects transmission service revenue from transmission service customers and distributes the revenue to the transmission owners.

PJM also directs the regional transmission planning process within its region. The Board of Managers of PJM reviews and approves all transmission expansion plans within the PJM region, including the construction of new transmission facilities by PJM members. Changes in the current policies for building new transmission lines ordered by FERC and implemented by PJM could result in additional competition to build transmission lines in the PJM region, including in the service territories of PHI's utility subsidiaries, and could allow PHI's utility subsidiaries the opportunity to construct transmission facilities in other service territories.

For a discussion of the regulation of transmission rates, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Regulatory and Other Matters – Rate Proceedings – Transmission" and for a discussion of recently completed and pending FERC transmission rate proceedings, see Note (7), "Regulatory Matters – Rate Proceedings – Federal Energy Regulatory Commission," to the consolidated financial statements of PHI.

Distribution and Supply of Natural Gas

DPL owns pipelines and other equipment for the distribution and supply of natural gas. DPL uses its natural gas distribution facilities to deliver natural gas to retail customers in its service territory and provides transportation-only services to customers that purchase natural gas from another supplier. Intrastate transportation customers pay DPL distribution service rates approved by the Delaware Public Service Commission (DPSC). Rates for the interstate transportation and sale of wholesale natural gas are regulated by FERC. DPL purchases natural gas supplies for resale to its retail service customers from marketers and producers through a combination of long-term agreements and next-day distribution arrangements.

PHI's Utility Subsidiaries

Potomac Electric Power Company

Pepco's electric distribution service territory consists of the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland. The service territory covers approximately 640 square miles and, as of December 31, 2013, had a population of approximately 2.2 million. This region is economically diverse and includes key industries that contribute to the regional economic base:

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

The following table shows the number of Pepco distribution customers in each of its service territories as of the end of each of the preceding three years.

	2013	2012	2011
		(in thousands)	
District of Columbia	264	260	257
Maryland	537	533	531
Total	801	793	788

Pepco distributed a total of 25,801,000, 26,006,000 and 26,895,000 megawatt (MW) hours (MWh) of electricity in 2013, 2012 and 2011, respectively. The following table shows the allocation by percentage among customer types of the total MWh of electricity delivered by Pepco in each of its service territories during each of the preceding three fiscal years:

	2013	2012	2011
District of Columbia:			
Residential	13%	13%	13%
Commercial, industrial and other	30%	30%	30%
Total	43%	43%	43%
Maryland:			
Residential	17%	17%	17%
Commercial, industrial and other	40%	40%	40%
Total	57%	57%	57%

Pepco has been designated as the default electricity supplier in its District of Columbia and Maryland service territories by the District of Columbia Public Service Commission (DCPSC) and the Maryland Public Service Commission (MPSC), respectively. Pepco purchases the electricity required to satisfy its SOS obligations from wholesale suppliers primarily under contracts entered into in accordance with competitive bid procedures approved and supervised by each of the DCPSC and the MPSC. For commercial customers in the District of Columbia and large commercial customers in Maryland that do not purchase their electricity from a competitive supplier, Pepco is obligated to provide Hourly Priced Service (HPS), a form of SOS service for which Pepco purchases the electricity in the next-day and other short-term PJM RTO markets.

Under orders issued by the DCPSC, Pepco is obligated to provide SOS to residential and small, medium-sized and large commercial customers in the District of Columbia indefinitely. Under orders issued by the MPSC, Pepco is obligated to provide SOS to residential and small commercial customers and to medium-sized commercial customers in Maryland through November 2014. As contracts expire, they are rebid annually by Pepco through the MPSC-approved request for proposal process. Pepco is paid tariff rates for the transmission and distribution of electricity over its transmission and distribution facilities to all electricity customers in its service territory, whether the customer receives SOS or HPS, or purchases electricity from a competitive supplier, and is entitled to recover from its SOS and HPS customers the costs of acquiring the electricity, plus an administrative charge that is intended to allow it to recover its administrative costs, plus a modest margin, which varies depending on the customer class.

The following table shows for Pepco customers in the District of Columbia and Maryland the percentage of distribution sales (measured by MWh) over the past three fiscal years to SOS customers.

	2013	2012	2011
District of Columbia	25%	25%	27%
Maryland	41%	40%	43%

In the District of Columbia, under various acts of Congress, pursuant to Pepco's corporate charter, and subject to the supervision of the DCPSC, Pepco has the non-exclusive authority to install and maintain overhead and underground transmission and distribution lines and other related facilities for the furnishing of electricity. Pepco's right to occupy public space for utility purposes is by permit from the District of Columbia and the federal government. Pepco is the only public utility that distributes electricity for sale to the public in the District of Columbia.

In Maryland, Pepco operates pursuant to state-wide franchises granted by Maryland's General Assembly that are unlimited in duration. These franchises were granted to Pepco or to predecessor companies acquired by Pepco, and confer, among other things, the ability to construct electric transmission and distribution lines. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MPSC. The service territories for Pepco, as well as for other electric utilities in the state, were precisely delineated in 1966 by the MPSC and have been modified in minor ways over the years.

Delmarva Power & Light Company

DPL is engaged in the transmission, distribution and default supply of electricity in portions of Delaware and Maryland. In northern Delaware, DPL also supplies and delivers natural gas to retail customers and provides transportation-only services to retail customers that purchase natural gas from another supplier.

In Maryland, DPL operates pursuant to state-wide franchises that are substantially similar in nature to those described above with respect to Pepco's Maryland operations. DPL's exclusive and continuing authority to distribute electricity and natural gas in its non-municipal service territories in Delaware is derived from legislation, through which the DPSC has established exclusive service territories. With respect to municipalities that it serves, DPL provides service under various franchises granted to DPL and predecessor companies, which franchises are generally either unlimited as to time or renew automatically.

Distribution and Supply of Electricity

DPL's electric distribution service territory consists of the state of Delaware, and Caroline, Cecil, Dorchester, Harford, Kent, Queen Anne's, Somerset, Talbot, Wicomico and Worcester counties in Maryland. This territory covers approximately 5,000 square miles and, as of December 31, 2013, had a population of approximately 1.4 million. This region is economically diverse and includes the following key industries that contribute to the regional economic base:

- Commercial activities in the region include banking, government, insurance, shopping malls, casinos and tourism.
- Industrial activities in the region include chemical, pharmaceutical, steel manufacturing and oil refining.

The following table shows the number of DPL electricity distribution customers in each of its service territories as of the end of each of the preceding three fiscal years.

	2013	2012	2011
		(in thousands)	
Delaware	305	303	301
Maryland	201	200	200
Total	506	503	501

DPL distributed a total of 12,465,000, 12,641,000 and 12,688,000 MWh of electricity in 2013, 2012 and 2011, respectively. The following table shows the allocation by percentage among customer types of the total MWh of electricity delivered by DPL in each of its service territories during each of the preceding three fiscal years:

	2013	2012	2011
Delaware:			
Residential	27%	27%	27%
Commercial and industrial	39%	40%	39%
Total	66%	67%	66%
Maryland:			
Residential	14%	13%	14%
Commercial and industrial	20%	20%	20%
Total	34%	33%	34%

DPL has been designated as the default electricity supplier in its Delaware and Maryland service territories by the DPSC and the MPSC, respectively. DPL purchases the electricity required to satisfy its SOS obligations from wholesale suppliers primarily under contracts entered into in accordance with competitive bid procedures approved and supervised by each of the DPSC and the MPSC. DPL also has an obligation to provide HPS for its largest customers in Delaware and its large customers in Maryland. DPL acquires power to supply its HPS customers in the next-day and other short-term PJM RTO markets.

Under orders issued by the DPSC, DPL is obligated to provide SOS to residential, small commercial and industrial customers in Delaware through May 2017, and to medium, large and general service commercial customers in Delaware through May 2015. Under orders issued by the MPSC, DPL is obligated to provide SOS to residential and small commercial customers in Maryland until further action of the Maryland General Assembly, and to medium-sized commercial customers in Maryland through November 2014. As contracts expire, they are rebid annually by DPL through the MPSC approved request for proposal process. In Delaware and Maryland, DPL is paid tariff rates for the transmission and distribution of electricity over its transmission and distribution facilities to all electricity customers in its service territories, whether the customer receives SOS or HPS, or purchases electricity from a competitive supplier. In Delaware, DPL is also entitled to recover from its SOS and HPS customers the associated costs of acquiring the electricity (including transmission, capacity and ancillary services costs and costs to satisfy renewable energy requirements), plus an amount referred to as a Reasonable Allowance for Retail Margin. In Maryland, DPL is entitled to recover from its SOS and HPS customers the costs of acquiring the electricity, plus an administrative charge that is intended to allow it to recover its administrative costs, plus a modest margin, which varies depending on the customer class.

The following table shows for DPL customers in Delaware and Maryland the percentage of distribution sales (measured in MWh) over the past three fiscal years to SOS customers.

	2013	2012	2011
Delaware	44%	47%	51%
Maryland	51%	53%	58%

Distribution and Supply of Natural Gas

DPL provides regulated natural gas supply and distribution service to customers in a service territory consisting of a major portion of New Castle County in Delaware. This service territory covers approximately 275 square miles and, as of December 31, 2013, had a population of approximately 500,000.

Large volume commercial, institutional, and industrial natural gas customers may purchase natural gas from DPL. Alternatively, a customer receiving a “transportation-only” service from DPL will purchase natural gas from a competitive supplier and have the natural gas delivered through DPL’s distribution facilities. The following table provides certain information regarding DPL’s natural gas distribution business for each of the last three fiscal years.

	2013	2012	2011
	(in thousands, except percentages)		
Number of natural gas customers	126	125	124
Thousand cubic feet (Mcf) of natural gas delivered	19,796	16,815	18,754
Percentage of natural gas supplied and Delivered by DPL	64%	60%	64%

The following table shows on a percentage basis the allocation among customer types of the Mcf of natural gas delivered by DPL in Delaware in each of the preceding three fiscal years.

	2013	2012	2011
Residential	40%	38%	39%
Commercial and industrial	25%	22%	24%
Transportation and other	35%	40%	37%

Atlantic City Electric Company

Electricity Distribution and Supply

ACE's electric distribution service territory consists of Gloucester, Camden, Burlington, Ocean, Atlantic, Cape May, Cumberland and Salem counties in southern New Jersey. The service territory covers approximately 2,700 square miles and had, as of December 31, 2013, a population of approximately 1.1 million. This region is economically diverse and includes key industries that contribute to the regional economic base:

- Commercial activities in the region include professional services, government, shopping malls, casinos, and tourism.
- Industrial activities in the region include chemical, glass, food processing and oil refining.

The following table provides certain information regarding ACE's electric distribution business for each of the last three fiscal years.

	2013	2012	2011
		(in thousands)	
Number of electric distribution customers	545	545	547
MWh of electricity delivered	9,231	9,495	9,683

The following table shows the allocation by percentage among customer types of the total MWh of electricity delivered by ACE during each of the preceding three fiscal years.

	2013	2012	2011
Residential	46%	46%	46%
Commercial and industrial	54%	54%	54%

ACE has been designated as the default electricity supplier in its service territory by the New Jersey Board of Public Utilities (NJBPU). In New Jersey, each of the state's electric distribution companies, including ACE, jointly obtains the electricity to meet such companies' collective BGS obligations from competitive suppliers selected through auctions authorized by the NJBPU for the supply of New Jersey's total BGS requirements. Each winning bidder is required to supply its committed portion of the BGS customer load with full requirements service, consisting of power supply and transmission service. ACE provides two types of BGS:

- fixed price BGS, which is provided to smaller commercial and residential customers at seasonally-adjusted fixed prices (which as of December 31, 2013, had a peak load of approximately 1,429 MW and represented approximately 97% of ACE's total BGS load); and
- commercial and industrial energy price BGS, which is provided to large customers at hourly PJM RTO real-time market prices for a term of 12 months (which as of December 31, 2013, had a peak load of approximately 42 MW and represented approximately 3% of ACE's total BGS load).

ACE is paid tariff supply rates established by the NJBPU that compensate it for the cost of obtaining the BGS supply. These rates are set such that ACE does not make any profit or incur any loss with respect to the supply component of its BGS obligations. ACE is also paid tariff rates for the transmission and distribution of electricity over its transmission and distribution facilities to all electricity customers in its service territory, whether the customer receives BGS or purchases electricity from a competitive supplier.

For the year ended December 31, 2013, 48% of ACE's total distribution sales (measured in MWh) were to BGS customers, as compared to 51% and 56% in 2012 and 2011, respectively.

ACE operates under non-exclusive franchises that have been granted by the NJBPU and under certain non-exclusive consents from municipalities in which ACE provides service. While most of the municipal consents were granted in perpetuity, two of the municipal consents require renewal on a periodic basis in accordance with their terms, and are subject to the ultimate review and approval of the NJBPU. All of the franchises and consents are currently in full force and effect.

Atlantic City Electric Transition Funding LLC

In 2001, ACE established Atlantic City Electric Transition Funding LLC (ACE Funding) 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 were transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect a non-bypassable transition bond charge (Transition Bond Charge) from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on the Transition Bonds and related taxes, expenses and fees (Bondable Transition Property). The assets of ACE Funding, including the Bondable Transition Property, and the Transition Bond Charges (representing revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees) collected from ACE's customers, are not available to creditors of ACE. The holders of Transition Bonds have recourse only to the assets of ACE Funding.

Smart Grid Initiatives

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

- improving service reliability of the energy distribution system;
- automating specific distribution system functions;
- enabling its utilities to restore energy to customers more quickly and efficiently;
- facilitating more efficient use of energy to meet the challenges of rising energy costs and governmental energy reduction goals;
- permitting its utilities to obtain and communicate to their customers timely and accurate information regarding energy usage and outages; and
- enhancing communications with its customers and the overall customer experience.

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

The installation of smart meters in the service territories of each of PHI's utility subsidiaries is subject to approval by the applicable public service commissions. The regulatory and implementation status of Pepco Holdings' AMI smart meter activities as of December 31, 2013 was as follows:

Utility	Jurisdiction	Regulatory Status	Installation and Activation Status
Pepco	Maryland	Approved	Complete
	District of Columbia	Approved	Complete
DPL (Electric)	Delaware	Approved	Complete
	Maryland	Approved	Estimated Completion 3Q 2014
DPL (Natural Gas)	Delaware	Approved	Substantially Complete
ACE	New Jersey	Not approved	N/A

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

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

- Pepco was awarded $149 million for AMI, direct load control, distribution automation and communications infrastructure, of which $145 million has been received through December 31, 2013.
- ACE was awarded $19 million for direct load control, distribution automation and communications infrastructure, of which $17 million has been received through December 31, 2013.

For a discussion of the projected capital expenditures of each utility subsidiary associated with PHI's smart grid initiatives over the period 2014 through 2018, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Capital Requirements."

Utility Capital Expenditures

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

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

In addition, PHI's utility subsidiaries devote capital expenditures to increasing transmission and distribution system capacity, providing resiliency against major storm events, providing operating and system flexibility and installing and upgrading facilities for new and existing customers. For a discussion of PHI's consolidated capital expenditure plan for 2014 through 2018, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Capital Requirements – Capital Expenditures."

Maryland Grid Resiliency Task Force

In September 2012, a Grid Resiliency Task Force established through an executive order issued by the Governor of Maryland issued a report containing 11 recommendations on improving the resiliency and reliability of the electric distribution system in Maryland. In October 2012, the Governor of Maryland forwarded the report to the MPSC and urged the MPSC to implement quickly four of the Grid Resiliency Task Force's recommendations:

- strengthen existing reliability and storm restoration regulations;
- accelerate the investment necessary to meet the enhanced metrics;
- allow surcharge recovery for the accelerated investment; and
- implement clearly defined performance metrics into the traditional ratemaking scheme.

Components of Pepco's electric distribution base rate case filed with the MPSC in November 2012 and DPL's electric distribution base rate case filed with the MPSC in March 2013 were intended to address the Grid Resiliency Task Force recommendations. In July and August 2013, the MPSC issued orders in these base rate cases that only partially approved these components. See Note (7), "Regulatory Matters – Rate Proceedings – Maryland" to the consolidated financial statements of PHI for more information about these base rate cases.

District of Columbia Proposed Undergrounding Legislation

In August 2012, the Mayor of the District of Columbia issued an Executive Order establishing the Mayor's Power Line Undergrounding Task Force (the DC Undergrounding Task Force). In May 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan to underground 60 of the District of Columbia's most outage-prone power lines, which lines would be owned and maintained by Pepco. The legislation providing for implementation of the DC Undergrounding Task Force recommendations contemplates that:

- $500 million of the estimated cost would be funded by Pepco, with recovery of its investment to be made through surcharges to be billed to Pepco District of Columbia customers;
- $375 million of the estimated cost would be financed by the District of Columbia's issuance of securitized bonds, which bonds would be repaid through surcharges to be billed to Pepco District of Columbia customers (Pepco would not earn a return on or of the cost of the assets funded with the proceeds of these securitized bonds); and
- the remaining $125 million would be funded through the District of Columbia Department of Transportation's existing capital projects program.

This legislation was approved by the Council of the District of Columbia on February 4, 2014 and is awaiting the signature of the Mayor of the District of Columbia. Once signed by the Mayor and transmitted to Congress, the legislation will undergo a 30-day Congressional review period before becoming law, which is expected to be completed in the second quarter of 2014. The final step would be for the DCPSC to approve the underground project plan and issue financing orders to establish the customer surcharges contemplated by the undergrounding law. A decision by the DCPSC on such actions would likely occur during the fourth quarter of 2014.

NERC Reliability Standards

NERC has 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 and ACE. There are eight NERC regional oversight entities, including Reliability*First* Corporation (RFC), of which Pepco, DPL, ACE and Pepco Energy Services are members. These oversight entities are charged with the day-to-day implementation and enforcement of NERC's reliability standards, which impose certain operating, planning and cybersecurity requirements on the bulk power systems of each utility. RFC performs compliance audits on entities registered with NERC based on reliability standards and criteria established by NERC. NERC and RFC also conduct compliance investigations in response to a system disturbance, complaint, or possible violation of a reliability standard identified by other means. Each of PHI's utility subsidiaries are subject to routine audits and monitoring for compliance with applicable NERC reliability standards, including standards requested by FERC to increase the number of assets designated as "critical assets" (including cybersecurity assets) subject to NERC's cybersecurity standards. NERC is empowered to impose financial penalties, fines and other sanctions for non-compliance with certain rules and regulations.

Energy Efficiency Initiatives

Dynamic Pricing

Dynamic pricing provides customers with incentives to reward them for decreasing their energy use during peak energy demand periods, when energy demand and consequently, the cost of supplying electricity, are higher. PHI's dynamic pricing rate structures, implemented in tandem with PHI's smart grid, provide customers with billing credits when they reduce their power usage in response to their utility's request.

Dynamic pricing has been approved by the respective public service commissions and is in place for Pepco customers in Maryland and DPL customers in Delaware. As of December 31, 2013, approximately 625,000 Pepco customers in Maryland and 293,000 DPL customers in Delaware have received dynamic pricing program credits. Dynamic pricing has been approved in concept pending AMI deployment for DPL's Maryland SOS customers. Pepco's dynamic pricing proposal in the District of Columbia was rejected by the DCPSC on February 7, 2014. Pepco is considering its options in that jurisdiction with respect to dynamic pricing. Dynamic pricing has not been approved at this time by the NJBPU for ACE's customers in New Jersey.

Utility Energy Efficiency Programs

Each of Pepco, DPL and ACE has implemented the Energy Wise Rewards™ program, which allows participating customers to reduce energy usage and costs by authorizing the utility to cycle their air conditioner compressors off and on during high energy demand periods. Customers participating in this program are eligible to receive a credit on their bill. Pepco and DPL have also implemented a portfolio of energy efficiency programs designed to reduce energy consumption in Maryland, including appliance rebate and recycling, home energy check-ups, rebates on the purchase of energy efficiency equipment and services and discounts on energy efficient light bulbs and lighting fixtures. The MPSC has approved a customer surcharge through 2014 to recover Pepco's and DPL's costs associated with these energy efficiency programs.

Pepco Energy Services

Pepco Energy Services is engaged in the following:

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

The energy savings performance contracting business is highly competitive, and Pepco Energy Services competes with other energy services companies primarily with respect to contracts with federal, state and local governments and independent agencies. Many of these energy services companies are subsidiaries of larger building controls and equipment providers or utility holding companies. Competitive offerings include a wide range of electrical and thermal system upgrades, improved controls, and generation equipment such as combined heat and power units. Among the factors as to which companies in this business compete are the amount and duration of the guarantees provided in energy savings performance contracts and the quality and value of service provided to customers. In connection with many of Pepco Energy Services' energy savings performance contracts, Pepco Energy Services provides performance guarantees, including guarantees of a certain level of energy savings. This business is affected by new entrants into the market, the financial strength of customers, governmental directives regarding energy efficiency, energy prices, and general economic conditions. Pepco Energy Services' backlog of construction contracts in this business increased to $91 million at year-end 2013 from $82 million at year-end 2012. Pepco Energy Services estimates that it will complete $88 million of the construction contracts in its backlog in 2014 and $3 million in 2015.

Most of Pepco Energy Services' energy savings performance contracts with federal, state and local governments, as well as those with 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 which, 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.

Through its wholly owned subsidiary, W.A. Chester, L.L.C., Pepco Energy Services constructs and maintains underground transmission and distribution projects for electric utilities in North America. W.A. Chester is one of the two largest North American contractors that specializes in the installation and maintenance of pipe-type cable systems, a technology that W.A. Chester believes currently accounts for the majority of existing underground transmission circuit miles in North America. W.A. Chester's primary competitor in the pipe-type cable system market is UTEC Constructors Corporation, and there are several other contractors that do not specialize in this cable system but rather undertake installation projects on a more limited basis. W.A. Chester also competes in the market for the installation and maintenance of solid dielectric cable, which is a relatively newer technology compared to pipe-type cable systems. The solid dielectric cable installation and maintenance market is highly competitive and composed of numerous different competitors, and the barriers to entry in this market are relatively low. The principal factors for competition in both of these markets are price, experience, customer service and ability to handle a wide range of utility applications. W.A. Chester believes its competitive strengths in both of these markets are the breadth of its experience in working with both technologies in various utility applications (including new installations, modifications, upgrades and maintenance of existing systems), its in-depth knowledge of the U.S. and Canadian utility industries and utility customers' needs, and its ability to manage successfully all phases of these projects for the customer. W.A. Chester's backlog of construction contracts increased to $84 million at year-end 2013 from $38 million at year-end 2012. W.A. Chester estimates that it will complete $73 million of the construction contracts in its backlog in 2014 and $11 million in 2015.

Revenues associated with Pepco Energy Services' combined heat and power thermal generating plant and operations are concentrated with a few major customers in the Atlantic City hotel and casino industry. Pepco Energy Services has long-term contracts with these customers, and for the largest customer, the contracts expire in 2017. The Atlantic City hotel and casino industry has been experiencing a decrease in gaming revenues and overcapacity, as well as potential future competition from casinos that are being constructed in nearby markets. As a result, Pepco Energy Services is exposed to the risk that it may not be able to renew these contracts or that the contract counterparties may fail to perform their obligations thereunder.

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At December 31, 2013, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $190 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects in these businesses. These guarantees totaled $229 million at December 31, 2013.

During 2012, Pepco Energy Services deactivated its Buzzard Point oil-fired generation facility and its Benning Road oil-fired generation facility, and in 2013 began work to demolish the Benning Road facility. This demolition is expected to be completed by the end of 2014. At December 31, 2013, Pepco Energy Services owned five renewable energy generating facilities, with an aggregate generating capacity of 17,400 KW. See Part I, Item 2. "Properties – Generating Facilities" for more information about these facilities.

Discontinued Operations

Through its subsidiary Potomac Capital Investment Corporation, PHI maintained a portfolio of cross-border energy lease investments. During the third quarter of 2013, PHI completed the termination of its interests in its cross-border energy lease investments. These activities, which previously comprised substantially all of the operations of the Other Non-Regulated segment, are being accounted for as discontinued operations. The remaining operations of the Other Non-Regulated segment, which no longer meet the definition of a separate segment for financial reporting purposes, are being included in Corporate and Other. Substantially all of the information in the notes to the consolidated financial statements of PHI with respect to the cross-border energy lease investments has been consolidated in Note (19), "Discontinued Operations – Cross-Border Energy Lease Investments."

In 2013, Pepco Energy Services completed a previously announced wind-down of its retail electric and retail natural gas supply businesses. These operations are being accounted for as discontinued operations and are no longer a part of the Pepco Energy Services segment for financial reporting purposes. Substantially all of the information in the notes to the consolidated financial statements of PHI with respect to Pepco Energy Services' retail electric and retail natural gas supply businesses has been consolidated in Note (19), "Discontinued Operations – Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services."

Seasonality

Power Delivery

The operating results of Power Delivery historically have been directly related to the volume of electricity delivered to its customers, producing higher revenues and net income during periods when customers consumed higher amounts of electricity (usually during periods of extreme temperatures) and lower revenues and net income during periods when customers consumed lower amounts of electricity (usually during periods of mild temperatures). This has been due in part to the longstanding practice of tying the distribution charges paid by customers to kilowatt-hours of electricity used. Because most of the costs associated with the distribution of electricity do not vary with the volume of electricity delivered, this pricing mechanism also contributed to seasonal variations in net income.

As a result of the implementation of a bill stabilization adjustment (BSA) for retail customers of Pepco and DPL in Maryland and for customers of Pepco in the District of Columbia, distribution revenues from utility customers in these jurisdictions have been decoupled from the amount of electricity delivered. Under the BSA, utility customers pay an approved distribution charge for their electric service which does not vary by electricity usage. This change has had the effect of aligning annual distribution revenues more closely with annual distribution costs. In addition, the change has had the effect of eliminating changes in customer electricity usage, whether due to weather conditions or for any other reason, as a factor having an impact on annual distribution revenue and net income in those jurisdictions. The BSA also eliminates what otherwise might be a disincentive for the utility to aggressively develop and promote efficiency programs. A comparable revenue decoupling mechanism proposed for DPL electricity and natural gas customers in Delaware is under consideration by the DPSC although there was little activity in this matter in 2013. Distribution revenues are not decoupled for the distribution of electricity by ACE in New Jersey, and thus are subject to variability due to changes in customer consumption.

In contrast to electricity distribution costs, the cost of the electricity supplied, which is the largest component of a customer's bill, does vary directly in relation to the volume of electricity used by a customer. Accordingly, whether or not a BSA is in effect for the jurisdiction, the revenues of Pepco, DPL and ACE from the supply of electricity and natural gas vary based on consumption and on this basis are seasonal. Because the revenues received by each of the utility subsidiaries for the default supply of electricity and natural gas closely approximate the supply costs, the impact on net income is immaterial, and therefore is not seasonal.

Pepco Energy Services

The energy services business of Pepco Energy Services is not seasonal, except with respect to its thermal operations. The thermal operations of Pepco Energy Services provide steam and chilled water to customers year-round. Steam usage peaks during months with colder temperatures and chilled water usage peaks during months with warmer temperatures. The rates charged customers adjust quarterly for the cost of natural gas used to produce steam and electricity used to produce chilled water. Pepco Energy Services' revenues and gross profit from its thermal operations will fluctuate based on the volumes of steam and chilled water delivered to customers.

Regulation

The operations of PHI's utility subsidiaries, including the rates and tariffs they are permitted to charge customers for the transmission and distribution of electricity, and, in the case of DPL, the distribution and transportation of natural gas, are subject to regulation by governmental agencies in the jurisdictions in which the subsidiaries provide utility service as described above in " – PHI's Utility Subsidiaries." Rates and tariffs are established by these regulatory commissions. PHI's utility subsidiaries have filed or plan to file rate cases in each of its jurisdictions as further described in Note (7), "Regulatory Matters – Rate Proceedings," to the consolidated financial statements of PHI.

In addition to the other regulatory matters described elsewhere in this section and in Note (7), "Regulatory Matters," to the consolidated financial statements of PHI, provided below are summary descriptions of certain regulatory matters involving PHI's utility subsidiaries.

Mitigation of Regulatory Lag

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

In an effort to minimize the effects of regulatory lag, PHI's utility subsidiaries are:

- filing electric distribution base rate cases every nine to twelve months in each of their jurisdictions,
- pursuing alternative ratemaking mechanisms,
- evaluating potential reductions in planned capital expenditures, and
- continuing outreach to the regulatory community and other stakeholders, to discuss the changing regulatory model economics that are causing regulatory lag.

Alternative mechanisms that may reduce regulatory lag include adjusting historic test periods in distribution base rate cases to recognize plant additions which are already being used to provide service to customers when new rates go into effect, grid resiliency charges to allow contemporaneous cost recovery of costs for infrastructure related to system reliability, and multi-year rate plans.

Each of PHI's utility subsidiaries will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag and have an opportunity to earn its authorized ROE. There can be no assurance that any attempts by PHI's utility subsidiaries to mitigate regulatory lag will be approved or, that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag.

FERC MAPP Abandonment Cost Filing

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

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

In December 2013, PHI submitted a settlement agreement to FERC with respect to this matter. Under the terms of the proposed settlement agreement, Pepco and DPL would recover their abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. The terms of this settlement, if approved, would not be subject to the pending formula rate or transmission ROE challenges at FERC or modification through any other FERC proceeding. PHI cannot predict the timing or results of a final FERC decision in this proceeding.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland. In April 2012, the MPSC issued an order requiring Pepco, DPL and Baltimore Gas and Electric Company (BGE) (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder for the construction of a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The April 2012 order specified that each of the Contract EDCs will recover its costs associated with the contract through surcharges on its SOS customers.

In April 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC order. In May 2012, the Contract EDCs and other parties also filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC order, and these notices of appeal were consolidated in a single appeal in the Circuit Court for Baltimore City.

In September and October 2013, the U.S. District Court issued a final decision and order, respectively, holding that the MPSC order violated the Supremacy Clause of the U.S. Constitution and finding that the contracts that had been entered into in June 2013 between each of the Contract EDCs and the winning bidder (as mandated by an April 2013 order of the MPSC) were illegal and unenforceable. In November 2013, the MPSC and the winning bidder appealed the U.S. District Court's decision and order to the U.S. Circuit Court of Appeals for the Fourth Circuit. This appeal presently remains pending.

In October 2013, the Maryland Circuit Court for Baltimore County issued a ruling upholding the MPSC's orders requiring the Contract EDCs to enter into the contracts. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's ruling to the Maryland Court of Special Appeals. This appeal presently remains pending.

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

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three Standard Offer Capacity Agreements (SOCAs) by order of the NJBPU, each with a different generation company, as more fully described in Note (13), "Derivative Instruments and Hedging Activities," to the consolidated financial statements of PHI. One of the three SOCAs was terminated effective July 1, 2013 because of an event of default of the generation company that was a party to the SOCA.

ACE and the other EDCs in New Jersey entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). This dispute was pending before the NJBPU; however, in April 2013, it was consolidated with an appeal filed in June 2011 by the EDCs in the Superior Court of New Jersey Appellate Division.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In October 2013, the U.S. District Court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause, and is therefore null and void, and an order deciding that the remaining SOCAs are void, invalid and unenforceable. The U.S. District Court decision's has been appealed to the U.S. Third Circuit Court of Appeals, and this appeal presently remains pending. In light of the U.S. District Court's decision, the New Jersey Appellate Division dismissed the EDCs' appeal without prejudice, subject to the EDCs' rights to revive their appeal if the U.S. District Court's decision is reversed.

Delaware Renewable Energy Portfolio Standards

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. In July 2011, the Governor of the State of Delaware signed legislation that expanded DPL's RPS obligations beginning in 2012. Before this legislation, DPL was required to obtain RECs for energy delivered only to SOS customers in Delaware; the legislation expands that requirement to energy delivered to all of DPL's distribution customers in Delaware. DPL's costs associated with obtaining RECs to fulfill its RPS obligations are recoverable from its distribution customers by law.

The legislation also establishes that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels is an eligible resource for RECs under the Renewable Portfolio Standards Act. The legislation requires that the DPSC adopt a tariff under which DPL would be an agent that collects payments from its customers and disburses the amounts collected to a qualified fuel cell provider that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility. The legislation also provides for a reduction in DPL's REC and solar REC requirements based upon the actual energy output of the 30-megawatt generation facility. In October 2011, the DPSC approved the tariff submitted by DPL in response to the legislation. For more information on the tariff, see Note (16), "Variable Interest Entities – DPL Renewable Energy Transactions," to the consolidated financial statements of PHI.

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, greenhouse gas emissions, and limitations on land use. In addition, federal and state statutes authorize governmental agencies to compel responsible parties to clean up certain abandoned or unremediated hazardous waste sites. PHI's subsidiaries may incur costs to clean up currently or formerly owned facilities or sites found to be contaminated, as well as other facilities or sites that may have been contaminated due to past disposal practices. PHI's subsidiaries may also be responsible for ongoing environmental remediation costs associated with facilities or operations that have been sold to third parties as further described in Note (15), "Commitments and Contingencies – Environmental Matters – Conectiv Energy Wholesale Power Generation Sites," to the consolidated financial statements of PHI.

PHI's subsidiaries' currently projected capital expenditures for the replacement of existing or installation of new environmental control facilities that are necessary for compliance with environmental laws, rules or agency orders are approximately $7.5 million in 2014, $7.8 million in 2015, and $2.4 million in each of 2016, 2017 and 2018. The projections for these capital expenditures could change depending on the outcome of the matters addressed below or as a result of the imposition of additional environmental requirements or new or different interpretations of existing environmental laws, rules and agency orders. In view of the sale of the Conectiv Energy wholesale power generation business in 2010 and the deactivation in 2012 of two generating facilities located in the District of Columbia owned by Pepco Energy Services, PHI is no longer significantly affected by air quality and other environmental regulations applicable to electricity generating facilities.

Air Quality Regulation

The generating facilities owned by Pepco Energy Services were subject to federal, state and local laws and regulations, including the Federal Clean Air Act (CAA), which limit emissions of air pollutants, require permits for operation of facilities and impose recordkeeping and reporting requirements. Following the June 2012 deactivation of Pepco Energy Services' Buzzard Point and Benning Road oil-fired generating facilities, both of which were considered major sources under the CAA, Pepco Energy Services received authorization in 2013 from the District Department of the Environment (DDOE) to exclude these major sources from the CAA Title V operating permits. DDOE also agreed to transfer the CAA Title V operating permit covering the remaining minor sources (e.g., Pepco-operated emergency generators) to Pepco. Pepco has filed minor source permit applications with DDOE for these minor sources.

Greenhouse Gas Emissions Reporting

In October 2009, the U.S. Environmental Protection Agency (EPA) adopted regulations requiring sources that emit designated greenhouse gases – specifically, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and other fluorinated gases (e.g., nitrogen trifluoride and hydrofluorinated ethers) – in excess of specified thresholds to file annual reports with EPA disclosing the amount of such emissions. Under these regulations:

- For the operating period ending with the two oil-fired generating units' deactivation in June 2012, Pepco Energy Services reported CO_2, methane and nitrous oxide for its Benning Road units.

- By April 1 of each year, DPL is required to report with respect to its gas distribution operations CO_2 emissions that would result assuming the complete combustion or oxidation of the annual volume of natural gas it distributed to its customers during the previous calendar year. In addition, DPL is required to report fugitive CO_2 and methane emissions for its gas distribution operations for the previous calendar year. DPL's liquefied natural gas storage facility does not meet the reporting threshold (25,000 metric tons) for fugitive emissions.
- By April 1 of each year, Pepco, DPL and ACE are required to report sulfur hexafluoride emissions from electrical equipment for the previous calendar year.

<u>*Water Quality Regulation*</u>

Clean Water Act

Provisions of the federal Water Pollution Control Act, also known as the Clean Water Act, establish the basic legal structure for regulating the discharge of pollutants from point sources to surface waters of the United States. Among other things, the Clean Water Act requires that any person wishing to discharge pollutants from a point source (generally a confined, discrete conveyance such as a pipe) obtain a National Pollutant Discharge Elimination System (NPDES) permit issued by EPA or by a state agency under a federally authorized state program.

Pepco holds a NPDES permit issued by EPA with a July 19, 2009 effective date, which authorizes discharges from the Benning Road facility, including the now deactivated Pepco Energy Services generating facility located at that site. The permit imposes compliance monitoring and storm water best management practices to satisfy the District of Columbia's Total Maximum Daily Load (TMDL) standards for polychlorinated biphenyls, oil and grease, metals and other substances. As required by the permit, Pepco has initiated a study to identify the source of the regulated substances to determine appropriate best management practices for minimizing the presence of the substances in storm water discharges from the facility. The initial study report was completed in May 2012. Pepco has completed the implementation of the first two phases of the best management practices recommended in the study report (consisting principally of installing metal absorbing filters to capture contaminants from storm water flows, removing stored equipment from areas exposed to the weather, covering and painting exposed metal pipes, and covering and cleaning dumpsters). Pepco will be evaluating the effectiveness of these initial best management practices and will consult with EPA regarding the need for additional measures. The capital expenditures, if any, that may be needed to implement additional best management practices to satisfy TMDL requirements will not be known until Pepco and EPA have completed the assessment of the effectiveness of these initial best management practices. In December 2013, Pepco filed an application with EPA to renew this permit, which is scheduled to expire on June 19, 2014.

EPA Oil Pollution Prevention Regulations

Facilities that, because of their location, store or use oil and could reasonably be expected to discharge oil into water bodies or adjacent shorelines in quantities that may be harmful to the environment are subject to EPA's oil pollution prevention regulations. These regulations require entities to prepare and implement Spill Prevention, Control, and Countermeasure (SPCC) plans and specify site-specific measures to prevent and respond to an oil discharge. The SPCC regulations generally require the use of containment and/or diversionary structures to prevent the discharge of oil in the event of a leak or release of oil at the facility. As an alternative to the containment/diversionary structure requirement, owners of certain oil-filled operational equipment, such as electric system transformers, may comply with EPA's regulations by implementing an inspection and monitoring program, developing an oil spill contingency plan, and providing a written commitment of resources to control and remove any discharge of oil. Pepco, DPL and ACE are complying with the SPCC regulations by employing containment/diversionary structures and by means of inspection and monitoring measures, in each case where such measures have been determined to be appropriate. Total costs of complying with these regulations in 2013 for Pepco, DPL and ACE collectively were approximately $6.6 million. PHI projects total expenditures of approximately $22.5 million over the next five years for its subsidiaries to comply with these regulations, as shown in the capital expenditure projection set forth in "Environmental Matters" above, all of which are to install additional containment facilities and to replace certain oil-filled breakers with gas-filled breakers to eliminate the possibility of an oil release from such equipment. Compliance costs for Pepco Energy Services have not been material, and PHI does not expect that they will become material in the foreseeable future.

Hazardous Substance Regulation

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) authorizes EPA, and comparable state laws authorize state environmental authorities, to issue orders and bring enforcement actions to compel responsible parties to investigate and take remedial actions at any site that is determined to present an actual or potential threat to human health or the environment because of an actual or threatened release of one or more hazardous substances. Parties that generated or transported hazardous substances to such sites, as well as the owners and operators of such sites, may be deemed liable under CERCLA or comparable state laws. Each of Pepco, DPL and ACE has been named by EPA or a state environmental agency as a potentially responsible party in pending proceedings involving certain contaminated sites. For additional information on these matters, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Capital Requirements – Environmental Remediation Obligations," and Note (15), "Commitments and Contingencies – Environmental Matters," to the consolidated financial statements of PHI.

Employees

At December 31, 2013, PHI had the following employees:

		In Collective Bargaining Agreements			
	Non-union	International Brotherhood of Electrical Workers	International Union of Operating Engineers	Other	Total
Pepco	372	1,099	—	—	1,471
DPL	230	650	—	—	880
ACE	191	353	—	—	544
Pepco Energy Services	161	238	42	31	472
PHI Service Company and Other	1,359	299	—	—	1,658
Total PHI Employees	2,313	2,639	42	31	5,025

PHI's subsidiaries are parties to five collective bargaining agreements with four local unions. Collective bargaining agreements are generally renegotiated every three to five years.

Executive Officers of PHI

The names of the executive officers of PHI, their ages and the positions they held as of February 26, 2014, are set forth in the following table. The business experience of each executive officer during the past five years is set forth adjacent to his or her name under the heading "Office and Length of Service" in the following table and in the applicable footnote.

Name	Age	Office and Length of Service
Joseph M. Rigby	57	**Chairman of the Board** 5/09 - Present, **President** 3/08 - Present, and **Chief Executive Officer** 3/09 -Present (1)
David M. Velazquez	54	**Executive Vice President** 3/09 - Present (2)
Kevin C. Fitzgerald	51	**Executive Vice President and General Counsel** 9/12 - Present (3)
Frederick J. Boyle	56	**Senior Vice President and Chief Financial Officer** 4/12 - Present (4)
Kenneth J. Parker	51	**Senior Vice President, Government Affairs and Corporate Citizenship** 9/12 - Present (5)
Thomas H. Graham	53	**Vice President** 8/13 - Present (6)
Ronald K. Clark	58	**Vice President and Controller** 8/05 - Present
Laura L. Monica	57	**Vice President** 8/11 - Present (7)
Hallie M. Reese	50	**Vice President, PHI Service Company** 5/05 - Present
John U. Huffman	54	**President** 6/06 - Present, and **Chief Executive Officer, Pepco Energy Services, Inc.** 3/09 - Present (8)

(1) Mr. Rigby was Chief Operating Officer of PHI from September 2007 until February 28, 2009 and Executive Vice President of PHI from September 2007 until March 2008, Senior Vice President of PHI from August 2002 until September 2007 and Chief Financial Officer of PHI from May 2004 until September 2007. Mr. Rigby was President and Chief Executive Officer of Pepco, DPL and ACE from September 1, 2007 to February 28, 2009. Mr. Rigby has been Chairman of Pepco, DPL and ACE since March 1, 2009. On January, 24, 2014, Mr. Rigby notified PHI that he would be stepping down from his positions as President and Chief Executive Officer of PHI by the end of 2014 and would remain employed by PHI through May 1, 2015 to facilitate the transition of these roles. Mr. Rigby intends to remain as PHI's Chairman of the Board through the 2015 Annual Meeting of Stockholders.

(2) Mr. Velazquez served as President of Conectiv Energy Holding Company, formerly an affiliate of PHI, from June 2006 to February 28, 2009, Chief Executive Officer of Conectiv Energy Holding Company from January 2007 to February 28, 2009 and Chief Operating Officer of Conectiv Energy Holding Company from June 2006 to December 2006.

(3) Mr. Fitzgerald joined PHI in September 2012 as Executive Vice President and General Counsel. Prior to such time, he was a partner with the law firm of Troutman Sanders, LLP in Washington, D.C. since 1997. Mr. Fitzgerald was Managing Partner of that firm's Washington, D.C. office from 1999 until 2010 and Executive Partner for Client Development Strategic Planning from 2010 to September 2012.

(4) Mr. Boyle joined PHI in April 2012 as Senior Vice President and Chief Financial Officer. Prior to such time, he served as Senior Vice President and Chief Financial Officer of DPL Inc. and its wholly owned utility subsidiary, The Dayton Power and Light Company, from December 2010 until its acquisition in 2011. He served as Senior Vice President, Chief Financial Officer and Treasurer of both companies from May 2009 to December 2010, Senior Vice President, Chief Financial Officer, Treasurer and Controller of both companies from December 2008 to May 2009, Vice President, Finance, Chief Accounting Officer and Controller of both companies from June 2008 to November 2008, Vice President, Chief Accounting Officer and Controller of both companies from July 2007 to June 2008, and Vice President and Chief Accounting Officer of both companies from June 2006 to July 2007.
(5) Mr. Parker became Senior Vice President, Government Affairs and Corporate Citizenship effective September 1, 2012. Prior to such time, he served as Vice President of Public Policy from June 2009 to September 2012 and the ACE Region President from March 2005 to June 2009.
(6) Mr. Graham became Vice President, People Strategy and Human Resources effective August 1, 2013. Prior to such time, he served as the Pepco Region President from March 2005 to August 2013.
(7) Ms. Monica joined PHI in August 2011 as Vice President, Corporate Communications. From October 2006 to October 2010, Ms. Monica was Senior Vice President, Corporate Communications at American Water Works Company (NYSE: AWK), and from September 1991 to October 2006, Ms. Monica was President of High Point Communications, a strategic communications firm. Ms. Monica rejoined High Point Communications as President from October 2010 to August 2011.
(8) Mr. Huffman has been employed by Pepco Energy Services since June 2003. He was Chief Operating Officer from April 2006 to February 28, 2009, Senior Vice President from February 2005 to March 2006 and Vice President from June 2003 to February 2005.

Each PHI executive officer is elected annually and serves until his or her respective successor has been elected and qualified or his or her earlier resignation or removal.

Investor Information

Each Reporting Company maintains an Internet web site, at the Internet address listed below:

Reporting Company	Internet Address
PHI	http://www.pepcoholdings.com
Pepco	http://www.pepco.com
DPL	http://www.delmarva.com
ACE	http://www.atlanticcityelectric.com

Each Reporting Company files reports with the SEC under the Exchange Act. Copies of the Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports, of each Reporting Company are routinely made available free of charge on PHI's Internet Web site (http://www.pepcoholdings.com/investors) as soon as reasonably practicable after such documents are electronically filed with or furnished to the SEC. 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. The information contained on the web sites listed above shall not be deemed incorporated into, or to be part of, this Annual Report on Form 10-K, and any web site references included herein are not intended to be made through active hyperlinks.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL, AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND THEREFORE ARE FILING THIS FORM WITH THE REDUCED FILING FORMAT.

Item 1A. RISK FACTORS

The businesses of each Reporting Company are subject to numerous risks and uncertainties, including the events or conditions identified below. The occurrence of one or more of these events or conditions could have an adverse effect on the business of any one or more of the Reporting Companies, including, depending on the circumstances, its financial condition, results of operations and cash flow. Unless otherwise noted, each risk factor set forth below applies to each Reporting Company.

PHI's utility subsidiaries are subject to comprehensive regulation which significantly affects 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 including setting rates at a level that may be inadequate to permit recovery of costs 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.

NERC's eight regional oversight entities, including RFC, of which Pepco, DPL, ACE and Pepco Energy Services are members, and the 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's utility subsidiaries to obtain timely recognition of costs in 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, DPL and ACE 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.

For example, PHI's utility subsidiaries are exposed to "regulatory lag," which refers to a shortfall in revenues in a utility's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. All of PHI's utilities are currently experiencing significant regulatory lag because their investments in rate base and operating expenses are increasing more rapidly than their 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.

Each of PHI's utility subsidiaries will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag and have an opportunity to earn its authorized return on equity. See Part I, Item 1. "Business – Regulation – Mitigation of Regulatory Lag." There can be no assurance that any attempts by Pepco, DPL and ACE to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. The inability of PHI's utility subsidiaries to obtain relief from the impact of regulatory lag through base rate cases or otherwise may have a material adverse effect on the business, results of operations, cash flow and financial condition of PHI and each utility subsidiary.

The operating results of Power Delivery fluctuate on a seasonal basis and can be adversely affected by changes in weather.

The Power Delivery business historically has been seasonal and, as a result, weather has had a material impact on its operating performance. Demand for electricity is generally higher in the summer months associated with cooling and demand for electricity and natural gas is generally higher in the winter months associated with heating as compared to other times of the year. Accordingly, each of PHI, Pepco, DPL and ACE historically has generated less revenue and income when temperatures are warmer in the winter and cooler in the summer. In addition, severe weather conditions can produce storms that cause extensive damage to the transmission and distribution systems, as well as related facilities, that can require the utilities to incur additional operation and maintenance expense, as well as capital expenditures. These additional costs can be significant and the rates charged to customers may not always be timely or adequately adjusted to reflect these higher costs.

In the District of Columbia and Maryland, Pepco and DPL are subject to a bill stabilization adjustment mechanism applicable to retail customers, which decouples distribution revenue for a given reporting period from the amount of power delivered during the period. The bill stabilization mechanism has the effect in those jurisdictions of reducing the impact of changes in the use of electricity by retail customers due to weather conditions or for other reasons on reported distribution revenue and income. A comparable revenue decoupling mechanism for DPL electricity and natural gas customers in Delaware is under consideration by the DPSC. In those jurisdictions that have not adopted a bill stabilization adjustment or similar mechanism, operating results continue to be affected by weather conditions.

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

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

In connection with the replacement of certain customers' existing electric and natural gas meters with smart meters as part of the AMI system, Pepco and DPL were required to construct a wireless network across certain of their service territories and to implement and integrate new and existing information technology systems to collect and manage data made available by the smart meters and the AMI system. The implementation of the AMI system involves a combination of technologies provided by multiple vendors. If the AMI system results in lower than projected performance, PHI's utility subsidiaries could experience higher than anticipated maintenance expenditures.

Energy companies are subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other sanctions.

Utility companies, including PHI's utility subsidiaries, have a large consumer customer base and as a result have been the subject of public criticism focused on the reliability of their distribution services and the speed with which they are able to respond to outages caused by storm damage or other unanticipated events. Adverse publicity of this nature may render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view energy companies such as PHI and its subsidiaries in a favorable light, and may cause PHI and its subsidiaries to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent regulatory requirements. Unfavorable regulatory outcomes can include the enactment of more stringent laws and regulations governing PHI's operations, such as reliability and customer service quality standards or vegetation management requirements, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material negative impact on PHI's and each utility subsidiary's business, results of operations, cash flow and financial condition.

Unfavorable regulatory developments and compliance with new or more rigorous regulatory requirements will subject PHI's utility subsidiaries to higher operating costs.

PHI's utility subsidiaries are subject to and will continue to be subject to changing regulatory requirements, including those related to reliability and customer service, in the various jurisdictions in which they operate. For example, in 2012, the MPSC adopted rules establishing reliability and customer service requirements. In April 2014, DPL expects to file an annual report with the MPSC in which it will indicate that it was not in compliance with certain of these reliability requirements for 2013. In addition, in July 2011, the DCPSC adopted regulations that establish specific maximum outage frequency and outage duration levels beginning in 2013 and continuing through 2020 and thereafter and are intended to require Pepco to achieve a reliability level in the first quartile of all utilities in the nation by 2020. Pepco believes that the DCPSC's standards are achievable in the short term, but believes that the standards may not be realistically achievable at an acceptable cost over the longer term. The reliability standards permit Pepco to petition the DCPSC to reevaluate these standards for the period from 2016 to 2020 to address feasibility and cost issues.

Each of Pepco and DPL expect that it will have to incur significant operating and maintenance and capital expenses to comply with these requirements. Furthermore, each of Pepco and DPL would be subject to civil penalties or other sanctions if it does not meet the required performance or reliability standards. Other jurisdictions in which PHI's utility subsidiaries have operations have already adopted or may in the future adopt reliability and customer service quality standards, the violation of which could also result in the imposition of penalties, fines and other sanctions. Compliance, and any failure to comply, with current, proposed or future regulatory requirements may have a material adverse effect on PHI and each utility subsidiary's business, results of operations, cash flow and financial condition.

The resolution of tax matters involving PHI's former cross-border energy lease investments may have a material negative impact on PHI's results of operations and financial condition. (PHI only).

Prior to July 2013, a wholly-owned subsidiary of PHI had maintained a portfolio of cross-border energy lease investments involving public utility assets located outside of the United States, which investments were terminated during the third quarter of 2013 prior to the expiration date of the leases. The aggregate financial impact to PHI of the completion of these early terminations resulted in a pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax) for the year ended December 31, 2013.

These cross-border energy lease investments, each of which was with a tax-indifferent party, have been under examination by the IRS as part of normal PHI federal income tax audits. In connection with the audits of PHI's federal income tax returns from 2001 to 2008, the IRS disallowed the depreciation and interest deductions in excess of rental income claimed by PHI with respect to its cross-border energy lease investments. In addition, the IRS has sought to recharacterize the leases as loan transactions. In January 2012, PHI commenced litigation in the U.S. Court of Federal Claims regarding the disallowance of certain tax benefits claimed by PHI on its federal tax returns for 2001 and 2002.

In January 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in an unrelated case that disallowed tax benefits associated with a lease-in, lease-out transaction. After analyzing this ruling, in the first quarter of 2013, PHI determined that its tax position with respect to the tax benefits associated with its cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded non-cash charges of $383 million (after-tax) in the first half of 2013, consisting of a non-cash charge to reduce the carrying value of the cross-border energy lease investments and a non-cash charge to reflect the anticipated additional interest expense related to changes in estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed.

After consideration of certain tax benefits arising from matters unrelated to these lease investments, PHI estimated that, as of March 31, 2013, it would have been obligated to pay approximately $192 million in additional federal and state taxes and approximately $50 million of interest on the additional federal and state taxes. In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made an advanced payment to the IRS of $242 million in the first quarter of 2013. While PHI presently believes that it is more likely than not that no penalty will be incurred, the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due. In order to mitigate the cost of continued litigation related to the cross-border energy lease investments, PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues for open tax years 2001 through 2011, including the cross-border energy lease issue. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014. If a settlement of all tax issues or a standalone settlement on the cross-border energy leases is not reached, PHI may move forward with its litigation with the IRS. Further discovery in the case is stayed until April 24, 2014, pursuant to an order issued by the court on January 30, 2014.

Given the uncertainties associated with PHI's litigation with the IRS, as well as with other efforts by PHI to address and resolve tax matters associated with its former cross-border energy leases in tax years not subject to this litigation, the aggregate financial impact, and timing of the resolution, of all of these matters cannot be determined presently; however, PHI presently believes that any such impact on PHI's consolidated results of operations and financial condition could be material.

Power Delivery's transmission facilities are interconnected with the facilities of other transmission facility owners. Failures of neighboring transmission systems could have a negative impact on Power Delivery's operations.

The electricity transmission facilities of Pepco, DPL and ACE are interconnected with the transmission facilities of neighboring utilities and are part of the interstate power transmission grid. Pepco, DPL and ACE are members of the PJM RTO, a regional transmission organization that operates the portion of the interstate transmission grid that includes the PHI transmission facilities. Although PJM's systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities, there can be no assurance that service interruptions originating at other utilities will not cause interruptions in the Pepco, DPL or ACE service territories. Thus, due to the interconnected nature of the interstate power transmission grid, an outage in a neighboring utility could trigger a system outage in either Pepco, DPL or ACE. If Pepco, DPL or ACE were to suffer such a service interruption, it could have a negative impact on its and PHI's business, results of operations, cash flow and financial condition.

Changes in technology, distributed generation and conservation measures may adversely affect Power Delivery.

Increased conservation and end-user generation made possible through current or future advances in technology, such as through fuel and solar (photovoltaic) cells, wind power and microturbines, could reduce demand for the transmission and distribution facilities of Power Delivery and adversely affect the results of operations of PHI and one or more of its utility subsidiaries. Alternative technologies that produce electricity, the development of which has expanded due to climate change and other environmental concerns, could ultimately provide alternative sources of electricity and permit current customers to adopt distributed generation systems which would allow them to generate electricity for their own use. As these and other technologies are created, developed and improved, the quantity and frequency of electricity usage by customers could decline, which could have a negative impact on the business, results of operations, cash flow and financial condition of PHI or its utility subsidiaries.

The cost of compliance with environmental laws is significant and implementation of new and existing environmental laws may increase operating costs.

The operations of PHI's subsidiaries are subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, spill prevention, waste management, natural resource protection, site remediation, greenhouse gas emissions and health and safety. These laws and regulations may require significant capital and other expenditures to, among other things, meet emissions and effluent standards, conduct site remediation, complete environmental studies and perform environmental monitoring. If a company fails to comply with applicable environmental laws and regulations, even if caused by factors beyond its control, such failure could result in the assessment of civil or criminal penalties and liabilities and the need to expend significant sums to achieve compliance.

In addition, PHI's subsidiaries are required to obtain and comply with a variety of environmental permits, licenses, inspections and other approvals. If there is a delay in obtaining any required environmental regulatory approval, or if there is a failure to obtain, maintain or comply with any such approval, operations at affected facilities could be halted or subjected to additional costs.

Failure to retain and attract key skilled and properly motivated professional and technical employees could have an adverse effect on operations.

PHI and its subsidiaries operate in a highly regulated industry that requires the continued operation of sophisticated systems and technology. One of the challenges they face in implementing their business strategy is to attract, motivate and retain a skilled, efficient and cost-effective workforce while recruiting new talent to replace losses in knowledge and skills due to retirements. Over the course of the next three years, PHI estimates that approximately one-third of this skilled workforce will reach retirement age. Competition for skilled employees in some areas is high and the inability to attract and retain these employees, especially as existing skilled workers retire in the near future, could adversely affect the business, operations and financial condition of PHI or the affected company.

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

As of December 31, 2013, 54% of employees of PHI and its subsidiaries, collectively, were represented by various labor unions. PHI's subsidiaries are parties to five collective bargaining agreements with four local unions that represent these employees. Collective bargaining agreements are generally renegotiated every three to five years, and the risk exists that there could be a work stoppage after expiration of an agreement until a new collective bargaining agreement has been reached. Labor negotiations typically involve bargaining over wages, benefits and working conditions, including management rights. PHI's last work stoppage, a two-week strike by DPL's employees, occurred in 2010. During that strike, DPL used management and contractor employees to maintain essential operations. Though PHI believes that protracted work stoppages are unlikely, such an event could result in a disruption of the operations of the affected utility, which could, in turn, have a material adverse effect upon the business, results of operations, cash flow and financial condition of the affected utility and PHI.

The energy savings business of Pepco Energy Services is highly competitive and its thermal operation in Atlantic City is exposed to customer concentration. (PHI only)

Unlike PHI's regulated business, Pepco Energy Services' energy savings business is unregulated and its energy savings performance contracting business is highly competitive. This competition puts downward pressure on margins and increases costs. The energy savings business is affected by new entrants into the market, financial strength of customers, energy prices and general economic conditions. These factors may negatively affect Pepco Energy Services' ability to market its services to new customers or renew existing contracts, as well as the prices Pepco Energy Services may charge.

Among the factors on which the energy savings business competes are the amount and duration of the guarantees provided in energy savings performance contracts. In connection with many of its energy savings performance installation projects, Pepco Energy Services guarantees a minimum level of annual energy cost savings over a period of typically up to 15 years. Currently, Pepco Energy Services does not insure against this risk, and accordingly could suffer financial losses if a project does not achieve the guaranteed level of performance.

Under the Budget Control Act of 2011, mandatory federal spending cuts, also known as “sequestration,” are effective for years 2013 through 2021 unless Congress agrees to a deficit reduction plan. In January 2013, Congress passed, and the President signed, the American Taxpayer Relief Act of 2012 that addressed rising federal income tax rates that would have taken effect on January 1, 2013. Although Congress has enacted the Consolidated Appropriations Act of 2014, which is expected to alleviate the effects of sequestration on the Department of Defense through October 2014, the continuation of other substantial federal spending cuts could make it more difficult for Pepco Energy Services to enter into new energy savings performance contracts with federal, state and local government agencies and thus could have a material adverse effect on the energy savings business of Pepco Energy Services.

In addition, revenues associated with Pepco Energy Services’ combined heat and power thermal generating plant and operation in Atlantic City, New Jersey are concentrated with a few major customers in the Atlantic City hotel and casino industry. Pepco Energy Services has long-term contracts with these customers, and for the largest customer, the contracts expire in 2017. The Atlantic City hotel and casino industry has been experiencing a decrease in gaming revenues and overcapacity, as well as potential future competition from casinos that are being constructed in nearby markets. Pepco Energy Services is exposed to the risk that it is not able to renew these contracts or that the contract counterparties may fail to perform their obligations thereunder. In either case, Pepco Energy Services may be required to conclude that the assets with an aggregate carrying value as of December 31, 2013 of approximately $85 million associated with the generating plant or operation have been impaired, which would require Pepco Energy Services to reduce the carrying value of these assets by the amount of the impairment and record a corresponding non-cash charge to earnings. Any of these events could have a material adverse effect on PHI’s and Pepco Energy Services’ financial condition, results of operations and cash flow.

Under its energy savings performance contracts, Pepco Energy Services is responsible for maintaining, repairing and replacing energy equipment, which obligations may require Pepco Energy Services to incur significant costs many years after an installation of a project is completed. (PHI only)

Pepco Energy Services owns energy equipment and is also responsible for operating and maintaining additional energy equipment that it does not own. In addition, it is generally Pepco Energy Services’ responsibility to repair or replace this energy equipment in the event of a failure. These equipment maintenance, repair and replacement obligations could be material and could adversely affect PHI’s results of operations, cash flow and financial condition.

Pepco Energy Services’ obligations in connection with its combined heat and power construction projects, energy savings construction projects and energy savings performance contracts may have a material adverse effect on PHI. (PHI only)

Pepco Energy Services has undertaken projects which include design, construction, startup and testing activities related to combined heat and power and energy savings construction projects, pursuant to guaranteed maximum price or fixed-price contracts. Pepco Energy Services will generally secure commitments from subcontractors and vendors to perform within contract pricing commitments, equipment-performance standards, jobsite safety requirements, and other key parameters. Under a number of these projects, the customer of Pepco Energy Services has required Pepco Energy Services to obtain surety bonds securing the performance of Pepco Energy Services, or its subcontractors or vendors. PHI has been required to guarantee the performance of Pepco Energy Services under the surety bonds and certain of these construction contracts. PHI also guarantees the obligations of Pepco Energy Services under certain of its energy savings performance contracts. At December 31, 2013, PHI's guarantees of Pepco Energy Services' obligations under its energy savings performance, combined heat and power, and construction contracts totaled $190 million, and PHI's guarantees of Pepco Energy Services' obligations under surety bonds for construction projects totaled $229 million.

As a result, PHI may bear responsibility in the event of unexcused failures by Pepco Energy Services or its subcontractors or vendors to perform in accordance with the terms of these contracts, or if the customer does not realize the energy savings provided for in a performance contract. When such events occur, Pepco Energy Services and PHI may experience reputational harm and claims for money damages and other relief that may be sought in connection with such contracts, guarantees and surety bonds, which could, depending upon the nature of the claim and the amount of damages or other relief sought, have a material adverse effect upon Pepco Energy Services' and PHI's business, results of operations, cash flow and financial condition.

If PHI is not successful in mitigating the risks inherent in its business, its operations could be adversely affected.

PHI and its subsidiaries are faced with a number of different types of risk. PHI confronts legislative, regulatory policy, compliance and other risks, including:

- PHI's inability to timely recover capital and operating costs, which may result in a shortfall in revenues;
- resource planning and other long-term planning risks, including resource acquisition risks, which may hinder PHI's ability to maintain adequate resources;
- financial risks, including credit, interest rate and capital market risks, which could increase the cost of capital or make raising capital more difficult; and
- macroeconomic risks, and risks related to economic conditions and changes in demand for electricity and natural gas in the service territories of PHI's utility subsidiaries (including changes due to or in connection with the loss of one or more commercial customers of a utility subsidiary), as well as with respect to Pepco Energy Services' business, which could negatively impact the operations of the affected business.

PHI management seeks to mitigate the risks inherent in the implementation of PHI's business strategy through its established risk mitigation process, which includes adherence to PHI's business policies and other compliance policies, operation of formal risk management structures and groups, and overall business management. PHI management is responsible for identifying, assessing and managing risks, and developing risk-management strategies, while the Board of Directors and its various committees oversee the assessment, management and mitigation of risk. However, there can be no assurance these risk mitigation efforts will adequately address all such risks or that such efforts will be successful, and a failure to successfully mitigate such risks may have a material adverse effect on the business, results of operations, cash flow or financial condition of one or more of the Reporting Companies.

PHI and its subsidiaries are exposed to contractual and credit risks associated with certain of their operations.

PHI and its subsidiaries are subject to a number of contractual and credit risks associated with certain of their operations. To mitigate contractual or credit risk, PHI or a subsidiary may give to or receive from the counterparty collateral or other types of performance assurance, which may be in the form of cash, letters of credit or parent guarantees, to protect against performance and credit risk. Even where collateral is provided, capital market disruptions, the lowered rating or insolvency of the issuer or guarantor, changes in the power supply market prices and other events may prevent a party from being able to meet its obligations or may degrade the value of collateral, letters of credit and guarantees, and the collateral, guarantee or other performance assurance provided may prove insufficient to protect against all losses that a party may ultimately suffer. In the event of a bankruptcy of a counterparty to any contract to which PHI or any of its subsidiaries is a party, bankruptcy law, in some circumstances, could require the surrender of collateral or other guarantees held or payments received.

Business operations could be adversely affected by terrorism and cyber attacks.

The threat of, or actual acts of, terrorism may affect the operations of PHI and its subsidiaries in unpredictable ways and may cause changes in the insurance markets, force an increase in security measures and cause electrical disruptions or disruptions of fuel supplies and markets, including natural gas. Utility industry operations require the continued deployment and utilization of sophisticated information technology systems and network infrastructure. While PHI has implemented protective measures designed to mitigate its vulnerability to physical and cyber threats and attacks, such protective measures, and technology systems generally, are vulnerable to disability or failure due to cyber attack, acts of war or terrorism, and other causes. As a result, there can be no assurance that such protective measures will be completely effective in protecting PHI's infrastructure or assets from a physical or cyber attack or the effects thereof. If any of Pepco's, DPL's or ACE's infrastructure facilities, including their transmission or distribution facilities, were to be a direct target, or an indirect casualty, of an act of terrorism, the operations of PHI, Pepco, DPL or ACE could be adversely affected. Furthermore, any threats or actions that negatively impact the physical security of PHI's and its subsidiaries' facilities, or the integrity or security of their computer networks and systems (and any programs or data stored thereon or therein), could adversely affect PHI's and its subsidiaries' ability to manage these facilities, networks, systems, programs and data efficiently or effectively, which in turn could have a material adverse effect on PHI's or its subsidiaries' results of operations and financial condition. Corresponding instability in the financial markets as a result of threats or acts of terrorism or threatened or actual cyber attacks also could adversely affect the ability of PHI or its subsidiaries to raise needed capital.

New accounting standards or changes to existing accounting standards could materially impact how a Reporting Company reports its results of operations, cash flow and financial condition.

Each Reporting Company's financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The SEC, the Public Company Accounting Oversight Board, the Financial Accounting Standards Board (FASB) or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require the Reporting Companies to change their accounting policies. These changes are beyond the control of the Reporting Companies, can be difficult to predict and could materially impact how they report their results of operations, cash flow and financial condition. Each Reporting Company could be required to apply a new or revised standard retroactively, which could adversely affect its results of operations, cash flow and financial condition.

Undetected errors in internal controls and information reporting could result in the disallowance of cost recovery and noncompliant disclosure.

Each Reporting Company's internal controls, accounting policies and practices and internal information systems are designed to enable the Reporting Company to capture and process transactions and information in a timely and accurate manner in compliance with GAAP, taxation requirements, federal securities laws and regulations and other laws and regulations (including pursuant to federal and state administrative grant programs) applicable to it. Such compliance permits each Reporting Company to, among other things, disclose and report financial and other information in connection with the recovery of its costs and with the reporting requirements for each Reporting Company under federal securities, tax and other laws and regulations.

Each Reporting Company has implemented corporate governance, internal control and accounting policies and procedures in connection with the Sarbanes-Oxley Act of 2002 (the Sarbanes-Oxley Act) and relevant SEC rules, as well as other applicable regulations. Such internal controls and policies have been and continue to be closely monitored by each Reporting Company's management and PHI's Board of Directors to ensure continued compliance with these laws, rules and regulations. Management is also responsible for establishing and maintaining internal control over financial reporting and is required to assess annually the effectiveness of these controls. While PHI believes these controls, policies, practices and systems are adequate to verify data integrity, unanticipated and unauthorized actions of employees or temporary lapses in internal controls due to shortfalls in oversight or resource constraints could lead to undetected errors that could result in the disallowance of cost recovery and noncompliant disclosure and reporting. The consequences of these events could have a negative impact on the results of operations and financial condition of the affected Reporting Company. The inability of management to certify as to the effectiveness of these controls due to the identification of one or more material weaknesses in these controls could also increase financing costs or could also adversely affect the ability of a Reporting Company to access the capital markets.

Insurance coverage may not be sufficient to cover all casualty or property losses that PHI and its subsidiaries might incur.

PHI and its subsidiaries, including Pepco, DPL and ACE, as well as Pepco Energy Services, currently have insurance coverage for their facilities and operations in amounts and with deductibles that they consider appropriate. However, there is no assurance that such insurance coverage will be available in the future on commercially reasonable terms or at all. In addition, some risks and losses, such as weather related casualties, may not be insurable, and, where a risk has been insured, a risk or loss may be deemed to be excluded from coverage or coverage may otherwise be denied in whole or in part. In the case of loss or damage to property, plant, equipment or other assets, there is no assurance that the insurance proceeds received, if any, will be sufficient to cover the entire loss, including costs of replacement or repair.

PHI and its subsidiaries are dependent on obtaining access to the capital markets and bank financing to satisfy their capital and liquidity requirements. The inability to obtain required financing when needed would have an adverse effect on their respective businesses.

PHI and its subsidiaries, including Pepco, DPL and ACE, have significant capital requirements, including the funding of construction expenditures and the refinancing of maturing debt. Each of the Reporting Companies relies primarily on cash flow from operations, access to the capital markets and medium- and long-term bank financing, to meet these long-term financing needs. The operating activities of PHI and its subsidiaries also require continued access to short-term sources of liquidity, including issuances by a Reporting Company of commercial paper and access to money markets and short-term bank financing, to provide for short-term liquidity needs that are not met by cash flows from their operations. Adverse business developments or market disruptions could increase the cost of financing or prevent PHI or any of its subsidiaries from accessing these sources of short-term and long-term capital. Events that could cause or contribute to a disruption of the financial markets include, but are not limited to:

- a recession or an economic slowdown;
- the bankruptcy of one or more energy companies or financial institutions;
- a significant change in energy prices;
- a terrorist or cyber attack or threatened attacks;
- the outbreak of a pandemic or other similar event; or
- a significant electricity or natural gas transmission disruption.

Any reductions in or other actions with respect to the credit ratings of PHI or any of its subsidiaries could increase its financing costs and the cost of maintaining certain contractual relationships.

Nationally recognized rating agencies currently rate each Reporting Company and debt securities issued by Pepco, DPL and ACE. Ratings are not recommendations to buy or sell securities. PHI or its subsidiaries may, in the future, incur new indebtedness with interest rates that may be affected by changes in or other actions associated with these credit ratings. Each of the rating agencies reviews its ratings periodically, and previous ratings may not be maintained in the future. Rating agencies may also place a Reporting Company under review for potential downgrade in certain circumstances or if any of them seek to take certain actions that it believes would otherwise be in its best interests. A downgrade of these debt ratings or other negative action, such as a review for a potential downgrade, could affect the market price of existing indebtedness and the ability to raise additional debt without incurring increases in the cost of capital. In addition, a downgrade of these ratings, or other negative action, could make it more difficult to raise capital to refinance any maturing debt obligations, to support business growth and to maintain or improve the current financial strength of PHI's business and operations.

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

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

Each borrower's ability to comply with this covenant is subject to various risks and uncertainties, including events beyond the borrower's control. For example, events that could cause a reduction in PHI's equity include, without limitation, potential IRS taxes, interest and penalties associated with PHI's former 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 limitations on its operational and financial flexibility 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's cash flow, ability to pay dividends and ability to satisfy debt obligations depend on the performance of its regulated and competitive operating subsidiaries, access to the capital markets and other sources of liquidity. PHI's unsecured obligations are effectively subordinated to the liabilities of its subsidiaries. (PHI only)

PHI is a holding company that conducts its operations entirely through its regulated and competitive subsidiaries, and all of PHI's consolidated operating assets are held by its subsidiaries. Accordingly, PHI's cash flow, its ability to satisfy its obligations to creditors and its ability to pay dividends on its common stock are dependent upon the earnings of its subsidiaries, each Reporting Company's access to the capital markets and all sources of cash flow and liquidity that may be available to PHI. PHI's subsidiaries are separate legal entities and have no obligation to pay any amounts due on any debt or equity securities issued by PHI or to make any funds available for such payment. The ability of PHI's subsidiaries to pay dividends and make other payments to PHI may be restricted by, among other things, applicable corporate, tax and other laws and regulations and agreements made by PHI and its subsidiaries, including under the terms of indebtedness, and PHI's financial objective of maintaining a common equity ratio at its utility subsidiaries of between 49% and 50%. Because the claims of the creditors of PHI's subsidiaries are superior to PHI's entitlement to dividends, the unsecured debt and obligations of PHI are effectively subordinated to all existing and future liabilities of its subsidiaries, including trade creditors. In addition, claims of creditors, including trade creditors, of PHI's subsidiaries will generally have priority with respect to the assets and earnings of such subsidiaries over the claims of PHI's creditors.

PHI has a significant goodwill balance related to its Power Delivery business. A determination that goodwill is impaired could result in a significant non-cash charge to earnings.

PHI had a goodwill balance at December 31, 2013, of approximately $1.4 billion, primarily attributable to Pepco's acquisition of Conectiv in 2002. An impairment charge must be recorded under GAAP to the extent that the implied fair value of goodwill is less than the carrying value of goodwill, as shown on the consolidated balance sheet. PHI is required to test goodwill for impairment at least annually and whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Factors that may result in an interim impairment test include, but are not limited to: an adverse change in business conditions; a protracted decline in stock price causing market capitalization to fall significantly below book value; an adverse regulatory action; impairment of long-lived assets in the reporting unit; or a change in identified reporting units. If PHI were to determine that its goodwill is impaired, PHI would be required to reduce its goodwill balance by the amount of the impairment and record a corresponding non-cash charge to earnings. Depending on the amount of the impairment, an impairment determination could have a material adverse effect on PHI's financial condition, results of operations and cash flow.

The funding of future defined benefit pension plan and post-retirement benefit plan obligations is based on assumptions regarding the valuation of future benefit obligations and the projected performance of plan assets. If market performance decreases plan assets or changes in assumptions regarding the valuation of benefit obligations increase plan liabilities, any of the Reporting Companies may be required to make significant cash contributions to fund these plans.

PHI holds assets in trust to meet its obligations under PHI's defined benefit pension plan and its post-retirement benefit plan. The amounts that PHI is required to contribute (including the amounts for which Pepco, DPL and ACE are responsible) to fund the trusts are determined based on assumptions made as to the valuation of future benefit obligations, and the projected investment performance of the plan assets. Accordingly, the performance of the capital markets will affect the value of plan assets. A decline in the market value of plan assets as well as a decline in the rate of return on plan assets may increase the plan funding requirements to meet the future benefit obligations. In addition, changes in interest rates affect the valuation of the liabilities of the plans. As interest rates decrease, the present value of the liabilities increase, potentially requiring additional funding. Demographic changes, such as a change in the expected timing of retirements or changes in life expectancy assumptions, also may increase the funding requirements of the plans. A need for significant additional funding of the plans could have a material adverse effect on the cash flows of any of the Reporting Companies. Future increases in pension plan and other post-retirement benefit plan costs, to the extent they are not recoverable in the base rates of PHI's utility subsidiaries, could have a material adverse effect on the results of operations, cash flow and financial condition of any of the Reporting Companies.

Provisions of the Delaware General Corporation Law and in PHI's constituent documents may discourage an acquisition of PHI. (PHI only)

PHI is governed by the provisions of Section 203 of the Delaware General Corporation Law, which prohibit a public Delaware corporation from engaging in a business combination with an interested stockholder (as defined in Section 203) for a period commencing three years from the date in which the person became an interested stockholder, unless:

- the board of directors approved the transaction which resulted in the stockholder becoming an interested stockholder;

- upon consummation of the transaction which resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation (excluding shares owned by officers, directors, or certain employee stock purchase plans); or
- at or subsequent to the time the transaction is approved by the board of directors, there is an affirmative vote of at least 66 2/3% of the outstanding voting stock not owned by the interested stockholder approving the transaction.

Section 203 could prohibit or delay mergers or other takeover attempts against PHI, and accordingly, may discourage or prevent attempts to acquire or control PHI through a tender offer, proxy contest or otherwise.

In addition, PHI's restated certificate of incorporation and amended and restated bylaws contain provisions that may discourage, delay or prevent a third party from acquiring PHI, even if doing so would be beneficial to its stockholders. For example, under PHI's restated certificate of incorporation, only its board of directors may call special meetings of stockholders. Further, stockholder actions may only be taken at a duly called annual or special meeting of stockholders and not by written consent. Moreover, directors of PHI may be removed by stockholders only for cause and only by the effective vote of at least a majority of the outstanding shares of capital stock of PHI entitled to vote generally in the election of directors (voting together as a single class) at a meeting of stockholders called for that purpose. In addition, under PHI's amended and restated bylaws, stockholders must comply with advance notice requirements for nominating candidates for election to PHI's board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings, and this provision may be amended or repealed by stockholders only upon the affirmative vote of the holders of two-thirds of the outstanding shares of PHI capital stock entitled to vote generally in the election of directors, voting together as a single class.

Issuances of additional series of PHI preferred stock could adversely affect holders of PHI's common stock. (PHI only)

PHI's board of directors is authorized to issue shares of PHI preferred stock in series without any action on the part of PHI stockholders. PHI's board of directors also has the power, without stockholder approval, to set the terms of any such series of preferred stock, including with respect to dividend rights, redemption rights and sinking fund provisions, conversion rights, voting rights, and other preferential rights, limitations and restrictions. As of December 31, 2013, there were no shares of PHI preferred stock issued or outstanding.

If PHI issues preferred stock in the future that has a preference over PHI's common stock with respect to the payment of dividends or upon its liquidation, dissolution or winding up, or if preferred stock is issued with voting rights that dilute the voting power of the common stock, the rights of holders of PHI's common stock or the market price of such common stock could be adversely affected. Furthermore, issuances of preferred stock can be used to discourage, delay or prevent a third party from acquiring PHI where the acquisition might be perceived as being beneficial to stockholders.

Because Pepco, DPL and ACE are direct or indirect wholly owned subsidiaries of PHI and have directors and executive officers who are also officers of PHI, PHI can effectively exercise control over their dividend policies and significant business and financial transactions. (Pepco, DPL and ACE only)

All of the members of each of Pepco's, DPL's and ACE's board of directors, as well as many of their respective executive officers, are officers of PHI, and Pepco, DPL and ACE are direct or indirect wholly owned subsidiaries of PHI. Among other decisions, each of Pepco's, DPL's and ACE's board of directors is responsible for decisions regarding payment of dividends, financing and capital raising activities and acquisition and disposition of assets. Within the limitations of applicable law, and subject to the financial covenants under each company's respective outstanding debt instruments, each of Pepco's, DPL's and ACE's board of directors will base its decisions concerning the amount and timing of dividends, and other business decisions, on its capital structure, which is based in part on earnings and cash flow, and also may take into account the business plans and financial requirements of PHI and its other subsidiaries.

Item 1B. UNRESOLVED STAFF COMMENTS

Pepco Holdings

None.

Pepco

None.

DPL

None.

ACE

None.

Item 2. PROPERTIES

Transmission and Distribution Systems

On a combined basis, the electric transmission and distribution systems owned by Pepco, DPL and ACE at December 31, 2013, consisted of approximately 4,000 transmission circuit miles of overhead lines, 600 transmission circuit miles of underground cables, 18,200 distribution circuit miles of overhead lines, and 15,900 distribution circuit miles of underground cables, primarily in their respective service territories. DPL and ACE own and operate distribution system control centers in New Castle, Delaware and Mays Landing, New Jersey, respectively. Pepco also operates a distribution system control center in Bethesda, Maryland. The computer equipment and systems contained in Pepco's control center are financed through a sale and leaseback transaction.

DPL owns a liquefied natural gas facility located in Wilmington, Delaware, with a storage capacity of approximately 3 million gallons and an emergency sendout capability of 25,000 Mcf per day. DPL owns 10 natural gas city gate stations at various locations in New Castle County, Delaware. These stations have a total primary delivery point contractual entitlement of 202,075 Mcf per day. DPL also owns approximately 104 pipeline miles of natural gas transmission mains, 1,836 pipeline miles of natural gas distribution mains, and 1,321 pipeline miles of natural gas service lines. In addition, DPL has a 10% undivided interest in approximately 7 miles of natural gas transmission mains, which are used by DPL for its natural gas operations and by the 90% owner for distribution of natural gas to its electric generating facilities.

Substantially all of the transmission and distribution property, plant and equipment owned by each of Pepco, DPL and ACE is subject to the liens of the respective mortgages under which the companies issue First Mortgage Bonds. See Note (10), "Debt" to the consolidated financial statements of PHI.

Generating Facilities

The following table identifies the electric generating facilities owned by PHI's subsidiaries at December 31, 2013.

Electric Generating Facilities	Location	Owner	Generating Capacity (kilowatts)
Landfill Gas-Fired Units			
Fauquier Landfill Project	Fauquier County, VA	Pepco Energy Services	2,000
Eastern Landfill Project	Baltimore County, MD	Pepco Energy Services	3,000
Bethlehem Landfill Project	Northampton, PA	Pepco Energy Services	5,000
			10,000
Solar Photovoltaic			
Atlantic City Convention Center	Atlantic City, NJ	Pepco Energy Services	2,000
Combined Heat and Power Generating			
Mid Town Plant	Atlantic City, NJ	Pepco Energy Services	5,400
Total Electric Generating Capacity			17,400

The preceding table sets forth the net summer electric generating capacity of each electric generating facility owned. Although the generating capacity may be higher during the winter months, the facilities are used to meet summer peak loads that are generally higher than winter peak loads. Accordingly, the summer generating capacity more accurately reflects the operational capability of the facilities.

Item 3. LEGAL PROCEEDINGS

Pepco Holdings

Other than litigation incidental to PHI and its subsidiaries' business, PHI is not a party to, and PHI 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.

Pepco

Other than 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 (12), "Commitments and Contingencies," to the financial statements of Pepco.

DPL

Other than 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 (14), "Commitments and Contingencies," to the financial statements of DPL.

ACE

Other than 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 (13), "Commitments and Contingencies," to the consolidated financial statements of ACE.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Part II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The New York Stock Exchange is the principal market on which Pepco Holdings common stock is traded. The following table presents the dividends declared per share on the Pepco Holdings common stock and the high and low sales prices for the common stock based on composite trading as reported by the New York Stock Exchange during each quarter in the last two years.

	Dividends Per Share	Price Range High	Price Range Low
2013:			
First Quarter	$ 0.27	$21.43	$18.82
Second Quarter	0.27	22.72	19.35
Third Quarter	0.27	20.90	18.04
Fourth Quarter	0.27	19.62	18.19
	$ 1.08		
2012:			
First Quarter	$ 0.27	$20.48	$18.63
Second Quarter	0.27	19.63	18.14
Third Quarter	0.27	20.30	18.67
Fourth Quarter	0.27	20.06	18.80
	$ 1.08		

At February 14, 2014, there were 46,622 holders of record of Pepco Holdings common stock.

Dividends

On January 23, 2014, the PHI Board of Directors declared a dividend on common stock of 27 cents per share payable March 31, 2014, to shareholders of record on March 10, 2014.

See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Capital Requirements – Dividends," and Note (12), "Stock-Based Compensation, Dividend Restrictions, and Calculations of Earnings Per Share of Common Stock – Dividend Restrictions," of the consolidated financial statements of PHI for information regarding restrictions on the ability of PHI and its subsidiaries to pay dividends.

PHI Subsidiaries

One of PHI's financial objectives is to maintain an equity ratio of 49%-50% in each of its operating utilities. Each quarter, PHI may contribute equity into its utility subsidiaries or the utility subsidiaries may make a dividend payment to PHI in order to maintain an equity ratio of 49%-50% in each of the utility subsidiaries. During 2013, PHI made capital contributions of $175 million and $75 million to Pepco and ACE, respectively, and in 2012, PHI made capital contributions of $50 million and $60 million to Pepco and DPL, respectively.

All of Pepco's common stock is held by Pepco Holdings, and all of DPL's and ACE's common stock is held by Conectiv, LLC (Conectiv), which in turn is wholly owned by Pepco Holdings. The table below presents the aggregate amount of common stock dividends paid by Pepco to PHI, and by DPL and ACE to Conectiv, during each quarter in the last two years. Dividends received by PHI in 2013 and 2012 from Pepco were used to support the payment of its common stock dividend. Dividends paid by ACE and DPL in 2013 and 2012 were used by Conectiv to pay down its short-term debt owed to PHI.

	Pepco	DPL	ACE
2013:			
First Quarter	$ —	$ —	$ —
Second Quarter	15,000,000	20,000,000	—
Third Quarter	31,000,000	10,000,000	25,000,000
Fourth Quarter	—	—	35,000,000
	$46,000,000	$30,000,000	$60,000,000
2012:			
First Quarter	$ —	$ —	$ —
Second Quarter	—	—	15,000,000
Third Quarter	35,000,000	—	20,000,000
Fourth Quarter	—	—	—
	$35,000,000	$ —	$35,000,000

Recent Sales of Unregistered Equity Securities

Pepco Holdings

None.

Pepco

None.

DPL

None.

ACE

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Pepco Holdings

None.

Pepco

None.

DPL

None.

ACE

None.

Item 6. SELECTED FINANCIAL DATA

The following table sets forth selected historical consolidated data for PHI as of and for each of the years ended December 31, 2013, 2012, 2011, 2010, and 2009, derived from PHI's audited consolidated financial statements.

PEPCO HOLDINGS CONSOLIDATED FINANCIAL HIGHLIGHTS

	2013	2012	2011	2010	2009
		(in millions, except per share data)			
Consolidated Operating Results					
Total Operating Revenue	$ 4,666	$ 4,625	$ 4,964	$ 5,407	$ 5,175
Net Income from Continuing Operations	110(a)	218	222	91(b)	163
Net (Loss) Income	(212)	285	257	32	235
Common Stock Information					
Basic Earnings Per Share of Common Stock from Continuing Operations	$ 0.45	$ 0.95	$ 0.98	$ 0.41	$ 0.74
Basic (Loss) Earnings Per Share of Common Stock	(0.86)	1.25	1.14	0.14	1.06
Weighted Average Shares Outstanding—Basic	246	229	226	224	221
Cash Dividends Per Share of Common Stock	1.08	1.08	1.08	1.08	1.08
Year-End Stock Price	19.13	19.61	20.30	18.25	16.85
Net Book Value Per Common Share (c)	17.23	19.19	18.92	18.65	19.00
Other Information					
Total Assets	14,848	15,794	15,001	14,654	16,074
Capitalization					
Short-term Debt	$ 565	$ 965	$ 732	$ 534	$ 530
Long-term Debt	4,053	3,648	3,794	3,629	4,470
Current Portion of Long-Term Debt and Project Funding	446	569	112	75	536
Transition Bonds issued by ACE Funding	214	256	295	332	368
Capital Lease Obligations due within one year	9	8	8	8	7
Capital Lease Obligations	60	70	78	86	92
Long-Term Project Funding	10	12	13	15	17
Non-controlling Interest	—	—	—	6	6
Common Shareholders' Equity (c)	4,315	4,414	4,304	4,198	4,224
Total Capitalization (c)	$ 9,672	$ 9,942	$ 9,336	$ 8,883	$10,250

(a) Includes a charge of $101 million to establish valuation allowances related to certain PCI deferred tax assets and a charge of $66 million to reflect the anticipated additional interest expense on estimated federal and state income tax obligations resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments.

(b) Includes a loss on extinguishment of debt of $189 million ($113 million after-tax).

(c) Amounts for net book value per common share, common shareholders' equity and total capitalization for 2009 to 2012 have been adjusted for a revision to prior period financial statements related to deferred income tax liabilities for PCI that reduced equity by $32 million, as shown below. Amounts for total equity as filed and as revised below exclude non-controlling interests of $6 million as of December 31, 2010 and 2009.

	Total Equity As Filed	Adjustment	Total Equity As Revised
		(millions of dollars)	
December 31, 2012	$ 4,446	$ (32)	$ 4,414
December 31, 2011	$ 4,336	$ (32)	$ 4,304
December 31, 2010	$ 4,230	$ (32)	$ 4,198
December 31, 2009	$ 4,256	$ (32)	$ 4,224

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL, AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND THEREFORE ARE FILING THIS FORM WITH THE REDUCED FILING FORMAT.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

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

Pepco Holdings, Inc.

General Overview

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

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

The following table sets forth the percentage contributions to consolidated operating revenue and operating income from continuing operations attributable to PHI segments for each of the preceding three years:

	2013	2012	2011
Percentage of Consolidated Operating Revenue			
Power Delivery	96%	95%	94%
Pepco Energy Services	4%	6%	7%
Corporate and Other	—	(1)%	(1)%
Percentage of Consolidated Operating Income			
Power Delivery	97%	98%	90%
Pepco Energy Services	—	(3)%	5%
Corporate and Other	3%	5%	5%
Percentage of Consolidated Operating Revenue—Power Delivery			
Power Delivery Electric	96%	96%	95%
Power Delivery Gas	4%	4%	5%

Power Delivery

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

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

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

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

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

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

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

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

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

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

PHI's capital expenditures for continuing reliability enhancement efforts are included in the table of projected capital expenditures within "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Capital Requirements – Capital Expenditures."

Power Delivery Initiatives and Activities

Smart Grid Initiatives

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

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

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

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

- Pepco was awarded $149 million for AMI, direct load control, distribution automation and communications infrastructure, of which $145 has been received through December 31, 2013.
- ACE was awarded $19 million for direct load control, distribution automation and communications infrastructure, of which $17 has been received through December 31, 2013.

For a discussion of the projected capital expenditures of each utility subsidiary associated with PHI's smart grid initiatives over the period 2014 through 2018, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Capital Requirements."

Mitigation of Regulatory Lag

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

In an effort to minimize the effects of regulatory lag, PHI's utility subsidiaries are:

- filing electric distribution base rate cases every nine to twelve months in each of their jurisdictions,
- pursuing alternative ratemaking mechanisms,
- evaluating potential reductions in planned capital expenditures, and
- continuing outreach to the regulatory community and other stakeholders, to discuss the changing regulatory model economics that are causing regulatory lag.

Alternative mechanisms that may reduce regulatory lag include adjusting historic test periods in distribution base rate cases to recognize plant additions which are already being used to provide service to customers when new rates go into effect, grid resiliency charges to allow contemporaneous recovery of costs for infrastructure related to system reliability, and multi-year rate plans.

Each of PHI's utility subsidiaries will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag and have an opportunity to earn its authorized ROE. There can be no assurance that any attempts by PHI's utility subsidiaries to mitigate regulatory lag will be approved or, that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct MAPP, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, PHI submitted a filing to FERC seeking recovery of $88 million of abandoned MAPP costs over a five-year period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

In December 2013, PHI submitted a settlement agreement to FERC with respect to this matter. Under the terms of the proposed settlement agreement, Pepco and DPL would recover their abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. The terms of this settlement, if approved, would not be subject to the pending formula rate or transmission ROE challenges at FERC or modification through any other FERC proceeding. PHI cannot predict the timing or results of a final FERC decision in this proceeding.

As of December 31, 2013, PHI had a regulatory asset related to the MAPP abandoned costs of approximately $68 million, representing the original filing amount of approximately $88 million of abandoned costs referred to above less: (i) approximately $2 million of disallowed costs written off in

2013; (ii) $4 million of materials transferred to inventories for use on other projects; and (iii) $14 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, DPL and ACE, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. PHI, Pepco, DPL and ACE believe the allegations in this complaint are without merit and are vigorously contesting it. On April 3, 2013, Pepco, DPL and ACE filed their answer to this complaint, requesting that FERC dismiss the complaint against them on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. PHI cannot predict when a final FERC decision in this proceeding will be issued.

Pepco Energy Services

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

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At December 31, 2013, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $190 million.

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. Pepco Energy Services placed the facilities into an idle condition termed a "cold closure." A cold closure requires that the utility service be disconnected so that the facilities are no longer operable and require only essential maintenance until they are completely decommissioned. During the third quarter of 2013, Pepco Energy Services determined that it would be more cost effective to pursue the demolition of the Benning Road generation facility and realization of the scrap metal salvage value of the facility instead of maintaining cold closure status. The demolition of the facility commenced in the fourth quarter of 2013 and is expected to be completed by the end of 2014. Pepco Energy Services will recognize the salvage proceeds associated with the scrap metals at the facility as realized.

Corporate and Other

Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to both Consolidated Edison's cross-border lease transaction (discussed in "– Discontinued Operations – Cross-Border Energy Lease Investments" below) and another taxpayer's structured transactions, (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI would be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of all relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances. This charge is included in Corporate and Other, as presented in Note (5), "Segment Information," to the consolidated financial statements of PHI, because the remaining operations of the former Other Non-Regulated segment are now included in Corporate and Other.

Discontinued Operations

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

Cross-Border Energy Lease Investments

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

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

- A non-cash pre-tax charge of $373 million ($313 million after-tax) to reduce the carrying value of these cross-border energy lease investments under FASB guidance on leases (Accounting Standards Codification (ASC) 840). This pre-tax charge was originally recorded in the consolidated statements of (loss) income as a reduction in operating revenue and is now reflected in (loss) income from discontinued operations, net of income taxes.
- A non-cash charge of $16 million after-tax to reflect the anticipated additional net interest expense under FASB guidance for income taxes (ASC 740), related to estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed. This after-tax charge was originally recorded in the consolidated statements of (loss) income as an increase

in income tax expense and is now reflected in (loss) income from discontinued operations, net of income taxes. The after-tax interest charge for PHI on a consolidated basis was $70 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in the recognition of a $12 million interest benefit for the Power Delivery segment and interest expense of $16 million for PCI and $66 million for Corporate and Other, respectively.

Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services

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

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

Earnings Overview

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	2013	2012	Change
	(millions of dollars)		
Power Delivery	$ 289	$235	$ 54
Pepco Energy Services	3	(8)	11
Corporate and Other	(182)	(9)	(173)
Net Income from Continuing Operations	110	218	(108)
Discontinued Operations	(322)	67	(389)
Total PHI Net (Loss) Income	$(212)	$285	$ (497)

Net income from continuing operations for the year ended December 31, 2013 was $110 million, or $0.45 per share, compared to $218 million, or $0.95 per share, for the year ended December 31, 2012.

Net income from continuing operations for the year ended December 31, 2013 included the charges set forth below in Corporate and Other, which are presented, where applicable, net of related federal and state income taxes and are in millions of dollars:

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

Excluding the items listed above for the year ended December 31, 2013, net income from continuing operations would have been $277 million, or $1.13 per share. PHI discloses net income from continuing operations and related per share data excluding these items because management believes that these items are not representative of PHI's ongoing business operations. Management uses this information, and believes that such information is useful to investors, in evaluating PHI's period-over-period performance. The inclusion of this disclosure is intended to complement, and should not be considered as an alternative to, PHI's reported net income from continuing operations and related per share data in accordance with GAAP.

Net loss from discontinued operations for the year ended December 31, 2013 was $322 million, or $1.31 per share, compared to net income of $67 million, or $0.30 per share ($0.29 per share on a diluted basis), for the year ended December 31, 2012.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $54 million increase in earnings was primarily due to the following:

- An increase of $64 million from electric distribution base rate increases (Pepco in the District of Columbia and Maryland, DPL in Maryland and Delaware and ACE in New Jersey).
- An increase of $16 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012, partially offset by recovery in 2012 of 2011 storm restoration costs and regulatory expenses.
- An increase of $4 million primarily due to higher sales from colder winter weather, partially offset by lower sales from milder summer weather.
- A decrease of $12 million due to higher depreciation and amortization expense associated primarily with regulatory assets and increases in plant investment, partially offset by lower depreciation rates.
- A decrease of $7 million due to higher interest expense resulting from an increase in outstanding debt.
- A decrease of $6 million associated with Default Electricity Supply margins for DPL Delaware, primarily due to favorable adjustments in 2012 related to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes.

Pepco Energy Services' $11 million increase in earnings was primarily due to the following:

- An increase of $6 million primarily due to improved performance in the energy savings business and thermal business in Atlantic City, New Jersey, as well as lower compensation expenses.
- An increase of $5 million due to lower asset impairment charges.

Corporate and Other's $173 million increase in net loss was primarily due to the following:

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

Discussion of Discontinued Operations Variance:

Net earnings from discontinued operations for the year ended December 31, 2013 decreased by $389 million as a result of the following:

- An aggregate after-tax charge of $313 million recorded in 2013 to reduce the carrying value of PCI's cross-border energy lease investments ($373 million pre-tax).
- An after-tax charge of $16 million recorded in 2013 to reflect the anticipated additional interest expense on estimated federal and state income tax obligations allocated to PCI (as if it were a separate taxpayer) resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments ($25 million pre-tax).
- An after-tax gain of $9 million recorded in 2012 related to the early termination of certain cross-border energy leases ($39 million pre-tax) and an after-tax loss of $2 million recorded in 2013 ($3 million pre-tax), associated with the completion of the early termination of the remaining cross-border energy lease investments.
- A decrease of $27 million as a result of holding fewer cross-border energy leases in 2013.
- A decrease of $21 million as a result of lower sales volume in 2013 due to the wind-down of the retail electric and natural gas supply businesses.

Consolidated Results of Operations

The following results of operations discussion compares the year ended December 31, 2013 to the year ended December 31, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Continuing Operations

Operating Revenue

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

	2013	2012	Change
Power Delivery	$4,472	$4,378	$ 94
Pepco Energy Services	203	256	(53)
Corporate and Other	(9)	(9)	—
Total Operating Revenue	$4,666	$4,625	$ 41

Power Delivery

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

	2013	2012	Change
Regulated T&D Electric Revenue	$2,146	$2,006	$ 140
Default Electricity Supply Revenue	2,075	2,124	(49)
Other Electric Revenue	60	65	(5)
Total Electric Operating Revenue	4,281	4,195	86
Regulated Gas Revenue	165	151	14
Other Gas Revenue	26	32	(6)
Total Gas Operating Revenue	191	183	8
Total Power Delivery Operating Revenue	$4,472	$4,378	$ 94

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 that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, and revenue in the form of transmission enhancement credits that PHI utility subsidiaries receive as transmission owners from PJM in consideration for approved regional transmission expansion plan expenditures.

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

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

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

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 781	$ 722	$ 59
Commercial and industrial	970	923	47
Transmission and other	395	361	34
Total Regulated T&D Electric Revenue	$ 2,146	$ 2,006	$ 140

	2013	2012	Change
Regulated T&D Electric Sales (Gigawatt hour (GWh))			
Residential	17,168	17,150	18
Commercial and industrial	30,070	30,734	(664)
Transmission and other	259	258	1
Total Regulated T&D Electric Sales	47,497	48,142	(645)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,650	1,641	9
Commercial and industrial	200	198	2
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,852	1,841	11

Regulated T&D Electric Revenue increased by $140 million primarily due to:

- An increase of $107 million due to distribution rate increases (Pepco in the District of Columbia effective October 2012, and in Maryland effective July 2013 and July 2012; DPL in Maryland effective July 2012 and September 2013, and in Delaware effective October 2013 and July 2012; ACE effective November 2012 and July 2013).
- An increase of $14 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $14 million in transmission revenue rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $7 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset in Purchased Energy and Depreciation and Amortization).
- An increase of $6 million primarily due to a rate increase in the New Jersey Societal Benefit Charge (related to the New Jersey Societal Benefit Program, which is a New Jersey public interest program for low income customers) effective July 2012 (which is offset in Deferred Electric Service Costs).
- An increase of $6 million in transmission revenue primarily attributable to higher capacity as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).
- An increase of $5 million primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset in Fuel and Purchased Energy and Depreciation and Amortization).
- An increase of $3 million due to Pepco and DPL customer growth in 2013, primarily in the residential class.

The aggregate amount of these increases was partially offset by:

- A decrease of $13 million due to lower non-weather related average residential and commercial customer usage.
- A decrease of $6 million in transmission revenue associated with the change in FERC formula rate true-ups.
- A decrease of $4 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a decrease in utility taxes collected by Pepco on behalf of Montgomery County, Maryland.
- A decrease of $1 million in transmission revenue primarily attributable to a peak-load rate decrease effective January 2013.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$1,376	$1,467	$ (91)
Commercial and industrial	542	542	—
Other	157	115	42
Total Default Electricity Supply Revenue	$2,075	$2,124	$ (49)

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 non-utility generators (NUGs), and (ii) revenue from transmission enhancement credits.

	2013	2012	Change
Default Electricity Supply Sales (Gigawatt hours (GWh))			
Residential	13,743	14,245	(502)
Commercial and industrial	5,079	5,508	(429)
Other	55	55	—
Total Default Electricity Supply Sales	18,877	19,808	(931)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,352	1,366	(14)
Commercial and industrial	125	128	(3)
Other	—	1	(1)
Total Default Electricity Supply Customers	1,477	1,495	(18)

Default Electricity Supply Revenue decreased by $49 million primarily due to:

- A decrease of $76 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $22 million due to lower ACE and DPL non-weather related average customer usage.

The aggregate amount of these decreases was partially offset by:

- An increase of $36 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.
- An increase of $6 million due to higher Pepco and DPL revenue from transmission enhancement credits.
- An increase of $4 million due to higher sales primarily as a result of colder weather during the 2013 fall months, as compared to 2012.
- A net increase of $2 million as a result of higher Pepco Default Electricity Supply rates, partially offset by lower DPL and ACE rates.

Regulated Gas

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 103	$ 94	$ 9
Commercial and industrial	52	47	5
Transportation and other	10	10	—
Total Regulated Gas Revenue	$ 165	$ 151	$ 14

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	7,861	6,428	1,433
Commercial and industrial	4,945	3,636	1,309
Transportation and other	6,990	6,751	239
Total Regulated Gas Sales	19,796	16,815	2,981

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	117	115	2
Commercial and industrial	9	10	(1)
Transportation and other	—	—	—
Total Regulated Gas Customers	126	125	1

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, government, insurance, shopping malls, casinos and tourism.
- Industrial activities in the region include chemical, pharmaceutical, steel manufacturing and oil refining.

Regulated Gas Revenue increased by $14 million primarily due to:

- An increase of $22 million due to higher sales primarily as a result of colder weather during the winter months of 2013 as compared to 2012.
- An increase of $7 million due to higher non-weather related average commercial customer usage.
- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by an increase in Purchased Energy).
- An increase of $2 million due to a distribution rate increase effective July 2013.

The aggregate amount of these increases was partially offset by a decrease of $22 million due to a Gas Cost Rate (GCR) decrease effective November 2012.

Other Gas Revenue

Other Gas Revenue decreased by $6 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 $53 million primarily due to:

- A decrease of $36 million primarily in energy savings construction activities.
- A decrease of $18 million associated with the retirement of the two remaining oil-fired generation facilities in the second quarter of 2012.

Operating Expenses

Fuel and Purchased Energy and Other Services Cost of Sales

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

	2013	2012	Change
Power Delivery	$2,070	$2,109	$ (39)
Pepco Energy Services	148	186	(38)
Corporate and Other	(2)	(2)	—
Total	$2,216	$2,293	$ (77)

Power Delivery

Power Delivery's Fuel and Purchased Energy consists of the cost of electricity and natural gas purchased by its utility subsidiaries to fulfill their respective Default Electricity Supply and Regulated Gas obligations and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of natural gas purchased for off-system sales. Fuel and Purchased Energy expense decreased by $39 million primarily due to:

- A decrease of $85 million primarily due to customer migration to competitive suppliers.
- A decrease of $20 million in deferred electricity expense primarily due to higher DPL Default Electricity Supply cost of service rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $13 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 $5 million in the cost of gas purchases for off-system sales as a result of lower volumes.

The aggregate amount of these decreases was partially offset by:

- A net increase of $45 million due to higher average electricity costs under Pepco and DPL Default Electricity Supply contracts, partially offset by lower ACE costs.
- An increase of $13 million in deferred electricity expense primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset in Regulated T&D Electric Revenue and Depreciation and Amortization).
- An increase of $11 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.

- An increase of $6 million due to higher electricity sales primarily as a result of colder weather during the 2013 fall months, as compared to 2012.
- An increase of $4 million in the costs associated with purchasing Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).
- An increase of $2 million in the costs associated with purchases under wind power purchase agreements in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales decreased by $38 million primarily due to:

- A decrease of $30 million primarily due to lower energy savings construction activity.
- A decrease of $7 million due to lower purchases of capacity and lower fuel usage, both attributable to the retirement of the remaining oil-fired generation facilities in the second quarter of 2012.

Other Operation and Maintenance

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

	2013	2012	Change
Power Delivery	$871	$901	$ (30)
Pepco Energy Services	42	58	(16)
Corporate and Other	(62)	(61)	(1)
Total	$851	$898	$ (47)

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $30 million primarily due to:

- A decrease of $16 million in storm restoration costs.
- A decrease of $15 million associated with lower maintenance costs.
- A decrease of $9 million in customer service costs.
- A decrease of $1 million primarily due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	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	—	(34)	34
Costs associated with Hurricane Sandy (October 2012)	—	28	(28)
Regulatory assets established for future recovery of Hurricane Sandy costs	—	(22)	22
Total incremental major storm restoration costs	$ —	$ 1	$ (1)

- 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 over a five-year period.
- During 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 $34 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 2013 and August 2013 rate orders, respectively, over a five-year period. ACE's stipulation of settlement approved by the NJBPU in June 2013 provides for recovery of these costs in New Jersey over a three-year period. The remaining costs of $4 million relate to repair work completed in Delaware and the District of Columbia which are not deferrable in those jurisdictions.
- In the fourth quarter of 2012, Pepco, DPL and ACE incurred incremental storm restoration costs of $28 million associated with Hurricane Sandy which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $22 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 2013 and August 2013 rate orders, respectively, over a five-year period. ACE's stipulation of settlement approved by the NJBPU in June 2013 provides for recovery of these costs in New Jersey over a three-year period. The remaining costs of $6 million relate to repair work completed in Delaware and the District of Columbia which are not deferrable in those jurisdictions.

The aggregate amount of these decreases was partially offset by:

- An increase of $6 million resulting from a 2012 deferred cost adjustment associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes.

- An increase of $3 million associated with the write-off of disallowed MAPP and associated transmission projects costs.
- An increase of $3 million in environmental remediation costs.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $16 million primarily due to:

- A decrease of $5 million in personnel costs in its energy savings business primarily due to a reduction in the number of employees in the second half of 2012.
- A decrease of $4 million in contractual costs associated with the retirement of the two remaining oil-fired generation facilities in the second quarter of 2012.
- A decrease of $3 million in bid and proposal costs in its energy savings business.
- A decrease of $1 million associated with an accrual for an energy savings guarantee shortfall in 2012.
- A decrease of $1 million in operating, repairs and maintenance expenses at its combined heat and power thermal operations in Atlantic City.

Depreciation and Amortization

Depreciation and Amortization expense increased by $19 million to $473 million in 2013 from $454 million in 2012 primarily due to:

- An increase of $14 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.
- An increase of $14 million in amortization of MAPP abandonment costs (which is offset in T&D Electric Revenue).
- An increase of $6 million in amortization due to the expiration in August 2013 of the excess depreciation reserve regulatory liability of ACE.

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million due to the deactivation of Pepco Energy Services' oil-fired generating facilities in the second quarter of 2012 and a reduction in the Benning Road asset retirement obligation in 2013 resulting from the decision to pursue the demolition of the Benning Road oil-fired generating facility.
- A decrease of $7 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Fuel and Purchased Energy).

Power Delivery depreciation reflected no change from 2012 due to an increase from higher plant investment offset by lower depreciation rates in Pepco and DPL, approved by the MPSC effective July 20, 2012.

Other Taxes

Other Taxes decreased by $4 million to $428 million in 2013 from $432 million in 2012. The decrease was primarily due to lower sales that resulted in a decrease in utility taxes that are collected and passed through by Power Delivery (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Deferred Electric Service Costs

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

Deferred Electric Service Costs increased by $31 million to an expense of $26 million in 2013 as compared to an expense reduction of $5 million in 2012 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Program revenue rates and lower electricity supply costs.

Impairment Losses

Impairment losses decreased by $8 million to $4 million in 2013 from $12 million in 2012. The decrease was primarily due to 2012 impairment losses of $12 million ($7 million after-tax) at Pepco Energy Services associated with the combustion turbines at Buzzard Point and certain landfill gas-fired electric generation facilities, partially offset by a 2013 impairment loss of $4 million ($3 million after-tax) associated with a landfill gas-fired electric generation facility.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $19 million to a net expense of $239 million in 2013 from a net expense of $220 million in 2012. The increase reflects a $16 million increase in interest expense primarily associated with higher long-term debt and $3 million associated with lower income related to the allowance for funds used during construction (AFUDC) that is applied to capital projects.

Income Tax Expense

PHI's income tax expense increased by $216 million to $319 million in 2013 from $103 million in 2012.

PHI's consolidated effective income tax rates for the years ended December 31, 2013 and 2012 were 74.4% and 32.1%, respectively.

The increase in the effective tax rate for the year ended December 31, 2013 occurred as a result of recording $56 million of changes in estimates and interest related to uncertain and effectively settled tax positions in the first quarter of 2013. In addition, the increase in the effective tax rate resulted from the establishment of valuation allowances of $101 million in the first quarter of 2013 against certain deferred tax assets in PCI, which is now included in Corporate and Other. Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to both Consolidated Edison's cross-border lease transaction (as discussed in Note (19), "Discontinued Operations – Cross-Border Energy Lease Investments," to the consolidated financial statements of PHI) and another taxpayer's structured transactions, (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI would be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of the relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances.

The effective income tax rate for the year ended December 31, 2012 includes income tax benefits of $8 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.

The rate for the year ended December 31, 2012 also reflects an increase in deductible asset removal costs for Pepco in 2012 related to a higher level of asset retirements.

Discontinued Operations

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

	2013	2012	Change
Cross-border energy lease investments	$(327)	$41	$ (368)
Pepco Energy Services' retail electric and natural gas supply businesses	5	26	(21)
(Loss) income from discontinued operations, net of income taxes	$(322)	$67	$ (389)

For the years ended December 31, 2013 and 2012, (loss) income from discontinued operations, net of income taxes, was a loss of $322 million and income of $67 million, respectively. The decrease of $389 million is comprised of a decrease of $368 million related to PHI's cross-border lease investments and a decrease of $21 million related to the retail electric and natural gas supply businesses at Pepco Energy Services.

The decrease in (loss) income from discontinued operations, net of income taxes, for PHI's cross-border energy lease investments is primarily due to after-tax non-cash charges of $323 million recorded in the first quarter of 2013 and $6 million in the second quarter of 2013, each related to a change in assessment regarding the tax benefits related to the cross-border energy lease investments and consisting of a $373 million pre-tax non-cash charge ($313 million after-tax) to reduce the carrying value of the investments and a $16 million after-tax non-cash charge to reflect the anticipated additional interest expense related to the change in PCI's estimated federal and state income tax obligations as if it were a separate taxpayer. The (loss) income from discontinued operations, net of income taxes, was reduced further by lower cross-border energy lease investment earnings as a result of terminating the cross-border lease investments in 2013, the loss recorded on the early termination of the remaining cross-border energy lease investments during 2013, and gains recorded on the early termination of certain leases within the cross-border energy lease portfolio in the third quarter of 2012.

The decrease in (loss) income from discontinued operations, net of income taxes, at Pepco Energy Services is due to a reduction in sales volume associated with the wind-down of the retail electric and natural gas supply businesses, a reduction in mark-to-market gains, and costs incurred to accelerate the wind-down of the retail electric supply business.

The following results of operations discussion compares the year ended December 31, 2012 to the year ended December 31, 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	$4,378	$4,650	$ (272)
Pepco Energy Services	256	330	(74)
Corporate and Other	(9)	(16)	7
Total Operating Revenue	$4,625	$4,964	$ (339)

Power Delivery

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

	2012	2011	Change
Regulated T&D Electric Revenue	$2,006	$1,891	$ 115
Default Electricity Supply Revenue	2,124	2,462	(338)
Other Electric Revenue	65	67	(2)
Total Electric Operating Revenue	4,195	4,420	(225)
Regulated Gas Revenue	151	183	(32)
Other Gas Revenue	32	47	(15)
Total Gas Operating Revenue	183	230	(47)
Total Power Delivery Operating Revenue	$4,378	$4,650	$ (272)

Regulated 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 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 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	$ 722	$ 683	$ 39
Commercial and industrial	923	884	39
Transmission and other	361	324	37
Total Regulated T&D Electric Revenue	$ 2,006	$ 1,891	$ 115

	2012	2011	Change
Regulated T&D Electric Sales (GWh)			
Residential	17,150	17,728	(578)
Commercial and industrial	30,734	31,282	(548)
Transmission and other	258	256	2
Total Regulated T&D Electric Sales	48,142	49,266	(1,124)

	2012	2011	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,641	1,636	5
Commercial and industrial	198	198	—
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,841	1,836	5

Regulated T&D Electric Revenue increased by $115 million primarily due to:

- An increase of $46 million due to distribution rate increases in all jurisdictions (Pepco in the District of Columbia effective October 2012, and in Maryland effective July 2012; DPL in Maryland effective July 2012 and July 2011, and in Delaware effective July 2012; ACE effective November 2012).
- An increase of $35 million in transmission revenue primarily attributable to higher Pepco and DPL rates effective June 1, 2012 and June 1, 2011 related to increases in transmission plant investment and operating expenses.
- An increase of $17 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 $15 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 $15 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).
- An increase of $7 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 $13 million due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.
- A decrease of $6 million in Transitional Energy Facility Assessment (TEFA) rate revenue in New Jersey due to a rate decrease effective January 2012 (which is primarily offset by a corresponding decrease in Other Taxes).

Default Electricity Supply

	2012	2011	Change
Default Electricity Supply Revenue			
Residential	$1,467	$1,668	$ (201)
Commercial and industrial	542	642	(100)
Other	115	152	(37)
Total Default Electricity Supply Revenue	$2,124	$2,462	$ (338)

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	14,245	15,545	(1,300)
Commercial and industrial	5,508	6,168	(660)
Other	55	73	(18)
Total Default Electricity Supply Sales	19,808	21,786	(1,978)

	2012	2011	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,366	1,432	(66)
Commercial and industrial	128	137	(9)
Other	1	—	1
Total Default Electricity Supply Customers	1,495	1,569	(74)

Default Electricity Supply Revenue decreased by $338 million primarily due to:

- A decrease of $140 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A net decrease of $100 million as a result of lower Pepco and DPL Default Electricity Supply rates, partially offset by higher ACE rates.
- A decrease of $38 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 $35 million due to lower sales as a result of milder weather during the 2012 winter and spring months, as compared to 2011.
- A net decrease of $26 million due to lower Pepco and ACE non-weather related average residential customer usage, partially offset by higher DPL residential customer usage.

The aggregate amount of these decreases was partially offset by an increase of $5 million due to higher Pepco revenue from transmission enhancement credits.

Regulated Gas

	2012	2011	Change
Regulated Gas Revenue			
Residential	$ 94	$ 113	$ (19)
Commercial and industrial	47	61	(14)
Transportation and other	10	9	1
Total Regulated Gas Revenue	$ 151	$ 183	$ (32)

	2012	2011	Change
Regulated Gas Sales (million cubic feet)			
Residential	6,428	7,346	(918)
Commercial and industrial	3,636	4,442	(806)
Transportation and other	6,751	6,966	(215)
Total Regulated Gas Sales	16,815	18,754	(1,939)

	2012	2011	Change
Regulated Gas Customers (in thousands)			
Residential	115	115	—
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	125	124	1

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

- A decrease of $14 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 $9 million due to GCR decreases effective November 2011 and November 2012.
- A decrease of $5 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 offset by a decrease in Fuel and Purchased Energy).

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 $15 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 $74 million primarily due to:

- A decrease of $55 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 $19 million primarily due to decreased energy savings construction activities.

Operating Expenses

Fuel and Purchased Energy and Other Services Cost of Sales

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

	2012	2011	Change
Power Delivery	$2,109	$2,490	$ (381)
Pepco Energy Services	186	221	(35)
Corporate and Other	(2)	(2)	—
Total	$2,293	$2,709	$ (416)

Power Delivery

Power Delivery's Fuel and Purchased Energy consists of the cost of electricity and natural gas purchased by its utility subsidiaries to fulfill their respective Default Electricity Supply and Regulated Gas obligations and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of natural gas purchased for off-system sales. Fuel and Purchased Energy expense decreased by $381 million primarily due to:

- A decrease of $158 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $142 million primarily due to customer migration to competitive suppliers.
- A decrease of $29 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 $18 million in deferred electricity expense primarily due to lower Pepco and DPL Default Electricity Supply revenue rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $12 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 $11 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 $6 million in deferred gas expense as a result of a higher rate of recovery of natural gas supply costs due to lower average gas prices.
- An increase of $6 million in costs to purchase Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales decreased by $35 million primarily due to:

- A decrease of $29 million due to lower purchases of capacity and lower fuel usage, both attributable to the retirement of the remaining generation facilities in the second quarter of 2012.
- A decrease of $7 million due to lower energy savings construction activity partially offset by higher costs associated with energy services and underground transmission construction activities.

Other Operation and Maintenance

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

	2012	2011	Change
Power Delivery	$ 901	$ 884	$ 17
Pepco Energy Services	58	62	(4)
Corporate and Other	(61)	(57)	(4)
Total	$ 898	$ 889	$ 9

Power Delivery

Other Operation and Maintenance expense for Power Delivery increased by $17 million primarily due to:

- An increase of $16 million in employee-related costs, primarily pension and other employee benefits.
- An increase of $10 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 and administrative costs in 2011, partially offset by favorable adjustments in 2012 related to allowed returns on net uncollectible expense and recovery of regulatory taxes.
- An increase of $8 million in customer support service and system support costs.
- An increase of $5 million in New Jersey Societal Benefit Program costs that are deferred and recoverable.
- An increase of $4 million in expenses related to regulatory filings.
- An increase of $4 million in self-insurance reserves for general and auto liability claims.

The aggregate amount of these increases was partially offset by:

- A decrease of $15 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)	38	—	38
Regulatory asset established for future recovery of derecho storm costs	(34)	—	(34)
Costs associated with Hurricane Sandy (October 2012)	28	—	28
Regulatory asset established for future recovery of Hurricane Sandy costs	(22)	—	(22)
Costs associated with Hurricane Irene (August 2011)	—	28	(28)
Regulatory asset established for future recovery of Hurricane Irene costs	—	(22)	22
Total incremental major storm restoration costs	$ 1	$ 16	$ (15)

  - 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 over a five-year period.
  - During 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 $34 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 in their electric distribution base rate cases. The remaining costs of $4 million primarily relate to repair work completed in Delaware and the District of Columbia which are not deferrable in those jurisdictions.
  - In the fourth quarter of 2012, Pepco, DPL and ACE incurred incremental storm restoration costs of $28 million associated with Hurricane Sandy which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $22 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 in their electric distribution base rate cases. The remaining costs of $6 million primarily relate to repair work completed in Delaware and the District of Columbia which are not deferrable in those jurisdictions.
  - During 2011, Pepco, DPL and ACE incurred incremental storm restoration costs of $28 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 $22 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 over a five-year period. ACE's stipulation of settlement approved by the NJBPU in October 2012 provides for recovery of these costs in New Jersey over a three-year period. The remaining costs of $6 million relate to repair work completed in Delaware and the District of Columbia which are not deferrable in those jurisdictions.
- A decrease of $8 million in bad debt expenses.
- A decrease of $4 million associated with lower preventative 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 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 $4 million primarily due to the closing of the oil-fired generation facilities in the second quarter of 2012, partially offset by higher energy services expenses.

Depreciation and Amortization

Depreciation and Amortization expense increased by $29 million to $454 million in 2012 from $425 million in 2011 primarily due to:

- An increase of $22 million in amortization of regulatory assets primarily due to EmPower Maryland surcharge rate increases effective February 2012 and expanding Demand Side Management Programs (which are substantially offset by corresponding increases in Regulated T&D Electric Revenue).
- An increase of $11 million in amortization of AMI projects.
- An increase of $5 million due to utility plant additions, partially offset by lower depreciation rates.
- 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 $12 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 (revenue ACE receives and pays to ACE Funding to recover income taxes associated with Transition Bond Charge revenue) (partially offset in Default Electricity Supply Revenue).
- A decrease of $4 million primarily due to the deactivation of Pepco Energy Services generating facilities in May 2012.

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 $19 million to $432 million in 2012 from $451 million in 2011. The decrease was primarily due to:

- A decrease of $10 million, primarily due to 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 $5 million in TEFA tax collections 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, 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 $58 million, to an expense reduction of $5 million in 2012 as compared to an expense reduction of $63 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 year ended December 31, 2012, included impairment losses of $12 million ($7 million after-tax) at Pepco Energy Services associated with the combustion turbines at Buzzard Point and certain landfill gas-fired electric generation facilities.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $3 million to a net expense of $220 million in 2012 from a net expense of $217 million in 2011. The increase reflects a $14 million increase in interest expense primarily associated with higher long-term debt and lower capitalized interest. The increase was mostly offset by an increase of $10 million in other income primarily from losses and impairments on equity investments in 2011 that did not occur in 2012.

Income Tax Expense

PHI's income tax expense decreased by $11 million to $103 million in 2012 from $114 million in 2011.

PHI's consolidated effective income tax rates for the years ended December 31, 2012 and 2011 were 32.1% and 33.9%, respectively.

The effective income tax rate for the year ended December 31, 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 year ended December 31, 2011, PHI recorded tax benefits of $17 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 year ended December 31, 2012 also reflects an increase in deductible asset removal costs for Pepco in 2012 related to a higher level of asset retirements.

Discontinued Operations

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

	2012	2011	Change
Cross-border energy lease investments	$ 41	$36	$ 5
Pepco Energy Services' retail electric and natural gas supply businesses	26	2	24
Conectiv Energy	—	(3)	3
Income from discontinued operations, net of income taxes	$ 67	$35	$ 32

Income from discontinued operations, net of income taxes, increased by $32 million to $67 million in 2012 from $35 million in 2011.

The increase of $5 million in income from discontinued operations, net of income taxes, attributable to PHI's cross-border energy lease investments was primarily due to higher gains recorded on the early termination of certain leases within the cross-border energy lease portfolio in 2012 as compared to 2011. The pre-tax gains were $39 million for each of the years ended December 31, 2012 and 2011, and the after-tax gains were $9 million and $3 million for the years ended December 31, 2012 and 2011, respectively.

The increase of $24 million in income from discontinued operations, net of income taxes, attributable to Pepco Energy Services' retail electric and natural gas supply businesses was primarily due to higher gross margins related to gains from mark-to-market accounting for derivatives used to manage commodity price risk and decreases in other operation and maintenance expenses. These increases were partially offset by reduced sales volumes associated with the ongoing wind-down of the retail electric and natural gas supply businesses.

The loss from discontinued operations, net of income taxes, for Conectiv Energy in 2011 resulted from the recognition of a loss related to the disposition of the remaining assets and businesses of Conectiv Energy not included in the sale of such assets and businesses to Calpine Corporation.

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 December 31, 2013, PHI's current assets on a consolidated basis totaled $1.4 billion and its consolidated current liabilities totaled $2.3 billion, resulting in a working capital deficit of $0.9 billion. PHI expects the working capital deficit at December 31, 2013 to be funded during 2014 in part through cash flows from operations and from the issuance of long-term debt. At December 31, 2012, PHI's current assets on a consolidated basis totaled $1.3 billion and its consolidated current liabilities totaled $2.5 billion, for a working capital deficit of $1.2 billion. The decrease of $361 million in the working capital deficit from December 31, 2012 to December 31, 2013 was primarily due to a decrease in short-term debt, the repayment of which was primarily funded with cash received from the early terminations of the cross-border energy leases, a decrease in the current portion of long-term debt, and an increase in income taxes receivable, partially offset by an increase in liabilities and accrued interest related to uncertain tax positions.

At December 31, 2013, PHI's consolidated cash and cash equivalents totaled $23 million, which consisted of cash and uncollected funds but excluded current Restricted Cash Equivalents (cash that is available to be used only for designated purposes) that totaled $13 million. At December 31, 2012, PHI's consolidated cash and cash equivalents totaled $25 million, which consisted of cash and uncollected funds but excluded current Restricted Cash Equivalents that totaled $10 million.

PHI’s short-term debt balances and current portions of long-term debt and project funding balances are summarized below:

Type	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PCI	PHI Consolidated
	As of December 31, 2013 (millions of dollars)							
Variable Rate Demand Bonds	$ —	$—	$105	$ 18	$ —	$ —	$—	$ 123
Commercial Paper	24	151	147	120	—	—	—	442
Total Short-Term Debt	$ 24	$151	$252	$138	$ —	$ —	$—	$ 565
Current Portion of Long-Term Debt and Project Funding	$ —	$175	$100	$107	$ 41	$ 12	$ 11	$ 446

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

Commercial Paper

PHI, Pepco, DPL and ACE maintain commercial paper programs to address short-term liquidity needs. As of December 31, 2013, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $350 million, respectively, subject to available borrowing capacity under the unsecured syndicated credit facility described below.

The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during 2013 was 0.70%, 0.34%, 0.29% and 0.31%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during 2013 was five, five, three and four days, respectively.

Equity Forward Transaction

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

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On August 1, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions, as well as pricing, remained the same after such extension.

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

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

Term Loan Agreements

PHI Term Loan Agreement

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

ACE Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE’s Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of December 31, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.92%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of December 31, 2013.

Long-Term Project Funding

On October 24, 2013, Pepco Energy Services entered into an agreement with a lender to receive up to $8 million in construction financing at an interest rate of 4.68% for an energy savings project that is expected to be completed in 2014. The agreement includes a transfer of receivables from Pepco Energy Services to the lender after construction is completed, under which the customer would make contractual payments over a 23-year period to repay the financing. If there are shortfalls in Pepco Energy Services' energy savings guarantee or other performance obligations to the customer that reduce customer payments below the contractual payment amounts, then Pepco Energy Services would compensate the lender for the unpaid amounts. PHI has guaranteed the performance obligations of Pepco Energy Services under the financing agreement.

Cash and Credit Facility Available as of December 31, 2013

	Consolidated PHI	PHI Parent	Utility Subsidiaries
		(millions of dollars)	
Credit Facility (Total Capacity)	$ 1,500	$ 750	$ 750
Less: Letters of Credit issued	2	2	—
Commercial Paper outstanding	442	24	418
Remaining Credit Facility Available	1,056	724	332
Cash Invested in Money Market Funds and on hand (a)	7	7	—
Total Cash and Credit Facility Available	$ 1,063	$ 731	$ 332

(a) Cash and cash equivalents reported on the PHI consolidated balance sheet totaled $23 million, of which $7 million was invested in money market funds, and the balance was held in cash and uncollected funds.

PHI's Cross-Border Energy Lease Investments

PHI has an ongoing dispute with the IRS regarding the appropriateness of certain significant income tax benefits claimed by PHI related to its cross-border energy lease investments beginning with its 2001 federal income tax return. In the first quarter of 2013, PHI estimated that, in the event the IRS were to be fully successful in its challenge to PHI's tax position on the cross-border energy leases, PHI would have been obligated to pay $192 million in additional federal taxes and $50 million of interest on the additional federal taxes, totaling $242 million as of March 31, 2013. The estimate of additional federal taxes due includes PHI's estimate of the expected resolution of other uncertain and effectively settled tax positions unrelated to the leases, the carrying back or carrying forward of any existing net operating losses, and the application of certain amounts paid in advance to the IRS.

In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made a $242 million advanced payment to the IRS for the estimated additional taxes and related interest in the first quarter of 2013. This advanced payment was funded from then currently available sources of liquidity and short-term borrowings. In March 2013, PHI began to pursue the early termination of its six remaining cross-border energy lease investments, which had a net carrying value of approximately $869 million as of March 31, 2013. During the second and third quarters of 2013, PHI terminated early all of its interests in the six remaining lease investments. PHI received aggregate net cash proceeds of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. A portion of the net cash proceeds from the terminated leases was used to repay borrowings utilized to fund the advanced payment discussed above.

Pension and Other Postretirement Benefit Plans

PHI sponsors a non-contributory, defined benefit pension plan (the PHI Retirement Plan) that covers substantially all employees of Pepco, DPL and ACE and certain employees of other PHI subsidiaries. PHI also provides supplemental retirement benefits to certain eligible executive and key employees through nonqualified retirement plans. PHI's funding policy with regard to the PHI Retirement Plan is to maintain a funding level that is at least equal to the target liability as defined under the Pension Protection Act of 2006.

Under the Pension Protection Act, if a plan incurs a funding shortfall in the preceding plan year, there can be required minimum quarterly contributions in the current and following plan years. In 2014, PHI, Pepco, DPL and ACE do not expect to make discretionary tax-deductible contributions to the PHI Retirement Plan. Management expects that the current balance of the PHI Retirement Plan assets is at least equal to the funding target liability for 2014 under the Pension Protection Act. During 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $80 million, $10 million and $30 million, respectively. During 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. PHI satisfied the minimum required contribution rules under the Pension Protection Act in 2013, 2012 and 2011. For additional discussion of PHI's Pension and Other Postretirement Benefits, see Note (9), "Pension and Other Postretirement Benefits," to the consolidated financial statements of PHI.

PHI provides certain postretirement health care and life insurance benefits for eligible retired employees. Most employees hired on January 1, 2005 or later will not have company subsidized retiree health care coverage; however, they will be able to purchase coverage at full cost through PHI.

In 2013 and 2012, Pepco contributed $6 million and $5 million, respectively, DPL contributed $3 million and $7 million, respectively, and ACE contributed $6 million and $7 million, respectively, to the other postretirement benefit plan. In 2013 and 2012, contributions of $7 million and $13 million, respectively, were made by other PHI subsidiaries.

Based on the results of the 2013 actuarial valuation, PHI's net periodic pension and other postretirement benefit (OPEB) costs were approximately $94 million in 2013 versus $110 million in 2012. The current estimate of benefit cost for 2014 is $67 million. The utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and OPEB costs. Approximately 37% of net periodic pension and OPEB costs were capitalized in 2013. PHI estimates that its net periodic pension and OPEB expense will be approximately $40 million in 2014, as compared to $57 million in 2013 and $67 million in 2012.

Other Postretirement Benefit Plan Amendment

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and retiree life insurance benefits, and were effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation as of July 1, 2013. The remeasurement resulted in a $193 million reduction of the accumulated postretirement benefit obligation, which included recording a prior service credit of $124 million, which will be amortized over approximately ten years, and a $69 million reduction from a change in the discount rate from 4.10% as of December 31, 2012 to 4.95% as of July 1, 2013.

Cash Flow Activity

PHI's cash flows during 2013, 2012 and 2011 are summarized below:

	Cash Source (Use)		
	2013	2012	2011
	(millions of dollars)		
Operating Activities	$ 497	$ 592	$ 686
Investing Activities	(411)	(969)	(747)
Financing Activities	(88)	293	149
Net (decrease) increase in cash and cash equivalents	$ (2)	$ (84)	$ 88

Operating Activities

Cash flows from operating activities during 2013, 2012 and 2011 are summarized below:

	Cash Source (Use)		
	2013	2012	2011
	(millions of dollars)		
Net income from continuing operations	$ 110	$ 218	$ 222
Non-cash adjustments to net income	465	451	410
Pension contributions	(120)	(200)	(110)
Advanced payment made to taxing authority	(242)	—	—
Changes in cash collateral related to derivative activities	31	88	9
Changes in other assets and liabilities	206	60	90
Changes in net current assets held for disposition or sale	47	(25)	65
Net cash from operating activities	$ 497	$ 592	$ 686

Net cash from operating activities decreased $95 million for the year ended December 31, 2013, compared to the same period in 2012. The decrease was primarily due to a decrease in net income of $108 million and a $242 million advanced payment to the IRS for estimated additional taxes and related interest, partially offset by an $80 million decrease in pension contributions and a $72 million reduction in net current assets held for disposition or sale associated with the early termination of all cross-border energy lease investments and the wind-down of Pepco Energy Services' retail electric and natural gas supply businesses.

Net cash from operating activities decreased $94 million for the year ended December 31, 2012, compared to the same period in 2011. The decrease was due primarily to a $90 million increase in pension contributions compared to 2011, the disposition of substantially all of Conectiv Energy's remaining assets in 2011 and a $46 million increase in Pepco Energy Services net assets held for disposition. This was partially offset by a $79 million decrease in cash collateral related to derivative activities.

Investing Activities

Cash flows used by investing activities during 2013, 2012 and 2011 are summarized below:

	Cash (Use) Source 2013	2012	2011
	(millions of dollars)		
Investment in property, plant and equipment	$(1,310)	$(1,216)	$(941)
DOE capital reimbursement awards received	22	40	52
Changes in restricted cash equivalents	1	(1)	(10)
Net other investing activities	3	6	(9)
Proceeds from disposal of assets held for disposition	873	202	161
Net cash used by investing activities	$ (411)	$ (969)	$(747)

Net cash used by investing activities decreased $558 million for the year ended December 31, 2013, compared to the same period in 2012. The decrease was primarily due to proceeds from the early termination of all cross-border energy lease investments.

Net cash used by investing activities increased $222 million for the year ended December 31, 2012, compared to the same period in 2011. The increase was due primarily to a $275 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 lease investments.

Financing Activities

Cash flows from financing activities during 2013, 2012 and 2011 are summarized below:

	Cash (Use) Source 2013	2012	2011
	(millions of dollars)		
Dividends paid on common stock	$(270)	$(248)	$(244)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan (DRP) and employee-related compensation (a)	50	51	47
Issuances of common stock	324	—	—
Redemption of preferred stock of subsidiaries	—	—	(6)
Issuances of long-term debt	800	450	235
Reacquisitions of long-term debt	(558)	(176)	(70)
(Repayments) issuances of short-term debt, net	(200)	33	198
Issuances of term loans	250	200	—
Repayments of term loans	(450)	—	—
Cost of issuances	(23)	(9)	(10)
Net other financing activities	(11)	(8)	(1)
Net cash (used by) from financing activities	$ (88)	$ 293	$ 149

(a) Prior to October 1, 2013, the DRP was named the Shareholder Dividend Reinvestment Plan.

Net cash from financing activities decreased $381 million for the year ended December 31, 2013, compared to the same period in 2012. The decrease was primarily due to a net decrease of $400 million in term loans and an increase of $233 million in short-term debt repayments, partially offset by issuances of common stock of $324 million primarily due to the settlement of the equity forward transaction.

Net cash from financing activities increased $144 million for the year ended December 31, 2012 compared to the same period in 2011. The increase was due primarily to a $200 million term loan issuance and a $109 million net increase in long-term debt partially offset by a $165 million net decrease in short-term debt issuances.

Common Stock Dividends

Common stock dividend payments were $270 million in 2013, $248 million in 2012, and $244 million in 2011. The increase in common stock dividends paid in 2013 and 2012 was the result of additional shares outstanding, primarily shares issued upon settlement of the equity forward transaction in February 2013 and under the DRP.

Changes in Outstanding Common Stock

PHI issued approximately 1 million shares of common stock in each of 2013, 2012 and 2011 under PHI's long-term incentive plans.

Under the DRP, PHI issued 1.6 million shares of common stock in 2013, 1.7 million shares of common stock in 2012, and 1.6 million shares of common stock in 2011.

In February 2013, PHI issued 17.9 million shares of common stock pursuant to the settlement of the equity forward transaction discussed above.

Changes in Outstanding Long-Term Debt

Cash flows from issuances and reacquisitions of long-term debt in 2013, 2012 and 2011 are summarized in the tables below:

Issuances	**2013**	**2012**	**2011**
	(millions of dollars)		
Pepco			
3.05% First mortgage bonds due 2022	$—	$200	$—
4.15% First mortgage bonds due 2043	250	—	—
4.95% First mortgage bonds due 2043	150	—	—
	400	200	—
DPL			
0.75% Tax-exempt bonds due 2026 (a)	—	—	35
4.00% First mortgage bonds due 2042	—	250	—
3.50% First mortgage bonds due 2023	300	—	—
	300	250	35
ACE			
4.35% First mortgage bonds due 2021	—	—	200
Variable rate term loan due 2014	100	—	—
	100	—	200
Pepco Energy Services	—	—	—
	$800	$450	$235

(a) Consists of Pollution Control Refunding Revenue Bonds (DPL Bonds) issued by the Delaware Economic Development Authority (DEDA) 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 adjusted from 4.90% to a fixed rate of 0.75%.

Reacquisitions	2013	2012	2011
	(millions of dollars)		
Pepco			
5.375% Tax-exempt bonds due 2024 (a)	$—	$ 38	$—
4.95% First mortgage bonds due 2013	200	—	—
	200	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(c)	—	15	—
2.30% Tax-exempt bonds due 2028(c)	—	16	—
5.20% Tax-exempt bonds due 2019	—	31	—
6.40% First mortgage bonds due 2013	250	—	—
	250	97	35
ACE			
Securitization bonds due 2011-2013	39	37	35
5.60% First mortgage bonds due 2025(a)	—	4	—
6.625% First mortgage bonds due 2013	69	—	—
	108	41	35
	$558	$176	$ 70

(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.

(c) Repurchased by DPL in June 2012 pursuant to a mandatory purchase obligation and then retired.

Tax Exempt Auction Rate and First Mortgage Bond Issuances

During 2013, Pepco issued $250 million of 4.15% first mortgage bonds due March 15, 2043 and $150 million of 4.95% first mortgage bonds due November 15, 2043. These bonds were issued under a Mortgage and Deed of Trust and are secured thereunder by a first lien, subject to certain leases, permitted liens and other exceptions, on substantially all of Pepco's properties, except for such property excluded from the lien of the Mortgage and Deed of Trust. Net proceeds from the issuance of the 4.15% bonds were used to repay Pepco's outstanding commercial paper and for general corporate purposes. The net proceeds from the 4.95% bonds were used to repay outstanding commercial paper, including commercial paper issued to repay in full at maturity $200 million of Pepco 4.95% senior notes due November 15, 2013, plus accrued but unpaid interest thereon. The senior notes were secured by a like principal amount of Pepco first mortgage bonds, which under Pepco's Mortgage and Deed of Trust were deemed to be satisfied with the repayment of the senior notes.

During 2013, DPL issued $300 million of 3.50% first mortgage bonds due November 15, 2023. These bonds were issued under a Mortgage and Deed of Trust and are secured thereunder by a first lien, subject to certain leases, permitted liens and other exceptions, on substantially all of DPL's properties, except for such property excluded from the lien of the Mortgage and Deed of Trust. The net proceeds from the issuance of the long-term debt were used to repay at maturity $250 million of DPL's 6.40% first mortgage bonds, plus accrued but unpaid interest thereon, to repay outstanding commercial paper and for general corporate purposes.

During 2012, Pepco issued $200 million of 3.05% first mortgage bonds due April 1, 2022. Net proceeds from the issuance of the long-term debt were used primarily (i) to repay Pepco's outstanding commercial paper that was issued to temporarily fund capital expenditures and working capital, (ii) to fund the redemption, prior to maturity, of all of the $38.3 million outstanding of the 5.375% pollution control revenue refunding bonds due in 2024 issued by the Industrial Development Authority of the City of Alexandria, Virginia (IDA), on Pepco's behalf and (iii) for general corporate purposes.

During 2012, DPL issued $250 million of 4.00% first mortgage bonds due June 1, 2042. Net proceeds from the issuance of the long-term debt were used primarily (i) to repay $215 million of DPL's outstanding commercial paper that was issued (a) to temporarily fund capital expenditures and working capital and (b) to fund the redemption in June 2012, prior to maturity, of $65.7 million in aggregate principal amount of three series of outstanding tax-exempt pollution control refunding revenue bonds issued by DEDA for DPL's benefit; (ii) to fund the redemption, prior to maturity, of $31 million of tax-exempt bonds issued by DEDA for DPL's benefit; and (iii) for general corporate purposes.

In 2011, DPL resold $35 million of Pollution Control Refunding Revenue Bonds (Delmarva Power & Light Company Project) Series 2001C due 2026 (the Series 2001C Bonds). The Series 2001C Bonds were issued for the benefit of DPL in 2001 and were repurchased by DPL on May 2, 2011, pursuant to a mandatory repurchase provision in the indenture for the Series 2001C Bonds triggered by the expiration of the original interest rate period specified by the Series 2001C Bonds. See footnote (b) to the Reacquisitions table above.

In connection with the issuance of the Series 2001C Bonds, DPL entered into a continuing disclosure agreement under which it is obligated to furnish certain information to the bondholders. At the time of the resale, the continuing disclosure agreement was amended and restated to designate the Municipal Securities Rulemaking Board as the sole repository for these continuing disclosure documents. The amendment and restatement of the continuing disclosure agreement did not change the operating or financial data that are required to be provided by DPL under such agreement.

In 2011, ACE issued $200 million of 4.35% first mortgage bonds due April 1, 2021. The net proceeds were used to repay short-term debt and for general corporate purposes.

Tax Exempt Auction Rate and First Mortgage Bond Redemptions

During 2013, Pepco repaid at maturity $200 million of its 4.95% senior notes, which were secured by a like principal amount of Pepco's first mortgage bonds as previously discussed.

During 2013, DPL repaid at maturity $250 million of its 6.40% first mortgage bonds.

During 2013, ACE repaid at maturity $69 million of its 6.625% non-callable first mortgage bonds. ACE also funded the redemption, prior to maturity, of $4 million of outstanding weekly rate pollution control revenue refunding bonds due 2017, issued by the Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit.

During 2012, all of the $38.3 million of the outstanding 5.375% pollution control revenue refunding bonds issued by IDA for Pepco's benefit were redeemed. In connection with the redemption, Pepco redeemed all of the $38.3 million outstanding of its 5.375% first mortgage bonds due in 2024 that secured the obligations under the pollution control bonds.

During 2012, DPL funded the redemption by DEDA, prior to maturity, of $65.7 million of outstanding tax-exempt pollution control refunding revenue bonds issued by DEDA for DPL's benefit, as described above. Of the pollution control refunding revenue bonds redeemed, $34.5 million in aggregate principal amount bore interest at 0.75% per year and matured in 2026, $15.0 million in aggregate principal amount bore interest at 1.80% per year and matured in 2025, and $16.2 million in aggregate principal amount bore interest at 2.30% per year and matured in 2028. In connection with such redemption, on June 1, 2012, DPL redeemed, prior to maturity, all of the $34.5 million in aggregate principal amount outstanding of its 0.75% first mortgage bonds due 2026 that secured the obligations under one of the series of pollution control refunding revenue bonds redeemed by DEDA.

During 2012, DPL redeemed, prior to maturity, $31 million of 5.20% tax-exempt pollution control refunding revenue bonds due 2019, issued by DEDA 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.

During 2012, ACE redeemed, prior to maturity, $4 million of 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.

Changes in Short-Term Debt

As of December 31, 2013, PHI had a total of $442 million of commercial paper outstanding as compared to $637 million and $586 million of commercial paper outstanding at December 31, 2012 and 2011, respectively.

On March 28, 2013, PHI entered into a $250 million term loan agreement, pursuant to which PHI had borrowed (and was not permitted to re-borrow) $250 million. PHI used the net proceeds of the loan under the loan agreement to repay its outstanding $200 million term loan made in 2012, and for general corporate purposes. On May 29, 2013, PHI repaid the $250 million term loan with a portion of the net proceeds from the early termination of the cross-border energy lease investments.

Capital Requirements

Capital Expenditures

Pepco Holdings' capital expenditures for the year ended December 31, 2013 totaled $1,310 million, an increase of $94 million from $1,216 million in 2012. Capital expenditures in 2013 were $576 million for Pepco, $357 million for DPL, $261 million for ACE, $4 million for Pepco Energy Services and $112 million for Corporate and Other. The Power Delivery expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. Corporate and Other capital expenditures primarily consisted of hardware and software expenditures that will be allocated to Power Delivery when the assets are placed in service.

The table below shows the projected capital expenditures for Power Delivery, Pepco Energy Services and Corporate and Other for the five-year period 2014 through 2018. PHI expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
	(millions of dollars)					
Power Delivery						
Distribution	$ 774	$ 707	$ 771	$ 729	$ 744	$3,725
Distribution – Smart Grid (AMI)	2	—	—	—	8	10
Transmission	318	290	260	255	285	1,408
Gas Delivery	29	28	28	28	29	142
Other	167	102	99	96	65	529
Total for Power Delivery	1,290	1,127	1,158	1,108	1,131	5,814
Pepco Energy Services	6	6	7	6	3	28
Corporate and Other	6	6	6	6	6	30
Total PHI	$1,302	$1,139	$1,171	$1,120	$1,140	$5,872

Transmission and Distribution

The projected capital expenditures listed in the table for distribution (other than the smart grid), transmission and gas delivery are primarily for facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts. For a more detailed discussion of these efforts, see "General Overview – Power Delivery."

DOE Capital Reimbursement Awards

In 2009, the U.S. Department of Energy (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 direct load control, distribution automation, and communications infrastructure.

Of the total $168 million in DOE awards, $130 million is being used for the smart grid and other capital expenditures of Pepco and ACE. The remaining $38 million is being used to offset incremental expenditures associated with direct load control and other Pepco and ACE programs. During 2013, Pepco and ACE received award payments of $30 million and $4 million, respectively. The cumulative award payments received by Pepco and ACE as of December 31, 2013, were $145 million and $17 million, respectively.

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

Dividends

Pepco Holdings' annual dividend rate on its common stock is determined by the Board of Directors on a quarterly basis and takes into consideration, among other factors, current and possible future developments that may affect PHI's income and cash flows. In 2013, PHI's Board of Directors declared quarterly dividends of 27 cents per share of common stock payable on March 28, 2013, June 28, 2013, September 30, 2013 and December 31, 2013.

On January 23, 2014, the Board of Directors declared a dividend on common stock of 27 cents per share payable March 31, 2014, to shareholders of record on March 10, 2014.

PHI, on a stand-alone basis, generates no operating income of its own. Accordingly, its ability to pay dividends to its shareholders depends on dividends received from its subsidiaries. In addition to their future financial performance, the ability of each of PHI's direct and indirect subsidiaries to pay dividends is subject to limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and when such dividends can be paid, and, in the case of ACE, the regulatory requirement that it obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of existing and future mortgage bonds and other long-term debt issued by the subsidiaries, and any preferred stock that may be issued by the subsidiaries in the future, (iii) any other restrictions imposed in connection with the incurrence of liabilities; and (iv) certain provisions of ACE's charter that impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. None of Pepco, DPL or ACE currently have shares of preferred stock outstanding. Currently, the capitalization ratio limitation to which ACE is subject and the restriction in the ACE charter do not limit ACE's ability to pay common stock dividends. PHI had approximately $595 million and $1,077 million of retained earnings free of restrictions at December 31, 2013 and 2012, respectively. These amounts represent the total retained earnings balances at those dates.

Contractual Obligations and Commercial Commitments

Summary information about Pepco Holdings' consolidated contractual obligations and commercial commitments at December 31, 2013, is as follows:

Contractual Obligations	**Total**	**Contractual Maturity** Less than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(millions of dollars)			
Variable rate demand bonds	$ 123	$ 123	$ —	$ —	$ —
Commercial paper	442	442	—	—	—
Long-term debt (a)	4,725	444	747	419	3,115
Long-term project funding	12	2	3	3	4
Interest payments on debt	3,579	241	441	378	2,519
Capital leases, including interest	91	15	30	30	16
Operating leases	540	44	81	73	342
Estimated OPEB and SERP plan contributions	12	12	—	—	—
Non-derivative power purchase contracts (b)	2,712	278	562	486	1,386
Total (c)	$12,236	$1,601	$1,864	$1,389	$7,382

(a) Includes transition bonds issued by ACE Funding.
(b) Excludes contracts for the purchase of electricity to satisfy Default Electricity Supply load service obligations which have neither a fixed commitment amount nor a minimum purchase amount. In addition, costs are recoverable from customers.
(c) Excludes $606 million of net current and non-current liabilities related to uncertain tax positions due to uncertainty in the timing of the associated cash payments.

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.

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At December 31, 2013, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $190 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects in these businesses. These guarantees totaled $229 million at December 31, 2013.

In addition, PHI guarantees certain obligations of Pepco, DPL and ACE under surety bonds obtained by these subsidiaries, for construction projects and self-insured workers compensation matters. These guarantees totaled $29 million at December 31, 2013.

For additional discussion of PHI's third party guarantees, indemnifications, obligations and off-balance sheet arrangements, see Note (15), "Commitments and Contingencies – Third Party Guarantees, Indemnifications, and Off-Balance Sheet Arrangements," to the consolidated financial statements of PHI.

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 December 31, 2013, a downgrade in the unsecured debt credit ratings of PHI and each of its rated subsidiaries to below "investment grade" would increase the collateral obligation of PHI and its subsidiaries by up to $78 million. This amount is attributable primarily to energy services contracts and accounts payable to independent system operators and distribution companies. PHI believes that it and its subsidiaries currently have sufficient liquidity to fund their operations and meet their financial obligations.

Many of the contractual arrangements entered into by PHI's subsidiaries in connection with Default Electricity Supply activities include margining rights pursuant to which the PHI subsidiary or a counterparty may request collateral if the market value of the contractual obligations reaches levels in excess of the credit thresholds established in the applicable arrangements. Pursuant to these margining rights, the affected PHI subsidiary may receive, or be required to post, collateral due to energy price movements. PHI believes that it and its subsidiaries currently have sufficient liquidity to fund their operations and meet their financial obligations.

Environmental Remediation Obligations

PHI's accrued liabilities for environmental remediation obligations as of December 31, 2013 totaled approximately $30 million, of which approximately $4 million is expected to be incurred in 2014, for potential environmental cleanup and related costs at sites owned or formerly owned by an operating subsidiary where an operating subsidiary is a potentially responsible party or is alleged to be a third-party contributor. For further information concerning the remediation obligations associated with these sites, see Note (15), "Commitments and Contingencies – Environmental Matters," to the consolidated financial statements of PHI. The most significant environmental remediation obligations as of December 31, 2013, are for the following items:

- Environmental investigation and remediation costs payable by Pepco with respect to the Benning Road site.
- Amounts payable by Pepco in connection with a January 2011 mineral oil release at Pepco's Potomac River substation in Alexandria, Virginia.
- Estimated costs for implementation of a closure plan and cap on a Pepco right-of-way that traverses the GenOn MD Ash Management, LLC fly ash disposal site in Brandywine, Prince George's County, Maryland. PHI and Pepco believe that the costs incurred in this matter will be recoverable from GenOn under a 2000 asset purchase and sale agreement, the terms of which specify that the buyer of Pepco's generation assets assumed environmental liability for hazardous substances, including ash, which remain on or have been removed from the land on which the acquired generating stations are situated.
- Costs associated with investigation and resolution of potential impacts from a September 2013 mineral oil release from a Pepco underground feeder to Watts Branch.
- Amounts payable by DPL in accordance with a 2001 consent agreement reached 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 that resulted from an oil release at the Indian River power plant, which DPL sold in June 2001.

- Potential compliance remediation costs under New Jersey's Industrial Site Recovery Act payable by PHI associated with the retained environmental exposure from the sale of the Conectiv Energy wholesale power generation business.
- Amounts payable by DPL in connection with the Wilmington Coal Gas South site located in Wilmington, Delaware, to remediate residual material from the historical operation of a manufactured gas plant.

Sources of Capital

PHI's sources to meet its long-term funding needs, such as capital expenditures, dividends, and new investments, and its short-term funding needs, such as working capital and the temporary funding of long-term funding needs, include internally generated funds, issuances by PHI, Pepco, DPL and ACE under their commercial paper programs, securities issuances, medium- and short-term loans, and bank financing under new or existing facilities. PHI's ability to generate funds from its operations and to access capital and credit markets is subject to risks and uncertainties. Volatile and deteriorating financial market conditions, diminished liquidity and tightening credit may affect access to certain of PHI's potential funding sources.

Cash Flow from Operations

Cash flow generated by regulated utility subsidiaries in Power Delivery is the primary source of PHI's cash flow from operations. Additional cash flows are generated by the business of Pepco Energy Services and from the occasional sale of non-core assets.

Short-Term Funding Sources

Pepco Holdings and its regulated utility subsidiaries have traditionally used a number of sources to fulfill short-term funding needs, such as commercial paper, short-term notes and bank term loans and lines of credit. Proceeds from short-term borrowings are used primarily to meet working capital needs but may also be used to temporarily fund long-term capital requirements. For additional discussion of PHI's short-term debt, see Note (10), "Debt," to the consolidated financial statements of PHI.

Long-Term Funding Sources

The sources of long-term funding for PHI and its subsidiaries are the issuance of debt and equity securities and borrowing under long-term credit agreements. Proceeds from long-term financings are used primarily to fund long-term capital requirements, such as capital expenditures and new investments, and to repay or refinance existing indebtedness.

Regulatory Restrictions on Financing Activities

The issuance of debt securities by PHI's principal subsidiaries requires the approval of either FERC or one or more state public utility commissions. Neither FERC approval nor state public utility commission approval is required as a condition to the issuance of securities by PHI.

State Financing Authority

Pepco's long-term financing activities (including the issuance of securities and the incurrence of long-term debt) are subject to authorization by the DCPSC and MPSC. DPL's long-term financing activities are subject to authorization by the MPSC and the DPSC. ACE's long-term and short-term (consisting of debt instruments with a maturity of one year or less) financing activities are subject to authorization by the NJBPU. Each utility, through periodic filings with the state public service commission(s) having jurisdiction over its financing activities, has maintained standing authority sufficient to cover its projected financing needs over a multi-year period.

FERC Financing Authority

Under the Federal Power Act (FPA), FERC has jurisdiction over the issuance of long-term and short-term securities of public utilities, but only if the issuance is not regulated by the state public utility commission in which the public utility is organized and operating. Under these provisions, FERC has jurisdiction over the issuance of short-term debt by Pepco and DPL. Pepco and DPL have obtained FERC authority for the issuance of short-term debt. Because Pepco Energy Services also qualifies as a public utility under the FPA and is not regulated by a state utility commission, FERC also has jurisdiction over the issuance of securities by Pepco Energy Services. Pepco Energy Services has obtained the requisite FERC financing authority in its market-based rate orders.

Money Pool

Pepco Holdings operates a system money pool under a blanket authorization adopted by FERC. The money pool is an unsecured cash management mechanism used by Pepco Holdings to manage the short-term investment and borrowing requirements of its subsidiaries that participate in the money pool. Pepco Holdings may invest in but not borrow from the money pool. Eligible subsidiaries with surplus cash may deposit those funds in the money pool. Deposits in the money pool are guaranteed by Pepco Holdings. Eligible subsidiaries with cash requirements may borrow from the money pool. Depositors in the money pool receive, and borrowers from the money pool pay, an interest rate based primarily on Pepco Holdings' short-term borrowing rate. Pepco Holdings deposits funds in the money pool to the extent that the pool has insufficient funds to meet the borrowing needs of its participants, which may require Pepco Holdings to borrow funds for deposit from external sources.

Regulatory and Other Matters

<u>*Rate Proceedings*</u>

Distribution

The rates that each of Pepco, DPL and ACE is permitted to charge for the retail distribution of electricity and natural gas to its various classes of customers are based on the principle that the utility is entitled to generate an amount of revenue sufficient to recover the cost of providing the service, including a reasonable rate of return on its invested capital. These "base rates" are intended to cover all of each utility's reasonable and prudent expenses of constructing, operating and maintaining its distribution facilities (other than costs covered by specific cost-recovery surcharges).

A change in base rates in a jurisdiction requires the approval of the public service commission. In the rate application submitted to the public service commission, the utility specifies an increase in its "revenue requirement," which is the additional revenue that the utility is seeking authorization to earn. The "revenue requirement" consists of (i) the allowable expenses incurred by the utility, including operation and maintenance expenses, taxes and depreciation, and (ii) the utility's cost of capital. The compensation of the utility for its cost of capital takes the form of an overall "rate of return" allowed by the public service commission on the utility's distribution "rate base" to compensate the utility's investors for their debt and equity investments in the company. The rate base is the aggregate value of the investment in property used by the utility in providing electricity and natural gas distribution services and generally consists of plant in service net of accumulated depreciation and accumulated deferred taxes, plus cash working capital, material and operating supplies and, depending on the jurisdiction, construction work in progress. Over time, the rate base is increased by utility property additions and reduced by depreciation and property retirements and write-offs.

In addition to its base rates, some of the costs of providing distribution service are recovered through the operation of surcharges. Examples of costs recovered by PHI's utility subsidiaries through surcharges, which vary depending on the jurisdiction, include: a surcharge to reimburse the utility for the cost of purchasing electricity from NUGs (New Jersey); surcharges to reimburse the utility for costs of public interest programs for low income customers and for demand-side management programs (New Jersey, Maryland, Delaware and the District of Columbia); a surcharge to pay the Transitional Bond Charge (New Jersey); surcharges to reimburse the utility for certain environmental costs (Delaware and Maryland); and surcharges related to the BSA (Maryland and the District of Columbia). Each utility subsidiary regularly reviews its distribution rates in each jurisdiction of its service territory, and files applications to adjust its rates as necessary in an effort to ensure that its revenues are sufficient to cover its operating expenses and its cost of capital. The timing of future rate filings and the change in the distribution rate requested will depend on a number of factors, including changes in revenues and expenses and the incurrence or the planned incurrence of capital expenditures. PHI's utility subsidiaries currently plan to, among other things, file electric distribution base rate cases every 9 to 12 months and evaluate potential reductions in planned capital expenditures in an effort to mitigate the effects of regulatory lag. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

In general, a request for new distribution rates is made on the basis of "test year" balances for rate base allowable operating expenses and a requested rate of return. The test year amounts used in the filing may be historical or partially projected. The public service commission may, however, select a different test period than that proposed by the applicable utility. Although the approved tariff rates are intended to be forward-looking, and therefore provide for the recovery of some future changes in rate base and operating costs, they typically do not reflect all of the changes in costs for the period in which the new rates are in effect.

The following table shows, for each of the PHI utility subsidiaries, the authorized return on equity as determined in the most recently concluded base rate proceeding and the effective date of the authorized return:

	Authorized Return on Equity	Rate Effective Date
Pepco:		
District of Columbia (electricity)	9.50%	October 2012
Maryland (electricity)	9.36%	July 2013
DPL:		
Delaware (electricity)	9.75%	July 2012
Maryland (electricity)	9.81% (a)	September 2013
Delaware (natural gas)	9.75% (b)	November 2013
ACE:		
New Jersey (electricity)	9.75%	July 2013

(a) ROE has not been determined by any proceeding and is specified only for the purposes of calculating the AFUDC and regulatory asset carrying costs.

(b) ROE has not been determined by any proceeding and is specified only for reporting purposes and for calculating the AFUDC, construction work in progress (CWIP), regulatory asset carrying costs and other accounting metrics.

Transmission

The rates Pepco, DPL and ACE are permitted to charge for the transmission of electricity are regulated by FERC and are based on each utility's transmission rate base, transmission operating expenses and an overall rate of return that is approved by FERC. For each utility subsidiary, FERC has approved a formula for the calculation of the utility transmission rate, which is referred to as a "formula rate." The formula rates include both fixed and variable elements. Certain of the fixed elements, such as the return on equity and depreciation rates, can be changed only in a FERC transmission rate proceeding. The variable elements of the formula, including the utility's rate base and operating expenses, are updated annually, effective June 1 of each year, with data from the utility's most recent annual FERC Form 1 filing. In addition to its formula rate, each utility's return on equity is supplemented by incentive rates, sometimes referred to as "adders," and other incentives, which are authorized by FERC to promote capital investment in transmission infrastructure. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for PHI's utilities for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. In addition, ROE adders are in effect for each of Pepco, DPL and ACE relating to specific transmission upgrades and improvements, as well as in consideration for each utility's continued membership in PJM. As members of PJM, the transmission rates of Pepco, DPL and ACE are set out in PJM's Open Access Transmission Tariff.

For a discussion of pending state public utility commission and FERC transmission rate and other regulatory proceedings, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Legal Proceedings and Regulatory Matters

For a discussion of legal proceedings, see Note (15), "Commitments and Contingencies," to the consolidated financial statements of PHI, and for a discussion of regulatory matters, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Critical Accounting Policies

General

PHI has identified the following critical accounting policies that result in having to make certain estimates that, as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and estimates involved, could result in material changes in its financial condition or results of operations under different conditions or using different assumptions. PHI has discussed the development, selection and disclosure of each of these policies with the Audit Committee of the Board of Directors.

Goodwill Impairment Evaluation

Substantially all of PHI's goodwill was generated by Pepco's acquisition of Conectiv in 2002 and is allocated entirely to the Power Delivery reporting unit for purposes of assessing impairment under FASB guidance on goodwill and other intangibles (ASC 350). PHI has identified Power Delivery as a single reporting unit because its components have similar economic characteristics, similar products and services, similar distribution methods and support processes, and operate in a similar regulatory environment.

PHI tests its goodwill for impairment annually as of November 1 and whenever an event occurs or circumstances change in the interim that would more likely than not (that is, a greater than 50% chance) reduce the estimated fair value of a reporting unit below the carrying amount of its net assets.

Factors that may result in an interim impairment test include, but are not limited to: an adverse change in business conditions; a protracted decline in stock price causing market capitalization to fall significantly below book value; an adverse regulatory action; impairment of long-lived assets in the reporting unit; or a change in identified reporting units.

The first step of the goodwill impairment test compares the estimated fair value of the reporting unit with its carrying amount, including goodwill. PHI uses its best judgment to make reasonable projections of future cash flows and selection of a discount rate for the associated risk with those cash flows when estimating the reporting unit's fair value. These judgments are inherently uncertain, and actual results could vary from those used in PHI's estimates. The impact of such variations could significantly alter the results of a goodwill impairment test, which could materially impact the estimated fair value of Power Delivery and potentially the amount of any impairment recorded in the financial statements.

PHI's November 1, 2013 annual impairment test indicated that its goodwill was not impaired. See Note (6), "Goodwill," to the consolidated financial statements of PHI.

In order to estimate the fair value of the Power Delivery reporting unit, PHI prepares an analysis of traditional valuation techniques: an income approach and a market approach. The income approach estimates fair value based on a discounted future cash flow analysis and a terminal value that is consistent with Power Delivery's long-term view of the business. This approach uses a discount rate based on the estimated weighted average cost of capital (WACC) for the reporting unit. PHI determines the estimated WACC by considering appropriate market-based information for the cost of equity and cost of debt as of the measurement date. The market approach estimates fair value based on a multiple of earnings before interest, taxes, depreciation, and amortization (EBITDA) that PHI believes is consistent with EBITDA multiples for comparable utilities. PHI has consistently used this valuation technique to estimate the fair value of Power Delivery.

The estimation of fair value is dependent on a number of factors including but not limited to interest rates, growth assumptions, returns on rate base, operating and capital expenditure requirements, and other factors, changes in which could materially impact the results of impairment testing. Assumptions used were consistent with historical experience, including assumptions concerning the recovery of operating costs and capital expenditures, and current market-based information. A hypothetical 10 percent decrease in estimated fair value of the Power Delivery reporting unit at November 1, 2013 would not have resulted in the Power Delivery reporting unit failing the first step of the impairment test, as defined in the guidance, as the estimated fair value of the reporting unit would have been above its carrying value. Sensitive, interrelated and uncertain variables that could decrease the estimated fair value of the Power Delivery reporting unit include utility sector market performance, sustained adverse business conditions, change in forecasted revenues, higher operating and maintenance capital expenditure requirements, a significant increase in the weighted average cost of capital, and other factors.

PHI believes that the estimates involved in its goodwill impairment evaluation process represent "Critical Accounting Estimates" because they are subjective and susceptible to change from period to period as PHI makes assumptions and judgments, and the impact of a change in such assumptions and estimates could be material to financial results.

Long-Lived Assets Impairment Evaluation

PHI believes that the estimates involved in its long-lived asset impairment evaluation process represent "Critical Accounting Estimates" because (i) they are highly susceptible to change from period to period because PHI is required to make assumptions and judgments about when events indicate the carrying value may not be recoverable and how to estimate undiscounted and discounted future cash flows and fair values, which are inherently uncertain, (ii) actual results could vary from those used in PHI's estimates and the impact of such variations could be material, and (iii) the impact that recognizing an impairment would have on PHI's assets as well as the net loss related to an impairment charge could be material. The primary assets subject to a long-lived asset impairment evaluation are property, plant, and equipment.

The FASB guidance on the accounting for the impairment or disposal of long-lived assets (ASC 360), requires that certain long-lived assets must be tested for recoverability whenever events or circumstances indicate that the carrying amount may not be recoverable, such as (i) a significant decrease in the market price of a long-lived asset or asset group, (ii) a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition, (iii) a significant adverse change in legal factors or in the business climate, including an adverse action or assessment by a regulator, (iv) an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset or asset group, (v) a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group, and (vi) a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

An impairment loss may only be recognized if the carrying amount of an asset is not recoverable and the carrying amount exceeds its estimated fair value. The asset is deemed not to be recoverable when its carrying amount exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. PHI uses reasonable estimates in making these evaluations of an asset's future cash flows and considers various factors, including forward price curves for energy, related fuel costs, legislative initiatives, operating costs, and historical cash flows.

Accounting for Derivatives

PHI believes that the estimates involved in accounting for its derivative instruments represent "Critical Accounting Estimates" because PHI exercises judgment in the following areas, any of which could have a material impact on its financial statements: (i) the application of the definition of a derivative to contracts to identify embedded or free-standing derivatives, (ii) the election of the normal purchases and normal sales exception from derivative accounting, (iii) the application of cash flow hedge accounting, and (iv) the estimation of fair value used in the measurement of derivatives and hedged items, which are highly susceptible to changes in value over time due to market trends or, in certain circumstances, significant uncertainties in modeling techniques used to measure fair value that could result in actual results being materially different from PHI's estimates. See Note (2), "Significant Accounting Policies - Accounting for Derivatives," and Note (13), "Derivative Instruments and Hedging Activities," to the consolidated financial statements of PHI.

PHI and its subsidiaries may use derivative instruments primarily to manage risk associated with commodity prices and interest rates. The definition of a derivative in the FASB guidance on derivatives (ASC 815) results in PHI having to exercise judgment, such as whether there is a notional amount or net settlement provision in contracts. PHI assesses a number of factors before determining whether it can designate derivatives for the normal purchase or normal sale exception from derivative accounting, including whether it is probable that the contracts will physically settle with delivery of the underlying commodity. The application of cash flow hedge accounting often requires judgment in the prospective and retrospective assessment and measurement of hedge effectiveness as well as whether it is probable that the forecasted transaction will occur. The fair value of derivatives is determined using quoted exchange prices where available. For instruments that are not traded on an exchange, external broker quotes may also be used to determine fair value. For some custom and complex instruments, internal models use market-based information when external broker quotes are not available. For certain long-dated instruments, broker or exchange data are extrapolated, or capacity prices are forecasted, for future periods where information is limited. Models are also used to estimate volumes for certain transactions. The same valuation methods are used for risk management purposes to determine the value of non-derivative, commodity exposure.

Pension and Other Postretirement Benefit Plans

PHI believes that the estimates involved in reporting the costs of providing pension and OPEB benefits represent Critical Accounting Estimates because (i) they are based on an actuarial calculation that includes a number of assumptions which are subjective in nature, (ii) they are dependent on numerous factors resulting from actual plan experience and assumptions of future experience, and (iii) changes in assumptions could impact PHI's expected future cash funding requirements for the benefit plans and would have an impact on the benefit obligations, which affect the reported amount of net periodic pension and OPEB cost on the consolidated income statement.

Assumptions about the future, including the discount rate applied to benefit obligations, the expected long-term rate of return on plan assets, the anticipated rate of increase in health care costs, average remaining service period and life expectancy, and participant compensation have a significant impact on net periodic pension and OPEB costs.

The discount rate for determining the pension benefit obligation was 5.05% and 4.15% as of December 31, 2013 and 2012, respectively. The discount rate for determining the postretirement benefit obligation was 5.00% and 4.10% as of December 31, 2013 and 2012, respectively. PHI utilizes an analytical tool developed by its actuaries to select the discount rate. The analytical tool utilizes a high-quality bond portfolio with cash flows that match the benefit payments expected to be made under the plans.

The expected long-term rate of return on pension and postretirement benefit plan assets used to determine net periodic pension and OPEB cost was 7.00% and 7.25% for 2013 and 2012, respectively. PHI uses a building block approach to estimate the expected rate of return on plan assets. Under this approach, the percentage of plan assets in each asset class according to PHI's target asset allocation, at the measurement date of net periodic cost, is applied to the expected asset return for the related asset class. PHI incorporates long-term assumptions for real returns, inflation expectations, volatility, and correlations among asset classes to determine expected returns for the related asset class. The pension and postretirement benefit plan assets consist of equity, fixed income, real estate and private equity investments.

The average remaining service periods for participating employees of the benefit plans was approximately 11 years for both 2013 and 2012. PHI utilizes plan census data to estimate these average remaining service periods. PHI uses the IRS prescribed mortality tables to estimate the average life expectancy. The IRS prescribed tables for 2013 and 2012 were used to determine net periodic pension and OPEB cost for the same respective years. The tables for 2014 and 2013 were used for determining the benefit obligations as of December 31, 2013 and 2012, respectively.

The following table reflects the effect on the projected benefit obligation for the pension plans and the accumulated benefit obligation for the OPEB plan, as well as the net periodic cost, if there were changes in these critical actuarial assumptions while holding all other actuarial assumptions constant:

(in millions, except percentages)	Change in Assumptions	Impact on Benefit Obligation	Projected Increase in 2013 Net Periodic Cost
Pension Plans			
Discount rate	(0.25)%	$ 77	$ 6
Expected return	(0.25)%	—	5
Postretirement Benefit Plan (a)			
Discount rate	(0.25)%	16	1
Expected return	(0.25)%	—	1
Health care cost trend rate	1.00%	17	2

(a) The impact on benefit obligation and the projected increase in 2013 net periodic cost were determined assuming that the plan amendments that were effective July 1, 2013 were put into effect on January 1, 2014.

The impact of changes in assumptions and the difference between actual and expected or estimated results on pension and postretirement benefit obligations is generally recognized over the average remaining service period of the employees who benefit under the plans rather than immediate recognition in the statement of income.

For additional discussion, see Note (9), "Pension and Other Postretirement Benefits," to the consolidated financial statements of PHI.

Accounting for Regulated Activities

FASB guidance on the accounting for regulated operations (ASC 980), applies to Power Delivery and can result in the deferral of costs or revenue that would otherwise be recognized by non-regulated entities. PHI defers the recognition of costs and records regulatory assets when it is probable that those costs will be recovered in future customer rates. PHI defers the recognition of revenues and records regulatory liabilities when it is probable that it will refund payments received from customers in the future or that it will incur future costs related to the payments currently received from customers. PHI believes that the judgments involved in accounting for its regulated operations represent "Critical Accounting Estimates" because (i) PHI must interpret laws and regulatory commission orders to assess the probability of the recovery of costs in customer rates or the return of revenues to customers when determining whether those costs or revenues should be deferred, (ii) decisions made by regulatory commissions or legislative changes at a later date could vary from earlier interpretations made by PHI and the impact of such variations could be material, and (iii) the elimination of a regulatory asset because deferred costs are no longer probable of recovery in future customer rates could have a material negative impact on PHI's assets and earnings.

PHI's most significant judgment is whether to defer costs or revenues when there is not a current regulatory order specific to the item being considered for deferral. In those cases, PHI considers relevant historical precedents of the regulatory commissions, the results of recent rate orders, and any new information from its more current interactions with the regulatory commissions on that item. PHI regularly evaluates whether it should defer costs or revenues and reviews whether adjustments to its previous conclusions regarding its regulatory assets and liabilities are necessary based on the current regulatory and legislative environment as well as recent rate orders.

For additional discussion, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Unbilled Revenue

Unbilled revenue represents an estimate of revenue earned from services rendered by PHI's utility operations that have not yet been billed. PHI's utility operations calculate unbilled revenue using an output-based methodology. The calculation is based on the supply of electricity or natural gas distributed to customers but not yet billed, adjusted for estimated line losses (estimates of electricity and gas expected to be lost in the process of a utility's transmission and distribution to customers).

PHI estimates involved in its unbilled revenue process represent "Critical Accounting Estimates" because PHI is required to make assumptions and judgments about factors to the unbilled revenue calculation. Specifically, the determination of estimated line losses is inherently uncertain. Estimated line losses is defined as the estimates of electricity and natural gas expected to be lost in the process of its transmission and distribution to customers. A change in estimated line losses can change the output available for sale which is a factor in the unbilled revenue calculation. Certain factors can influence the estimated line losses such as weather and a change in customer mix. These factors may vary between companies due to geography and density of service territory, and the impact of changes in these factors could be material. PHI seeks to reduce the risk of an inaccurate estimate of unbilled revenue through corroboration of the estimate with historical information and other output-based observable metrics.

Accounting for Income Taxes

PHI exercises significant judgment about the outcome of income tax matters in its application of the FASB guidance on accounting for income taxes (ASC 740) and believes it represents a "Critical Accounting Estimate" because: (i) it records a current tax liability for estimated current tax expense on its federal and state tax returns; (ii) it records deferred tax assets for temporary differences between the financial statement and tax return determination of pre-tax income and the carrying amount of assets and liabilities that are more likely than not going to result in tax deductions in future years; (iii) it determines whether a valuation allowance is needed against deferred tax assets if it is more likely than not that some portion of the future tax deductions will not be realized; (iv) it records deferred tax liabilities for temporary differences between the financial statement and tax return determination of pre-tax income and the carrying amount of assets and liabilities if it is more likely than not that they are expected to result in tax payments in future years; (v) the measurement of deferred tax assets and deferred tax liabilities requires it to estimate future effective tax rates and future taxable income on its federal and state tax returns; (vi) it must consider the effect of newly enacted tax law on its estimated effective tax rate and in measuring deferred tax balances; and (vii) it asserts that tax positions in its tax returns or expected to be taken in its tax returns are more likely than not to be sustained assuming that the tax positions will be examined by taxing authorities with full knowledge of all relevant information prior to recording the related tax benefit in the financial statements.

Assumptions, judgment and the use of estimates are required in determining if the more-likely-than-not measurement threshold (that is, the cumulative result for a greater than 50% chance of being realized) has been met when developing the provision for current and deferred income taxes and the associated current and deferred tax assets and liabilities. PHI's assumptions, judgments and estimates take into account current tax laws and regulations, interpretation of current tax laws and regulations, the impact of newly enacted tax laws and regulations, developments in case law, settlements of tax positions, and the possible outcomes of current and future investigations conducted by tax authorities. PHI has established reserves for income taxes to address potential exposures involving tax positions that could be challenged by tax authorities. Although PHI believes that these assumptions, judgments and estimates are reasonable, changes in tax laws and regulations or its interpretation of tax laws and regulations as well as the resolutions of the current and any future investigations or legal proceedings could significantly impact the financial results from applying the accounting for income taxes in the consolidated financial statements. PHI reviews its application of the more-likely-than-not measurement threshold quarterly.

PHI also evaluates quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and prudent and feasible tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets and the amount of any associated valuation allowance. The forecast of future taxable income is dependent on a number of factors that can change over time, including growth assumptions, business conditions, returns on rate base, operating and capital expenditures, cost of capital, tax laws and regulations, the legal structure of entities and other factors, which could materially impact the realizability of deferred tax assets and the associated financial results in the consolidated financial statements.

New Accounting Standards and Pronouncements

For information concerning new accounting standards and pronouncements that have recently been adopted, or will be required to be adopted in the future, by PHI and its subsidiaries , 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 I(1)(a) and (b) to Form 10-K, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction I(2)(a) to Form 10-K.

General Overview

Pepco is engaged in the transmission and distribution of electricity in the District of Columbia and major portions of Prince George's County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply. Pepco's service territory covers approximately 640 square miles and, as of December 31, 2013, had a population of approximately 2.2 million. As of December 31, 2013, approximately 57% of delivered electricity sales were to Maryland customers and approximately 43% were to District of Columbia customers.

Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenue is not affected by unseasonably warmer or colder weather because a BSA for retail customers was implemented that provides for a fixed distribution charge per customer rather than a charge based on energy usage. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

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

Pepco is a wholly owned subsidiary of PHI. Because PHI is a public utility holding company subject to the Public Utility Holding Company Act of 2005 (PUHCA 2005), the relationship between each of PHI, PHI Service Company (a subsidiary service company of PHI, which provides a variety of support services, including legal, accounting, treasury, tax, purchasing and information technology services to PHI and its operating subsidiaries) and Pepco, as well as certain activities of Pepco, are subject to FERC's regulatory oversight under PUHCA 2005.

Utility Capital Expenditures

Pepco devotes a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territories. These activities include one or more of the following:

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

Pepco's capital expenditures for continuing reliability enhancement efforts are included in the table of projected capital expenditures within "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Requirements – Capital Expenditures."

Smart Grid

Pepco is building a "smart grid" which is designed to meet the challenges of rising energy costs, improve service reliability of the energy distribution system, provide timely and accurate customer information and address government energy reduction goals. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid."

Mitigation of Regulatory Lag

An important factor in the ability of Pepco to earn its authorized ROE is the willingness of the DCPSC and the MPSC to adequately address the shortfall in revenues in Pepco's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." Pepco is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. Pepco had been directed to construct MAPP, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, Pepco submitted a filing to FERC seeking recovery of approximately $50 million of abandoned MAPP costs over a five-year period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

In December 2013, Pepco submitted a settlement agreement to FERC with respect to this matter. Under the terms of the proposed settlement agreement, Pepco would recover its abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. The terms of this settlement, if approved, would not be subject to the pending formula rate or transmission ROE challenges at FERC or modification through any other FERC proceeding. Pepco cannot predict the timing or results of a final FERC decision in this proceeding.

As of December 31, 2013, Pepco had a regulatory asset related to MAPP abandoned costs of $37 million, representing the original filing amount of approximately $50 million of abandoned costs less: (i) approximately $1 million of disallowed costs written off in 2013; (ii) $4 million of materials transferred to inventories for use on other projects; and (iii) $8 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, among others. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that Pepco provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for Pepco is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. Pepco believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, Pepco filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. Pepco cannot predict when a final FERC decision in this proceeding will be issued.

Earnings Overview

Net Income For the Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Pepco's net income for the year ended December 31, 2013 was $150 million compared to $126 million for the year ended December 31, 2012. The $24 million increase in earnings was primarily due to the following:

- An increase of $24 million from electric distribution base rate increases in the District of Columbia and Maryland.
- An increase of $7 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012, partially offset by recovery in 2012 of 2011 storm restoration costs and regulatory expenses.
- An increase of $2 million due to customer growth and other distribution revenue increases.
- An increase of $2 million due to higher transmission revenue attributable to higher rates related to increases in transmission plant investment.
- A decrease of $8 million due to lower tax benefits related to uncertain and effectively settled tax positions.
- A decrease of $5 million due to higher interest expense resulting from an increase in outstanding debt.

Results of Operations

The following results of operations discussion compares the year ended December 31, 2013 to the year ended December 31, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of Pepco's statement of income for the year ended December 31, 2013 compared to the year ended December 31, 2012, is set forth in the table below:

	2013	2012	Change
Operating revenue	$2,026	$1,948	$ 78
Purchased energy	750	726	24
Other operation and maintenance	391	403	(12)
Depreciation and amortization	196	190	6
Other taxes	368	372	(4)
Total operating expenses	1,705	1,691	14
Operating income	321	257	64
Other income (expenses)	(92)	(83)	(9)
Income before income tax expense	229	174	55
Income tax expense	79	48	31
Net income	$ 150	$ 126	$ 24

Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$1,215	$1,159	$ 56
Default Electricity Supply Revenue	778	755	23
Other Electric Revenue	33	34	(1)
Total Operating Revenue	$2,026	$1,948	$ 78

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 territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

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

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 359	$ 339	$ 20
Commercial and industrial	678	658	20
Transmission and other	178	162	16
Total Regulated T&D Electric Revenue	$1,215	$1,159	$ 56

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	7,832	7,742	90
Commercial and industrial	17,806	18,104	(298)
Transmission and other	163	160	3
Total Regulated T&D Electric Sales	25,801	26,006	(205)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	727	720	7
Commercial and industrial	74	73	1
Transmission and other	—	—	—
Total Regulated T&D Electric Customers	801	793	8

Regulated T&D Electric Revenue increased by $56 million primarily due to:

- An increase of $41 million due to distribution rate increases in the District of Columbia effective October 2012 and in Maryland effective July 2012 and July 2013.
- An increase of $10 million in transmission revenue rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $8 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $4 million in transmission revenue primarily attributable to higher capacity as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).
- An increase of $2 million due to customer growth in 2013, primarily in the residential class.

The aggregate amount of these increases was partially offset by:

- A decrease of $7 million in transmission revenue associated with the change in FERC formula rate true-ups.
- A decrease of $4 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a decrease in utility taxes collected by Pepco on behalf of Montgomery County, Maryland.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$ 539	$ 537	$ 2
Commercial and industrial	222	206	16
Other	17	12	5
Total Default Electricity Supply Revenue	$ 778	$ 755	$ 23

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	5,944	6,092	(148)
Commercial and industrial	2,700	2,670	30
Other	14	7	7
Total Default Electricity Supply Sales	8,658	8,769	(111)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	569	574	(5)
Commercial and industrial	44	44	—
Other	—	—	—
Total Default Electricity Supply Customers	613	618	(5)

Default Electricity Supply Revenue increased by $23 million primarily due to:

- An increase of $27 million as a result of higher Default Electricity Supply rates.
- An increase of $5 million primarily due to higher revenue from transmission enhancement credits.
- An increase of $2 million due to higher sales, primarily as a result of colder weather during the 2013 fall months, as compared to 2012.

The aggregate amount of these increases was partially offset by a decrease of $11 million due to lower sales, primarily as a result of customer migration to competitive suppliers.

The following table shows the percentages of Pepco's total distribution sales by jurisdiction that are derived from customers receiving Default Electricity Supply from Pepco. Amounts are for the year ended December 31:

	2013	2012
Sales to District of Columbia customers	25%	25%
Sales to Maryland customers	41%	40%

<u>*Operating Expenses*</u>

Purchased Energy

Purchased Energy consists of the cost of electricity purchased by Pepco to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy increased by $24 million to $750 million in 2013 from $726 million in 2012 primarily due to:

- An increase of $33 million due to higher average electricity costs under Default Electricity Supply contracts.
- An increase of $2 million due to higher electricity sales primarily as a result of colder weather during the 2013 fall months, as compared to 2012.

The aggregate amount of these increases was partially offset by a decrease of $11 million primarily due to customer migration to competitive suppliers.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $12 million to $391 million in 2013 from $403 million in 2012 primarily due to:

- A decrease of $10 million associated with lower maintenance and tree trimming costs.
- A decrease of $7 million in other storm restoration costs.
- A decrease of $4 million in customer service costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $4 million primarily due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Regulatory asset established for future recovery of January 2011 winter storm costs	$ —	$ (9)	$ 9
Costs associated with derecho storm (June 2012)	—	22	(22)
Regulatory assets established for future recovery of derecho storm costs	—	(19)	19
Costs associated with Hurricane Sandy (October 2012)	—	6	(6)
Regulatory assets established for future recovery of Hurricane Sandy costs	—	(4)	4
Total incremental major storm restoration costs	$ —	$ (4)	$ 4

  - 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 over a five-year period.
  - During 2012, Pepco incurred incremental storm restoration costs of $22 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 $19 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 for Pepco in its July 2013 rate order over a five-year period. The remaining costs of $3 million relate to repair work completed in the District of Columbia which are not deferrable.
  - In the fourth quarter of 2012, Pepco incurred incremental storm restoration costs of $6 million associated with Hurricane Sandy which resulted in widespread damage to the electric distribution system in each of Pepco's service territories. Pepco deferred $4 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland. The MPSC approved the recovery of these costs for Pepco in its July 2013 rate order over a five-year period. The remaining costs of $2 million relate to repair work completed in the District of Columbia which are not deferrable.
- An increase of $3 million in environmental remediation costs.
- An increase of $1 million associated with the write-off of disallowed MAPP costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $6 million to $196 million in 2013 from $190 million in 2012 primarily due to:

- An increase of $8 million in amortization of MAPP abandonment costs (which is offset in Regulated T&D Electric Revenue).
- An increase of $4 million in amortization of regulatory assets primarily related to recoverable major storm costs and rate case costs.
- An increase of $2 million associated with expanding Maryland demand side management programs (which is offset in Regulated T&D Electric Revenue).

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million primarily due to lower depreciation rates, partially offset by plant additions.
- A decrease of $3 million in amortization of software related to AMI projects.

Other Taxes

Other Taxes decreased by $4 million to $368 million in 2013 from $372 million in 2012. The decrease was primarily due to decreases in the Montgomery County, Maryland utility taxes that are collected and passed through by Pepco (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $9 million to a net expense of $92 million in 2013 from a net expense of $83 million in 2012. The increase was primarily due to an increase of $9 million in interest expense primarily associated with higher long-term debt.

Income Tax Expense

Pepco's income tax expense increased by $31 million to $79 million in 2013 from $48 million in 2012. Pepco's effective income tax rates for the years ended December 31, 2013 and 2012 were 34.5% and 27.6%, respectively. The increase in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

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

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

Capital Requirements

Sources of Capital

Pepco has a range of capital sources available, in addition to internally generated funds, to meet its long-term and short-term funding needs. The sources of long-term funding include the issuance of mortgage bonds and other debt securities and bank financings, as well as the ability to issue preferred stock. Proceeds from long-term financings are used primarily to fund long-term capital requirements, such as capital expenditures, and to repay or refinance existing indebtedness. Pepco traditionally has used a number of sources to fulfill short-term funding needs, including commercial paper, short-term notes, bank lines of credit and borrowings under the PHI money pool. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements. Pepco's ability to generate funds from its operations and to access the capital and credit markets is subject to risks and uncertainties. Volatile and deteriorating financial market conditions, diminished liquidity and tightening credit may affect access to certain of Pepco's potential funding sources.

Debt Securities

Pepco has a Mortgage and Deed of Trust (the Mortgage) under which it issues First Mortgage Bonds. First Mortgage Bonds issued under the Mortgage are secured by a lien on substantially all of Pepco's property, plant and equipment, except for such property excluded from the lien of the Mortgage. The principal amount of First Mortgage Bonds that Pepco may issue under the Mortgage is limited by the principal amount of retired First Mortgage Bonds and 60% of the lesser of the cost or fair value of new property additions that have not been used as the basis for the issuance of additional First Mortgage Bonds. Pepco also has an indenture under which it issues senior notes secured by First Mortgage Bonds and an indenture under which it can issue unsecured debt securities, including medium-term notes. To fund the construction of pollution control facilities, Pepco also has from time to time raised capital through tax-exempt bonds issued by a municipality or public agency, the proceeds of which are loaned to Pepco by the municipality or agency.

Information concerning the principal amount and terms of Pepco's outstanding debt securities, as of December 31, 2013, is set forth in Note (9), "Debt," to the financial statements of Pepco.

Bank Financing

As further discussed in Note (9), "Debt," to the financial statements of Pepco, Pepco is a borrower under a $1.5 billion unsecured syndicated credit facility, along with PHI, DPL and ACE, which expires in August 2018. This credit facility provides for Pepco's liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting its commercial paper program. Pepco's credit limit under the facility is the lesser of $250 million and the maximum amount of short-term debt Pepco is permitted to have outstanding by its regulatory authorities. The short-term borrowing limit established by FERC for Pepco is $500 million.

Commercial Paper Program

Pepco maintains an ongoing commercial paper program to address its short-term liquidity needs. As of December 31, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

Pepco had $151 million of commercial paper outstanding at December 31, 2013. The weighted average interest rate for commercial paper issued by Pepco during 2013 was 0.34% and the weighted average maturity of all commercial paper issued by Pepco during 2013 was five days.

Money Pool

Pepco participates in the money pool operated by PHI under authorization received from FERC. The money pool is an unsecured cash management mechanism used by PHI and eligible subsidiaries to manage their short-term investment and borrowing requirements. PHI may invest in, but not borrow from, the money pool. Eligible subsidiaries with surplus cash may deposit those funds in the money pool. Deposits in the money pool are guaranteed by PHI. Eligible subsidiaries with cash requirements may borrow from the money pool. Depositors in the money pool receive, and borrowers from the money pool pay, an interest rate based primarily on PHI's short-term borrowing rate. PHI deposits funds in the money pool to the extent that the pool has insufficient funds to meet the borrowing needs of its participants, which may require PHI to borrow funds for deposit from external sources.

Preferred Stock

Under its Articles of Incorporation, Pepco is authorized to issue and have outstanding up to 6 million shares of preferred stock in one or more series, with each series having such rights, preferences and limitations, including dividend and voting rights and redemption provisions, as the Board of Directors may establish. As of December 31, 2013 and 2012, there were no shares of Pepco preferred stock outstanding.

Regulatory Restrictions on Financing Activities

Pepco's long-term financing activities (including the issuance of securities and the incurrence of debt) are subject to authorization by the DCPSC and MPSC. Through its periodic filings with the respective utility commissions, Pepco generally maintains standing authority sufficient to cover its projected financing needs over a multi-year period. Under the FPA, FERC has jurisdiction over the issuance of long-term and short-term securities of public utilities, but only if the issuance is not regulated by the state public utility commission in which the public utility is organized and operating. Pepco has obtained FERC authorization for the issuance of short-term debt under these provisions.

Capital Expenditures

Pepco's capital expenditures for the year ended December 31, 2013 were $576 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's projected capital expenditures for the five-year period from 2014 through 2018 are summarized below. Pepco expects to fund these expenditures through internally generated cash, external financing and capital contributions from PHI.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
	(millions of dollars)					
Pepco						
Distribution	$505	$480	$481	$442	$465	$2,373
Transmission	113	74	43	74	91	395
Other	91	54	36	29	23	233
Total Pepco	$709	$608	$560	$545	$579	$3,001

Pepco has several construction projects within its service territory where performance has been subcontracted to Pepco Energy Services. Pepco guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for these projects. These guarantees totaled $14 million at December 31, 2013.

Transmission and Distribution

The projected capital expenditures listed in the table above for distribution and transmission are primarily for facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts.

DOE Capital Reimbursement Awards

During 2009, the DOE announced a $168 million award to PHI under the American Recovery and Reinvestment Act of 2009 for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure. Pepco was awarded $149 million, with $105 million to be used in the Maryland service territory and $44 million to be used in the District of Columbia service territory.

During 2010, Pepco and the DOE signed agreements formalizing Pepco's $149 million share of the $168 million award. Of the $149 million, $118 million is being used for the smart grid and other capital expenditures of Pepco. The remaining $31 million is being used to offset incremental expenditures associated with direct load control and other programs. During 2013, Pepco received award payments of $30 million. The cumulative award payments received by Pepco as of December 31, 2013, were $145 million.

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

Pension and Other Postretirement Benefit Plans

Pepco participates in pension and OPEB plans sponsored by PHI for its employees. Pepco contributed $85 million to the PHI Retirement Plan during 2012. In 2013 and 2012, Pepco contributed $6 million and $5 million, respectively, to the other postretirement benefit plan.

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 I(1)(a) and (b) to Form 10-K, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction I(2)(a) to Form 10-K.

General Overview

DPL is engaged in the transmission and distribution of electricity in portions of Delaware and Maryland. DPL also provides Default Electricity Supply. DPL's electricity distribution service territory covers approximately 5,000 square miles and, as of December 31, 2013, had a population of approximately 1.4 million. As of December 31, 2013, approximately 66% of delivered electricity sales were to Delaware customers and approximately 34% were to Maryland customers. In northern Delaware, DPL also supplies and distributes natural gas to retail customers and provides transportation-only services to retail customers who purchase natural gas from other suppliers. DPL's natural gas distribution service territory covers approximately 275 square miles and, as of December 31, 2013, had a population of approximately 500,000.

DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a BSA for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

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

DPL is a wholly owned subsidiary of Conectiv 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.

Utility Capital Expenditures

DPL devotes a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territories. These activities include one or more of the following:

- Identifying and upgrading under-performing feeders;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

DPL's capital expenditures for continuing reliability enhancement efforts are included in the table of projected capital expenditures within "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Requirements – Capital Expenditures."

Smart Grid

DPL is building a smart grid which is designed to meet the challenges of rising energy costs, improve service reliability of the energy distribution system, provide timely and accurate customer information and address government energy reduction goals. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid."

Mitigation of Regulatory Lag

An important factor in the ability of DPL to earn its authorized ROE is the willingness of the DPSC and the MPSC to adequately address the shortfall in revenues in DPL's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." DPL is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. DPL had been directed to construct MAPP, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, DPL submitted a filing to FERC seeking recovery of $38 million of abandoned MAPP costs over a five-year period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

In December 2013, DPL submitted a settlement agreement to FERC with respect to this matter. Under the terms of the proposed settlement agreement, DPL would recover its abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. The terms of this settlement, if approved, would not be subject to the pending formula rate or transmission ROE challenges at FERC or modification through any other FERC proceeding. DPL cannot predict the timing or results of a final FERC decision in this proceeding.

As of December 31, 2013, DPL had a regulatory asset related to the MAPP abandoned costs of $31 million, representing the original filing amount of approximately $38 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; and (ii) $6 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against DPL, among others. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that DPL provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for DPL is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. DPL believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, DPL filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. DPL cannot predict when a final FERC decision in this proceeding will be issued.

Earnings Overview

Net Income For the Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

DPL's net income for the year ended December 31, 2013 was $89 million compared to $73 million for the year ended December 31, 2012. The $16 million increase in earnings was primarily due to the following:

- An increase of $16 million from electric distribution base rate increases in Maryland and Delaware.
- An increase of $8 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012.
- An increase of $6 million primarily due to higher sales from colder winter weather, partially offset by lower sales from milder summer weather.
- A decrease of $6 million associated with Default Electricity Supply margins for DPL Delaware, primarily due to favorable adjustments in 2012 related to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes.
- A decrease of $4 million due to higher depreciation and amortization expense associated primarily with regulatory assets and increases in plant investment, partially offset by lower depreciation rates.
- A decrease of $2 million due to higher interest expense resulting from an increase in outstanding debt.

Results of Operations

The following results of operations discussion compares the year ended December 31, 2013 to the year ended December 31, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of DPL's statement of income for the year ended December 31, 2013 compared to the year ended December 31, 2012, is set forth in the table below:

	2013	2012	Change
Operating revenue	$1,244	$1,233	$ 11
Purchased energy	552	568	(16)
Gas purchased	109	113	(4)
Other operation and maintenance	251	260	(9)
Depreciation and amortization	107	102	5
Other taxes	40	36	4
Total operating expenses	1,059	1,079	(20)
Operating income	185	154	31
Other income (expenses)	(40)	(37)	(3)
Income before income tax expense	145	117	28
Income tax expense	56	44	12
Net income	$ 89	$ 73	$ 16

Electric Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$ 502	$ 455	$ 47
Default Electricity Supply Revenue	538	579	(41)
Other Electric Revenue	13	16	(3)
Total Electric Operating Revenue	$1,053	$1,050	$ 3

The table above shows the amount of Electric Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to DPL's customers within its service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

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

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 232	$ 213	$ 19
Commercial and industrial	144	133	11
Transmission and other	126	109	17
Total Regulated T&D Electric Revenue	$ 502	$ 455	$ 47

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	5,122	5,051	71
Commercial and industrial	7,295	7,540	(245)
Transmission and other	48	50	(2)
Total Regulated T&D Electric Sales	12,465	12,641	(176)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	445	442	3
Commercial and industrial	60	60	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	506	503	3

Regulated T&D Electric Revenue increased by $47 million primarily due to:

- An increase of $27 million due to distribution rate increases in Maryland effective July 2012 and September 2013, and in Delaware effective July 2012 and October 2013.
- An increase of $7 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset in Purchased Energy and Depreciation and Amortization).
- An increase of $5 million primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset in Purchased Energy and Depreciation and Amortization).
- An increase of $6 million in transmission revenue related to the recovery of MAPP abandonment costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $4 million in transmission revenue rates effective June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $1 million in distribution revenue related to customer growth in all Delaware and Maryland customer classes.

The aggregate amount of these increases was partially offset by:

- A decrease of $7 million due to lower non-weather related average customer usage.
- A decrease of $1 million in transmission revenue associated with the change in FERC formula rate true-ups.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$ 412	$ 448	$ (36)
Commercial and industrial	114	121	(7)
Other	12	10	2
Total Default Electricity Supply Revenue	$ 538	$ 579	$ (41)

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	4,464	4,579	(115)
Commercial and industrial	1,342	1,622	(280)
Other	27	29	(2)
Total Default Electricity Supply Sales	5,833	6,230	(397)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	390	402	(12)
Commercial and industrial	38	39	(1)
Other	—	1	(1)
Total Default Electricity Supply Customers	428	442	(14)

Default Supply Revenue decreased by $41 million primarily due to:

- A decrease of $27 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $17 million as a result of lower Default Electricity Supply rates.
- A decrease of $8 million due to lower non-weather related average customer usage.

The aggregate amount of these decreases was partially offset by an increase of $8 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.

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 years ended December 31:

	2013	2012
Sales to Delaware customers	44%	47%
Sales to Maryland customers	51%	53%

Natural Gas Operating Revenue

	2013	2012	Change
Regulated Gas Revenue	$165	$151	$ 14
Other Gas Revenue	26	32	(6)
Total Natural Gas Operating Revenue	$191	$183	$ 8

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

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 103	$ 94	$ 9
Commercial and industrial	52	47	5
Transportation and other	10	10	—
Total Regulated Gas Revenue	$ 165	$ 151	$ 14

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	7,861	6,428	1,433
Commercial and industrial	4,945	3,636	1,309
Transportation and other	6,990	6,751	239
Total Regulated Gas Sales	19,796	16,815	2,981

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	117	115	2
Commercial and industrial	9	10	(1)
Transportation and other	—	—	—
Total Regulated Gas Customers	126	125	1

Regulated Gas Revenue increased by $14 million primarily due to:

- An increase of $22 million due to higher sales primarily as a result of colder weather during the winter months of 2013 as compared to 2012.
- An increase of $7 million due to higher non-weather related average commercial customer usage.
- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by an increase in Purchased Energy).
- An increase of $2 million due to a distribution rate increase effective July 2013.

The aggregate amount of these increases was partially offset by a decrease of $22 million due to a GCR decrease effective November 2012.

Other Gas Revenue

Other Gas Revenue decreased by $6 million primarily due to lower average prices and lower volumes for off-system sales to electric generators and gas marketers.

Operating Expenses

Purchased Energy consists of the cost of electricity purchased by DPL to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy decreased by $16 million to $552 million in 2013 from $568 million in 2012 primarily due to:

- A decrease of $39 million primarily due to customer migration to competitive suppliers.
- A decrease of $20 million in deferred electricity expense primarily due to higher Default Electricity Supply cost of service rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $17 million due to higher average electricity costs under Default Electricity Supply contracts.
- An increase of $13 million in deferred electricity expense primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset in Regulated T&D Electric Revenue and Depreciation and Amortization).
- An increase of $7 million due to higher electricity sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.
- An increase of $4 million in the costs associated with purchasing Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $2 million in the costs associated with purchases under wind power purchase agreements in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

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 $4 million to $109 million in 2013 from $113 million in 2012 primarily due to:

- A decrease of $13 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 $5 million in the cost of gas purchases for off-system sales as a result of lower volumes.

The aggregate amount of these decreases was partially offset by:

- An increase of $11 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $9 million to $251 million in 2013 from $260 million in 2012 primarily due to:

- A decrease of $5 million associated with lower maintenance costs.
- A decrease of $5 million primarily due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	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 Sandy (October 2012)	—	9	(9)
Regulatory asset established for future recovery of Hurricane Sandy costs	—	(5)	5
Total incremental major storm restoration costs	$ —	$ 5	$ (5)

  - During 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. The MPSC approved the recovery of these costs for DPL in its August 2013 electric distribution base rate order over a five-year period. The remaining costs of $1 million relate to repair work completed in Delaware which are not deferrable.
  - In the fourth quarter of 2012, DPL incurred incremental storm restoration costs of $9 million associated with Hurricane Sandy which 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 for DPL in its August 2013 electric distribution base rate order over a five-year period. The remaining costs of $4 million relate to repair work completed in Delaware which are not deferrable.
- A decrease of $4 million in customer service costs.
- A decrease of $4 million in other storm restoration costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $6 million resulting from 2012 deferred cost adjustments associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes.
- An increase of $2 million associated with the write-offs of disallowed MAPP and associated transmission projects costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $5 million to $107 million in 2013 from $102 million in 2012 primarily due to:

- An increase of $6 million in amortization of MAPP abandonment costs (which is offset by a corresponding increase in Regulated T&D Electric Revenue).

- An increase of $4 million due to utility plant additions.
- An increase of $2 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.

The aggregate amount of these increases was partially offset by a decrease of $7 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Fuel and Purchased Energy).

Other Taxes

Other Taxes increased by $4 million to $40 million in 2013 from $36 million in 2012. The increase was primarily due to higher property taxes.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $3 million to a net expense of $40 million in 2013 from a net expense of $37 million in 2012. The increase was primarily due to an increase in long-term debt interest expense due to the issuance of $250 million of First Mortgage Bonds in June 2012.

Income Tax Expense

DPL's income tax expense increased by $12 million to $56 million in 2013 from $44 million in 2012. DPL's effective income tax rates for the years ended December 31, 2013 and 2012 were 38.6% and 37.6%, respectively. The increase in the effective tax rate primarily resulted from adjustments to prior year taxes recorded during the year ended December 31, 2012.

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

Capital Requirements

Sources of Capital

DPL has a range of capital sources available, in addition to internally generated funds, to meet its long-term and short-term funding needs. The sources of long-term funding include the issuance of mortgage bonds and other debt securities and bank financings, as well as the ability to issue preferred stock. Proceeds from long-term financings are used primarily to fund long-term capital requirements, such as capital expenditures, and to repay or refinance existing indebtedness. DPL traditionally has used a number of sources to fulfill short-term funding needs, including commercial paper, medium- and short-term notes, bank lines of credit, and borrowings under the PHI money pool. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements. DPL's ability to generate funds from its operations and to access the capital and credit markets is subject to risks and uncertainties. Volatile and deteriorating financial market conditions, diminished liquidity and tightening credit may affect access to certain of DPL's potential funding sources.

Debt Securities

DPL has a Mortgage and Deed of Trust (the Mortgage) under which it issues First Mortgage Bonds. First Mortgage Bonds issued under the Mortgage are secured by a lien on substantially all of DPL's property, plant and equipment, except for such property excluded from the lien of the Mortgage. The principal amount of First Mortgage Bonds that DPL may issue under the Mortgage is limited by the principal amount of retired First Mortgage Bonds and 60% of the lesser of the cost or fair value of new property additions that have not been used as the basis for the issuance of additional First Mortgage Bonds. DPL also has an indenture under which it issues unsecured senior notes, medium-term notes and Variable Rate Demand Bonds (VRDBs). To fund the construction of pollution control facilities, DPL also has from time to time raised capital through tax-exempt bonds, including tax-exempt VRDBs, issued by a public agency, the proceeds of which are loaned to DPL by the agency.

Information concerning the principal amount and terms of DPL's outstanding First Mortgage Bonds, senior notes, medium-term notes and tax-exempt bonds issued for the benefit of DPL, as of December 31, 2013, is set forth in Note (10), "Debt," to the financial statements of DPL.

Bank Financing

As further discussed in Note (10), "Debt," to the financial statements of DPL, DPL is a borrower under a $1.5 billion unsecured syndicated credit facility, along with PHI, Pepco and ACE, which expires in August 2018. This credit facility provides for DPL's liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting its commercial paper program. DPL's credit limit under the facility is the lesser of $250 million and the maximum amount of short-term debt DPL is permitted to have outstanding by its regulatory authorities. The short-term borrowing limit established by FERC for DPL is $500 million.

Commercial Paper Program

DPL maintains an ongoing commercial paper program to address its short-term liquidity needs. As of December 31, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had $147 million of commercial paper outstanding at December 31, 2013. The weighted average interest rate for commercial paper issued by DPL during 2013 was 0.29% and the weighted average maturity of all commercial paper issued by DPL during 2013 was three days.

Money Pool

DPL participates in the money pool operated by PHI under authorization received from FERC. The money pool is an unsecured cash management mechanism used by PHI and eligible subsidiaries to manage their short-term investment and borrowing requirements. PHI may invest in, but not borrow from, the money pool. Eligible subsidiaries with surplus cash may deposit those funds in the money pool. Deposits in the money pool are guaranteed by PHI. Eligible subsidiaries with cash requirements may borrow from the money pool. Depositors in the money pool receive, and borrowers from the money pool pay, an interest rate based primarily on PHI's short-term borrowing rate. PHI deposits funds in the money pool to the extent that the pool has insufficient funds to meet the borrowing needs of its participants, which may require PHI to borrow funds for deposit from external sources.

<u>Regulatory Restrictions on Financing Activities</u>

DPL's long-term financing activities (including the issuance of securities and the incurrence of debt) is subject to authorization by the DPSC and the MPSC. Through its periodic filings with the respective utility commissions, DPL generally maintains standing authority sufficient to cover its projected financing needs over a multi-year period. Under the FPA, FERC has jurisdiction over the issuance of long-term and short-term securities of public utilities, but only if the issuance is not regulated by the state public utility commission in which the public utility is organized and operating. DPL has obtained FERC authorization for the issuance of short-term debt under these provisions.

Capital Expenditures

DPL's capital expenditures for the year ended December 31, 2013 were $357 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's projected capital expenditures for the five-year period from 2014 through 2018 are summarized below. DPL expects to fund these expenditures through internally generated cash, external financing and capital contributions from PHI.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
			(millions of dollars)			
DPL						
Distribution	$162	$149	$153	$159	$155	$ 778
Distribution – Smart Grid (AMI)	2	—	—	—	—	2
Transmission	96	88	119	96	138	537
Gas Delivery	29	28	28	28	29	142
Other	51	32	24	28	20	155
Total DPL	$340	$297	$324	$311	$342	$1,614

Transmission and Distribution

The projected capital expenditures listed in the table above for distribution (other than the smart grid), transmission and gas delivery are primarily for facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for reliability enhancement efforts.

Pension and Other Postretirement Benefit Plans

DPL participates in pension and OPEB plans sponsored by PHI for its employees. DPL contributed $10 million and $85 million to the PHI Retirement Plan during 2013 and 2012, respectively. In 2013 and 2012, DPL contributed $3 million and $7 million, respectively, to the other postretirement benefit plan.

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 I(1)(a) and (b) to Form 10-K, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction I(2)(a) to Form 10-K.

General Overview

ACE is engaged in the transmission and distribution of electricity in portions of southern New Jersey. ACE also provides Default Electricity Supply. Default Electricity Supply is known as BGS in New Jersey. ACE's service territory covers approximately 2,700 square miles and, as of December 31, 2013, had a population of approximately 1.1 million.

ACE is a wholly owned subsidiary of Conectiv, which is wholly owned by PHI. Because each of PHI and Conectiv is a public utility holding company subject to PUHCA 2005, the relationship between each of PHI, Conectiv, PHI Service Company and ACE, as well as certain activities of ACE, are subject to FERC's regulatory oversight under PUHCA 2005.

Utility Capital Expenditures

ACE devotes a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territory. These activities include one or more of the following:

- Identifying and upgrading under-performing feeders;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

ACE's capital expenditures for continuing reliability enhancement efforts are included in the table of projected capital expenditures within "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Requirements – Capital Expenditures."

Mitigation of Regulatory Lag

An important factor in the ability of ACE to earn its authorized ROE is the willingness of the NJBPU to adequately address the shortfall in revenues in ACE's rate structure due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." ACE is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against ACE, among others. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that ACE provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for ACE is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. ACE believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, ACE filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. ACE cannot predict when a final FERC decision in this proceeding will be issued.

Earnings Overview

Net Income For the Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

ACE's consolidated net income for the year ended December 31, 2013 was $50 million compared to $35 million for the year ended December 31, 2012. The $15 million increase in earnings was primarily due to the following:

- An increase of $24 million from electric distribution base rate increases in New Jersey.
- An increase of $6 million due to higher tax benefits related to uncertain and effectively settled tax positions.
- An increase of $3 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012.
- A decrease of $8 million due to higher depreciation and amortization expense associated primarily with regulatory assets and increases in plant investment.
- A decrease of $4 million due to lower non-weather related average customer usage in New Jersey.
- A decrease of $2 million primarily due to lower sales from milder summer weather.
- A decrease of $2 million due to lower income related to AFUDC that is applied to capital projects.

Results of Operations

The following results of operations discussion compares the year ended December 31, 2013 to the year ended December 31, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of ACE's consolidated statement of income for the year ended December 31, 2013 compared to the year ended December 31, 2012, is set forth in the table below:

	2013	2012	Change
Operating revenue	$1,202	$1,198	$ 4
Purchased energy	660	703	(43)
Other operation and maintenance	230	239	(9)
Depreciation and amortization	136	124	12
Other taxes	14	18	(4)
Deferred electric service costs	26	(5)	31
Total operating expenses	1,066	1,079	(13)
Operating income	136	119	17
Other income (expenses)	(67)	(66)	(1)
Income before income tax expense	69	53	16
Income tax expense	19	18	1
Consolidated Net Income	$ 50	$ 35	$ 15

Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$ 429	$ 392	$ 37
Default Electricity Supply Revenue	759	790	(31)
Other Electric Revenue	14	16	(2)
Total Operating Revenue	$1,202	$1,198	$ 4

The table above shows the amount of Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to ACE's customers within its service territory at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, and revenue in the form of transmission enhancement credits.

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

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$190	$170	$ 20
Commercial and industrial	148	132	16
Transmission and other	91	90	1
Total Regulated T&D Electric Revenue	$429	$392	$ 37

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	4,214	4,357	(143)
Commercial and industrial	4,969	5,090	(121)
Transmission and other	48	48	—
Total Regulated T&D Electric Sales	9,231	9,495	(264)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	478	479	(1)
Commercial and industrial	66	65	1
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	545	545	—

Regulated T&D Electric Revenue increased by $37 million primarily due to:

- An increase of $39 million due to distribution rate increases effective November 2012 and July 2013, and a customer charge rate increase effective November 2012.
- An increase of $6 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).
- An increase of $2 million in transmission revenue associated with the change in FERC formula rate true-ups.

The aggregate amount of these increases was partially offset by:

- A decrease of $6 million due to lower non-weather related average residential and commercial customer usage.
- A decrease of $3 million due to lower sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.
- A decrease of $1 million in transmission revenue primarily attributable to a peak-load rate decrease effective January 2013.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$425	$482	$ (57)
Commercial and industrial	206	215	(9)
Other	128	93	35
Total Default Electricity Supply Revenue	$759	$790	$ (31)

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

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	3,335	3,574	(239)
Commercial and industrial	1,037	1,216	(179)
Other	14	19	(5)
Total Default Electricity Supply Sales	4,386	4,809	(423)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	393	390	3
Commercial and industrial	43	45	(2)
Other	—	—	—
Total Default Electricity Supply Customers	436	435	1

Default Electricity Supply Revenue decreased by $31 million primarily due to:

- A decrease of $38 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $14 million due to lower non-weather related average residential and commercial customer usage.
- A decrease of $8 million as a result of lower Default Electricity Supply rates, primarily due to a Basic Generation Service rate decrease that became effective June 2013, partially offset by a Non-utility Generation Charge rate increase that became effective June 2013.
- A decrease of $6 million due to lower sales, primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

The aggregate amount of these decreases was partially offset by an increase of $36 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.

For the years ended December 31, 2013 and 2012, the percentages of ACE's total distribution sales that are derived from customers receiving Default Electricity Supply are 48% and 51%, respectively.

<u>Operating Expenses</u>

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 $43 million to $660 million in 2013 from $703 million in 2012 primarily due to:

- A decrease of $35 million primarily due to customer migration to competitive suppliers.
- A decrease of $5 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $3 million due to lower electricity sales, primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $9 million to $230 million in 2013 from $239 million in 2012 primarily due to:

- A decrease of $5 million in other storm restoration costs.
- A decrease of $2 million in bad debt expense that is deferred and recoverable.
- A decrease of $1 million associated with lower maintenance costs.

Other Operation and Maintenance expense also includes the effects of 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Costs associated with derecho storm (June 2012)	$ —	$ 14	$ (14)
Regulatory asset established for future recovery of derecho storm costs	—	(14)	14
Costs associated with Hurricane Sandy (October 2012)	—	13	(13)
Regulatory asset established for future recovery of Hurricane Sandy costs	—	(13)	13
Total incremental major storm restoration costs	$ —	$ —	$ —

- During 2012, ACE incurred incremental storm restoration costs of $14 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. ACE's stipulation of settlement approved by the NJBPU in June 2013, provides for recovery of these costs over a three-year period.
- During the fourth quarter of 2012, ACE incurred incremental storm restoration costs of $13 million associated with Hurricane Sandy 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. ACE's stipulation of settlement approved by the NJBPU in June 2013 provides for recovery of these costs over a three-year period.

Depreciation and Amortization

Depreciation and Amortization expense increased by $12 million to $136 million in 2013 from $124 million in 2012 primarily due to:

- An increase of $7 million in amortization of major storm costs.
- An increase of $6 million in amortization due to the expiration of the excess depreciation reserve regulatory liability in August 2013.

Other Taxes

Other Taxes decreased by $4 million to $14 million in 2013 from $18 million in 2012. The decrease was primarily due to decreased Transitional Energy Facility Assessment taxes due to a rate decrease effective January 2013 (partially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Deferred Electric Service Costs

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

Deferred Electric Service Costs increased by $31 million to an expense of $26 million in 2013 as compared to an expense reduction of $5 million in 2012, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Program revenue rates and lower electricity supply costs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $1 million to a net expense of $67 million in 2013 from a net expense of $66 million in 2012 primarily due to lower income related to AFUDC that is applied to capital projects.

Income Tax Expense

ACE's consolidated income tax expense increased by $1 million to $19 million in 2013 from $18 million in 2012. ACE's consolidated effective income tax rates for the years ended December 31, 2013 and 2012 were 27.5% and 34.0%, respectively. The change in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions. In the first quarter of 2013, ACE recorded an interest benefit of $6 million as discussed further below. In the first quarter of 2012, ACE recorded an interest benefit as a result of the effective settlement with the IRS with respect to the methodology used historically to calculate deductible mixed service costs.

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

Capital Requirements

Sources of Capital

ACE has a range of capital sources available, in addition to internally generated funds, to meet its long-term and short-term funding needs. The sources of long-term funding include the issuance of mortgage bonds and other debt securities and bank financings, as well as preferred stock. Proceeds from long-term financings are used primarily to fund long-term capital requirements, such as capital expenditures, and to repay or refinance existing indebtedness. ACE traditionally has used a number of sources to fulfill medium- and short-term funding needs, including commercial paper, medium- and short-term notes, bank lines of credit, and under certain circumstances, borrowings under the PHI money pool. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements. ACE's ability to generate funds from its operations and to access the capital and credit markets is subject to risks and uncertainties. Volatile and deteriorating financial market conditions, diminished liquidity and tightening credit may affect access to certain of ACE's potential funding sources.

Debt Securities

ACE has a Mortgage and Deed of Trust (the Mortgage) under which it issues First Mortgage Bonds. First Mortgage Bonds issued under the Mortgage are secured by a lien on substantially all of ACE's property, plant and equipment, except for such property excluded from the lien of the Mortgage. The principal amount of First Mortgage Bonds that ACE may issue under the Mortgage is limited by the principal amount of retired First Mortgage Bonds and 65% of the lesser of the cost or fair value of new property additions that have not been used as the basis for the issuance of additional First Mortgage Bonds. ACE also has an indenture under which it issues senior notes secured by First Mortgage Bonds and an indenture under which it can issue unsecured debt securities, including VRDBs. To fund the construction of pollution control facilities, ACE also has from time to time raised capital through tax-exempt bonds, including tax-exempt VRDBs, issued by a municipality, the proceeds of which are loaned to ACE by the municipality.

Information concerning the principal amount and terms of ACE's outstanding First Mortgage Bonds, senior notes and tax-exempt bonds issued for the benefit of ACE, as of December 31, 2013, is set forth in Note (9), "Debt," to the consolidated financial statements of ACE.

Bank Financing

As further discussed in Note (9), "Debt," to the consolidated financial statements of ACE, ACE is a borrower under a $1.5 billion unsecured syndicated credit facility, along with PHI, Pepco and DPL, which expires in August 2018. This credit facility provides for ACE's liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting its commercial paper program. ACE's credit limit under the facility is the lesser of $250 million and the maximum amount of short-term debt ACE is permitted to have outstanding by its regulatory authorities. The short-term borrowing limit established by the NJBPU for ACE is $350 million.

Commercial Paper Program

ACE maintains an ongoing commercial paper program to address its short-term liquidity needs. As of December 31, 2013, the maximum capacity available under the program was $250 million, subject to available borrowing capacity under the credit facility.

ACE had $120 million of commercial paper outstanding at December 31, 2013. The weighted average interest rate for commercial paper issued by ACE during 2013 was 0.31% and the weighted average maturity of all commercial paper issued by ACE during 2013 was four days.

Money Pool

ACE participates in the money pool operated by PHI under authorization received from the NJBPU. The money pool is an unsecured cash management mechanism used by PHI and eligible subsidiaries to manage their short-term investment and borrowing requirements. PHI may invest in, but not borrow from, the money pool. Eligible subsidiaries with surplus cash may deposit those funds in the money pool. Deposits in the money pool are guaranteed by PHI. Eligible subsidiaries with cash requirements may borrow from the money pool. Depositors in the money pool receive, and borrowers from the money pool pay, an interest rate based primarily on PHI's short-term borrowing rate. PHI deposits funds in the money pool to the extent that the pool has insufficient funds to meet the borrowing needs of its participants, which may require PHI to borrow funds for deposit from external sources. By regulatory order, the NJBPU has restricted ACE's participation in the PHI money pool. ACE may not invest in the money pool, but may borrow from it if the rates are lower than the rates at which ACE could borrow funds externally.

Preferred Stock

Under its Certificate of Incorporation, ACE is authorized to issue and have outstanding up to (i) 799,979 shares of Cumulative Preferred Stock, (ii) 2 million shares of No Par Preferred Stock and (iii) 3 million shares of Preference Stock, each such type of preferred stock having such terms and conditions as are set forth in or authorized by the Certificate of Incorporation. As of December 31, 2013 and 2012, ACE had no shares of preferred stock outstanding.

Regulatory Restrictions on Financing Activities

ACE's long-term and short-term (consisting of debt instruments with a maturity of one year or less) financing activities are subject to authorization by the NJBPU. Through its periodic filings with the NJBPU, ACE generally maintains standing authority sufficient to cover its projected financing needs over a multi-year period. ACE's long-term and short-term financing activities do not require FERC approval.

State corporate laws impose limitations on the funds that can be used to pay dividends. In addition, ACE must obtain the approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%. As of December 31, 2013, ACE complied with this requirement without the need to seek approval of the NJBPU.

Capital Expenditures

ACE's capital expenditures for the year ended December 31, 2013 were $261 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's projected capital expenditures for the five-year period from 2014 through 2018 are summarized below. ACE expects to fund these expenditures through internally generated cash, external financing and capital contributions from PHI.

	For the Year Ended December 31,					
	2014	**2015**	**2016**	**2017**	**2018**	**Total**
	(millions of dollars)					
ACE						
Distribution	$107	$ 78	$137	$128	$124	$ 574
Distribution – Smart Grid (AMI)	—	—	—	—	8	8
Transmission	109	128	98	85	56	476
Other	25	16	39	39	22	141
Total ACE	$241	$222	$274	$252	$210	$1,199

Transmission and Distribution

The projected capital expenditures listed in the table for distribution (other than the smart grid) and transmission are primarily for facility replacements and upgrades to accommodate customer growth and service reliability, including continued capital expenditures for reliability enhancement efforts.

DOE Capital Reimbursement Awards

During 2009, the DOE announced a $168 million award to PHI under the American Recovery and Reinvestment Act of 2009 for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure, of which $19 million was for ACE's service territory.

During 2010, ACE and the DOE signed agreements formalizing ACE's $19 million share of the $168 million award. Of the $19 million, $12 million is being used for the smart grid and other capital expenditures of ACE. The remaining $7 million is being used to offset incremental expenditures associated with direct load control and other programs. During 2013, ACE received award payments of $4 million. The cumulative award payments received by ACE as of December 31, 2013, were $17 million.

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

Pension and Other Postretirement Benefit Plans

ACE participates in pension and OPEB plans sponsored by PHI for its employees. ACE contributed $30 million to the PHI Retirement Plan during each of 2013 and 2012. In 2013 and 2012, ACE contributed $6 million and $7 million, respectively, to the other postretirement benefit plan.

Item 7A. 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, Executive Vice President (Power Delivery), Chief Financial Officer, General Counsel, Chief Information Officer and other senior executives. The CRMC monitors interest rate fluctuation, commodity price fluctuation, and 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," and Note (13), "Derivative Instruments and Hedging Activities," of the consolidated financial statements of PHI.

Pepco Holdings, Inc.

Interest Rate Risk

Pepco Holdings and its subsidiaries' variable or floating rate debt is subject to the risk of fluctuating interest rates in the normal course of business. Pepco Holdings manages interest rate risk through the use of fixed and, to a lesser extent, variable rate debt. The effect of a hypothetical 10% change in interest rates on the annual interest costs for short-term and variable rate debt was less than $1 million as of December 31, 2013.

Potomac Electric Power Company

Interest Rate Risk

Pepco's debt is subject to the risk of fluctuating interest rates in the normal course of business. Pepco manages interest rate risk through the use of fixed and, to a lesser extent, variable rate debt. The effect of a hypothetical 10% change in interest rates on the annual interest costs for short-term debt and variable rate debt was less than $1 million as of December 31, 2013.

Delmarva Power & Light Company

Commodity Price Risk

DPL uses derivative instruments (for example, forward contracts, futures, swaps, and exchange-traded and over-the-counter options) primarily to reduce natural gas commodity price volatility. DPL also manages commodity risk with capacity contracts that do not meet the definition of derivatives. The primary goal of these activities is to reduce the exposure of its regulated retail natural gas customers to natural gas price spikes. All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all gains and losses on the natural gas hedging activity, are fully recoverable through the GCR clause included in DPL's natural gas tariff rates approved by the DPSC and are deferred until recovered. At December 31, 2013, after the effects of cash collateral and netting of derivative assets and liabilities available to be offset under master netting arrangements, DPL had no net derivative assets or liabilities. At December 31, 2012, after the effects of cash collateral and netting of derivative assets and liabilities available to be offset under master netting arrangements, DPL had a net derivative liability of $4 million, offset by a $4 million regulatory asset.

Interest Rate Risk

DPL's debt is subject to the risk of fluctuating interest rates in the normal course of business. DPL manages interest rate risk through the use of fixed and, to a lesser extent, variable rate debt. The effect of a hypothetical 10% change in interest rates on the annual interest costs for short-term debt and variable rate debt was less than $1 million as of December 31, 2013.

Atlantic City Electric Company

Interest Rate Risk

ACE's debt is subject to the risk of fluctuating interest rates in the normal course of business. ACE manages interest rate risk through the use of fixed and, to a lesser extent, variable rate debt. The effect of a hypothetical 10% change in interest rates on the annual interest costs for short-term debt and variable rate debt was less than $1 million as of December 31, 2013.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

Management's Report on Internal Control over Financial Reporting

The management of Pepco Holdings, Inc. (Pepco Holdings) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management of Pepco Holdings assessed Pepco Holdings' internal control over financial reporting as of December 31, 2013 based on the framework in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment, the management of Pepco Holdings concluded that Pepco Holdings' internal control over financial reporting was effective as of December 31, 2013.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the consolidated financial statements of Pepco Holdings included in this Annual Report on Form 10-K, has also issued its attestation report on the effectiveness of Pepco Holdings' internal control over financial reporting, which is included herein.

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of
Pepco Holdings, Inc.

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Pepco Holdings, Inc. and its subsidiaries at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

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

For the Year Ended December 31,	2013	2012	2011
	(millions of dollars, except per share data)		
Operating Revenue	$ 4,666	$ 4,625	$ 4,964
Operating Expenses			
Fuel and purchased energy	2,070	2,123	2,537
Other services cost of sales	146	170	172
Other operation and maintenance	851	898	889
Depreciation and amortization	473	454	425
Other taxes	428	432	451
Deferred electric service costs	26	(5)	(63)
Impairment losses	4	12	—
Total Operating Expenses	3,998	4,084	4,411
Operating Income	668	541	553
Other Income (Expenses)			
Interest and dividend income	—	1	1
Interest expense	(273)	(256)	(242)
Gain (loss) from equity investments	2	1	(3)
Impairment losses	—	(1)	(5)
Other income	32	35	32
Total Other Expenses	(239)	(220)	(217)
Income from Continuing Operations Before Income Tax Expense	429	321	336
Income Tax Expense Related to Continuing Operations	319	103	114
Net Income from Continuing Operations	110	218	222
(Loss) Income from Discontinued Operations, net of Income Taxes	(322)	67	35
Net (Loss) Income	$ (212)	$ 285	$ 257
Basic Share Information			
Weighted average shares outstanding—Basic (millions)	246	229	226
Earnings per share of common stock from Continuing Operations—Basic	$ 0.45	$ 0.95	$ 0.98
(Loss) earnings per share of common stock from Discontinued Operations—Basic	(1.31)	0.30	0.16
(Loss) earnings per share—Basic	$ (0.86)	$ 1.25	$ 1.14
Diluted Share Information			
Weighted average shares outstanding—Diluted (millions)	246	230	226
Earnings per share of common stock from Continuing Operations—Diluted	$ 0.45	$ 0.95	$ 0.98
(Loss) earnings per share of common stock from Discontinued Operations—Diluted	(1.31)	0.29	0.16
(Loss) earnings per share—Diluted	$ (0.86)	$ 1.24	$ 1.14

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

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

For the Year Ended December 31,	2013	2012	2011
	(millions of dollars)		
Net (Loss) Income	$(212)	$285	$257
Other Comprehensive Income (Loss) from Continuing Operations			
Losses on treasury rate locks reclassified into income	1	—	1
Pension and other postretirement benefit plans	13	(14)	(11)
Other comprehensive income (loss), before income taxes	14	(14)	(10)
Income tax expense (benefit) related to other comprehensive income	6	(6)	(4)
Other comprehensive income (loss) from continuing operations, net of income taxes	8	(8)	(6)
Other Comprehensive Income from Discontinued Operations, Net of Income Taxes	6	23	49
Comprehensive (Loss) Income	$(198)	$300	$300

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

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS	December 31, 2013	December 31, 2012
	(millions of dollars)	
CURRENT ASSETS		
Cash and cash equivalents	$ 23	$ 25
Restricted cash equivalents	13	10
Accounts receivable, less allowance for uncollectible accounts of $38 million and $34 million, respectively	835	804
Inventories	148	153
Prepayments of income taxes	40	59
Deferred income tax assets, net	51	28
Income taxes receivable	234	69
Prepaid expenses and other	53	81
Assets held for disposition	1	38
Total Current Assets	1,398	1,267
OTHER ASSETS		
Goodwill	1,407	1,407
Regulatory assets	2,087	2,614
Income taxes receivable	67	217
Restricted cash equivalents	14	17
Assets and accrued interest related to uncertain tax positions	8	18
Derivative assets	—	8
Other	163	163
Assets held for disposition	—	1,237
Total Other Assets	3,746	5,681
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	14,567	13,625
Accumulated depreciation	(4,863)	(4,779)
Net Property, Plant and Equipment	9,704	8,846
TOTAL ASSETS	$ 14,848	$ 15,794

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

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

LIABILITIES AND EQUITY	December 31, 2013	December 31, 2012
	(millions of dollars, except shares)	
CURRENT LIABILITIES		
Short-term debt	$ 565	$ 965
Current portion of long-term debt and project funding	446	569
Accounts payable	215	196
Accrued liabilities	301	357
Capital lease obligations due within one year	9	8
Taxes accrued	56	75
Interest accrued	47	47
Liabilities and accrued interest related to uncertain tax positions	397	9
Derivative liabilities	—	4
Other	276	272
Liabilities associated with assets held for disposition	1	41
Total Current Liabilities	2,313	2,543
DEFERRED CREDITS		
Regulatory liabilities	399	501
Deferred income tax liabilities, net	2,928	3,208
Investment tax credits	17	20
Pension benefit obligation	116	449
Other postretirement benefit obligations	206	454
Liabilities and accrued interest related to uncertain tax positions	28	15
Derivative liabilities	—	11
Other	189	191
Liabilities associated with assets held for disposition	—	2
Total Deferred Credits	3,883	4,851
OTHER LONG-TERM LIABILITIES		
Long-term debt	4,053	3,648
Transition bonds issued by ACE Funding	214	256
Long-term project funding	10	12
Capital lease obligations	60	70
Total Other Long-Term Liabilities	4,337	3,986
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
EQUITY		
Common stock, $.01 par value— 400,000,000 shares authorized, 250,324,898 and 230,015,427 shares outstanding, respectively	3	2
Premium on stock and other capital contributions	3,751	3,383
Accumulated other comprehensive loss	(34)	(48)
Retained earnings	595	1,077
Total Equity	4,315	4,414
TOTAL LIABILITIES AND EQUITY	$ 14,848	$ 15,794

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

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

For the Year Ended December 31,	2013	2012	2011
		(millions of dollars)	
OPERATING ACTIVITIES			
Net (loss) income	$ (212)	$ 285	$ 257
Loss (income) from discontinued operations, net of income taxes	322	(67)	(35)
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	473	454	425
Deferred income taxes	458	312	178
Losses on treasury rate locks reclassified into income	1	—	1
Impairment losses	4	12	—
Other	(13)	(15)	(16)
Changes in:			
Accounts receivable	(46)	(2)	56
Inventories	5	(28)	(8)
Prepaid expenses	17	(12)	(4)
Regulatory assets and liabilities, net	(121)	(174)	(148)
Accounts payable and accrued liabilities	1	43	(53)
Pension contributions	(120)	(200)	(110)
Pension benefit obligation, excluding contributions	65	65	53
Cash collateral related to derivative activities	31	88	9
Income tax-related prepayments, receivables and payables	(182)	(160)	(27)
Advanced payment made to taxing authority	(242)	—	—
Other assets and liabilities	9	16	43
Net current assets held for disposition or sale	47	(25)	65
Net Cash From Operating Activities	497	592	686
INVESTING ACTIVITIES			
Investment in property, plant and equipment	(1,310)	(1,216)	(941)
Department of Energy capital reimbursement awards received	22	40	52
Changes in restricted cash equivalents	1	(1)	(10)
Net other investing activities	3	6	(9)
Proceeds from disposal of assets held for disposition	873	202	161
Net Cash Used By Investing Activities	(411)	(969)	(747)
FINANCING ACTIVITIES			
Dividends paid on common stock	(270)	(248)	(244)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	50	51	47
Issuances of common stock	324	—	—
Redemption of preferred stock of subsidiaries	—	—	(6)
Issuances of long-term debt	800	450	235
Reacquisitions of long-term debt	(558)	(176)	(70)
(Repayments) issuances of short-term debt, net	(200)	33	198
Issuances of term loans	250	200	—
Repayments of term loans	(450)	—	—
Cost of issuances	(23)	(9)	(10)
Net other financing activities	(11)	(8)	(1)
Net Cash (Used By) From Financing Activities	(88)	293	149
Net (Decrease) Increase In Cash and Cash Equivalents	(2)	(84)	88
Cash and Cash Equivalents at Beginning of Year	25	109	21
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 23	$ 25	$ 109
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid for interest (net of capitalized interest of $7 million, $8 million and $11 million, respectively)	$ 260	$ 253	$ 240
Cash paid for income taxes	228	—	4
Non-cash activities:			
Reclassification of property, plant and equipment to regulatory assets	—	88	—
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 STATEMENTS OF EQUITY

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total
Balance as of December 31, 2010	225,082,252	$ 2	$ 3,275	$ (106)	$ 1,027	$4,198
Net Income	—	—	—	—	257	257
Other comprehensive income	—	—	—	43	—	43
Dividends on common stock ($1.08 per share)	—	—	—	—	(244)	(244)
Issuance of common stock:						
Original issue shares, net	854,124	—	17	—	—	17
Shareholder DRP original shares	1,563,814	—	30	—	—	30
Net activity related to stock-based awards	—	—	3	—	—	3
Balance as of December 31, 2011	227,500,190	2	3,325	(63)	1,040	4,304
Net Income	—	—	—	—	285	285
Other comprehensive income	—	—	—	15	—	15
Dividends on common stock ($1.08 per share)	—	—	—	—	(248)	(248)
Issuance of common stock:						
Original issue shares, net	854,060	—	19	—	—	19
Shareholder DRP original shares	1,661,177	—	32	—	—	32
Net activity related to stock-based awards	—	—	7	—	—	7
Balance as of December 31, 2012	230,015,427	2	3,383	(48)	1,077	4,414
Net Loss	—	—	—	—	(212)	(212)
Other comprehensive income	—	—	—	14	—	14
Dividends on common stock ($1.08 per share)	—	—	—	—	(270)	(270)
Issuance of common stock:						
Original issue shares, net	18,734,128	1	331	—	—	332
Shareholder DRP original shares	1,575,343	—	30	—	—	30
Net activity related to stock-based awards	—	—	7	—	—	7
Balance as of December 31, 2013	250,324,898	$ 3	$ 3,751	$ (34)	$ 595	$4,315

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PEPCO HOLDINGS, INC.

(1) ORGANIZATION

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

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

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

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

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

Power Delivery

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

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

Pepco Energy Services

Pepco Energy Services is engaged in the following businesses:

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

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. Pepco Energy Services placed the facilities into an idle condition termed a "cold closure." A cold closure requires that the utility service be disconnected so that the facilities are no longer operable and require only essential maintenance until they are completely decommissioned. During the third quarter of 2013, Pepco Energy Services determined that it would be more cost effective to pursue the demolition of the Benning Road generation facility and realization of the scrap metal salvage value of the facility instead of maintaining cold closure status. As a result of this change in intent, Pepco Energy Services reduced its asset retirement obligation related to the facility by $2 million. The demolition of the facility commenced in the fourth quarter of 2013 and is expected to be completed by the end of 2014. Pepco Energy Services will recognize the salvage proceeds associated with the scrap metals at the facility as realized.

Other Non-Regulated

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

Discontinued Operations

Cross-Border Energy Lease Investments

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

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

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

Pepco Energy Services

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

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

(2) SIGNIFICANT ACCOUNTING POLICIES

Consolidation Policy

The accompanying consolidated financial statements include the accounts of Pepco Holdings and its wholly owned subsidiaries. All material intercompany balances and transactions between subsidiaries have been eliminated. Pepco Holdings uses the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies in which it holds an interest and can exercise significant influence over the operations and policies of the entity. Certain transmission and other facilities currently held, are consolidated in proportion to PHI's percentage interest in the facility.

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 FASB ASC 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests. See Note (16), "Variable Interest Entities," for additional information.

Use of Estimates

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

Significant matters that involve the use of estimates include the assessment of contingencies, the calculation of future cash flows and fair value amounts for use in asset and goodwill impairment calculations, fair value calculations for derivative instruments, pension and other postretirement benefit assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of loss contingency liabilities for general and auto liability claims, accrual of interest related to income taxes, the recognition of lease income and income tax benefits for investments in finance leases held in trust associated with PHI's portfolio of cross-border energy lease investments (see Note (19), "Discontinued Operations – Cross-Border Energy Lease Investments"), and income tax provisions and reserves. Additionally, PHI is subject to legal, regulatory and other proceedings and claims that arise in the ordinary course of its business. PHI records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Revenue Recognition

Regulated Revenue

Power Delivery recognizes revenue upon distribution of electricity and natural gas to its customers, including unbilled revenue for services rendered but not yet billed. PHI's unbilled revenue was $177 million and $182 million as of December 31, 2013 and 2012, respectively, and these amounts are included in Accounts receivable. PHI's utility subsidiaries calculate unbilled revenue using an output-based methodology. This methodology is based on the supply of electricity or natural gas intended for distribution to customers. The unbilled revenue process requires management to make assumptions and judgments about input factors such as customer sales mix, temperature and estimated line losses (estimates of electricity and natural gas expected to be lost in the process of its transmission and distribution to customers). The assumptions and judgments are inherently uncertain and susceptible to change from period to period, and if the actual results differ from the projected results, the impact could be material.

Taxes related to the consumption of electricity and natural gas by the utility customers, such as fuel, energy, or other similar taxes, are components of the tariff rates charged by PHI's utility subsidiaries and, as such, are billed to customers and recorded in Operating revenue. Accruals for the remittance of these taxes are recorded in Other taxes.

Pepco Energy Services Revenue

Revenue for Pepco Energy Services' energy savings performance construction business is recognized using the percentage-of-completion method which recognizes revenue as work is completed on its contracts. Revenues from its operation and maintenance activities and measurement and verification activities in its energy savings business are recognized when earned.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in PHI's gross revenues were $346 million, $356 million and $378 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Accounting for Derivatives

PHI and its subsidiaries may use derivative instruments primarily to manage risk associated with commodity prices and interest rates. Risk management policies are determined by PHI's Corporate Risk Management Committee (CRMC). The CRMC monitors interest rate fluctuation, commodity price fluctuation and credit risk exposure, and sets risk management policies that establish limits on unhedged risk.

PHI accounts for its derivative activities in accordance with FASB guidance on derivatives and hedging. Derivatives are recorded on the consolidated balance sheets as Derivative assets or Derivative liabilities and measured at fair value.

Changes in the fair value of derivatives held by DPL that do not qualify for hedge accounting or are not designated as hedges are presented on the consolidated statements of (loss) income as Fuel and purchased energy expense or Operating revenue, respectively. Changes in the fair value of derivatives held by DPL are deferred as regulatory assets or liabilities under the accounting guidance for regulated operations.

The gain or loss on a derivative that qualifies as a cash flow hedge of an exposure to variable cash flows of a forecasted transaction is initially recorded in accumulated other comprehensive loss (AOCL) (a separate component of equity) to the extent that the hedge is effective and is subsequently reclassified into earnings, in the same category as the item being hedged, when the gain or loss from the forecasted transaction occurs. If it is probable that a forecasted transaction will not occur, the deferred gain or loss in AOCL is immediately reclassified to earnings. Gains or losses related to any ineffective portion of cash flow hedges are also recognized in earnings immediately.

Changes in the fair value of derivatives designated as fair value hedges, as well as changes in the fair value of the hedged asset, liability or firm commitment, are recorded in the consolidated statements of (loss) income.

The impact of derivatives that are marked to market through current earnings, the ineffective portion of cash flow hedges, and the portion of fair value hedges that flows to current earnings are presented on a net basis in the consolidated statements of (loss) income as Operating revenue or as Fuel and purchased energy expense. When a hedging gain or loss is realized, it is presented on a net basis in the same line item as the underlying item being hedged. Unrealized derivative gains and losses are presented gross on the consolidated balance sheets except where contractual netting agreements are in place with individual counterparties.

The fair value of derivatives is determined using quoted exchange prices where available. For instruments that are not traded on an exchange, pricing services and external broker quotes may also be used to determine fair value. For some custom and complex instruments, internal models use market-based information when external broker quotes are not available. For certain long-dated instruments, broker or exchange data are extrapolated, or capacity prices are forecasted, for future periods where information is limited. Models are also used to estimate volumes for certain transactions.

PHI may enter into master netting arrangements to mitigate credit risk related to its derivatives. Under FASB guidance on offsetting of balance sheet accounts (ASC 210-20), amounts recognized for derivative assets and liabilities and the fair value amounts recognized for any related collateral positions executed with the same counterparty under such master netting agreements are offset.

See Note (13), "Derivative Instruments and Hedging Activities," for more information about the types of derivatives employed by PHI, the components of any unrealized and realized gains and losses and Note (14), "Fair Value Disclosures," for the methodologies used to value them.

Stock-Based Compensation

PHI recognizes compensation expense for stock-based awards, modifications or cancellations based on the grant-date fair value. Compensation expense is recognized over the requisite service period. A deferred tax asset and deferred tax benefit are also recognized concurrently with compensation expense for the tax effect of the deduction of stock options and restricted stock awards, which are deductible only upon exercise and vesting.

Historically, PHI's compensation awards had included both time-based restricted stock awards that vest over a three-year service period and performance-based restricted stock units that were earned based on performance over a three-year period. Beginning in 2011, stock-based compensation awards have been granted primarily in the form of restricted stock units. The compensation expense associated with these awards is calculated based on the estimated fair value of the awards at the grant date and is recognized over the service or performance period.

PHI estimated the fair value of stock option awards on the date of grant using the Black-Scholes-Merton option pricing model. This model used assumptions related to expected term, expected volatility, expected dividend yield, and the risk-free interest rate. PHI used historical data to estimate award exercises and employee terminations within the valuation model; groups of employees that have similar historical exercise behavior were considered separately for valuation purposes.

PHI's current policy is to issue new shares to satisfy vested awards of restricted stock units.

Income Taxes

PHI and the majority of its subsidiaries file a consolidated federal income tax return. Federal income taxes are allocated among PHI and the subsidiaries included in its consolidated group pursuant to a written tax sharing agreement, which was approved by the Securities and Exchange Commission (SEC) in 2002 in connection with the establishment of PHI as a public utility holding company. Under this tax sharing agreement, PHI's consolidated federal income tax liability is allocated based upon PHI's and its subsidiaries' separate taxable income or loss amounts.

The consolidated financial statements include current and deferred income taxes. Current income taxes represent the amount of tax expected to be reported on PHI's and its subsidiaries' federal and state income tax returns. Deferred income tax assets and liabilities represent the tax effects of temporary differences between the financial statement basis and tax basis of existing assets and liabilities, and they are measured using presently enacted tax rates. See Note (11), "Income Taxes," for a listing of primary deferred tax assets and liabilities. The portions of Pepco's, DPL's and ACE's deferred tax liabilities applicable to their utility operations that have not been recovered from utility customers represent income taxes recoverable in the future and are included in Regulatory Assets on the consolidated balance sheets. See Note (7), "Regulatory Matters – Regulatory Assets and Regulatory Liabilities," for additional information.

PHI recognizes interest on underpayments and overpayments of income taxes, interest on uncertain tax positions and tax-related penalties in income tax expense. Deferred income tax expense generally represents the net change during the reporting period in the net deferred tax liability and deferred recoverable income taxes.

Investment tax credits are amortized to income over the useful lives of the related property.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, cash invested in money market funds and commercial paper held with original maturities of three months or less.

Restricted Cash Equivalents

The Restricted cash equivalents included in Current assets and the Restricted cash equivalents included in Other assets consist of (i) cash held as collateral that is restricted from use for general corporate purposes and (ii) cash equivalents that are specifically segregated based on management's intent to use such cash equivalents for a particular purpose. The classification as current or non-current conforms to the classification of the related liabilities.

Accounts Receivable and Allowance for Uncollectible Accounts

PHI's Accounts receivable balances primarily consist of customer accounts receivable arising from the sale of goods and services to customers within PHI's service territories, other accounts receivable, and accrued unbilled revenue. Accrued unbilled revenue represents revenue earned in the current period but not billed to the customer until a future date (usually within one month after the receivable is recorded).

PHI maintains an allowance for uncollectible accounts and changes in the allowance are recorded as an adjustment to Other operation and maintenance expense in the consolidated statements of (loss) income. PHI determines the amount of the allowance based on specific identification of material amounts at risk by customer and maintains a reserve based on its historical collection experience. The adequacy of this allowance is assessed on a quarterly basis by evaluating all known factors, such as the aging of the receivables, historical collection experience, the economic and competitive environment and changes in the creditworthiness of its customers. Accounts receivable are written off in the period in which the receivable is deemed uncollectible and collection efforts have been exhausted. Recoveries of Accounts receivable previously written off are recorded when it is probable they will be recovered. Although PHI believes its allowance is adequate, it cannot anticipate with any certainty the changes in the financial condition of its customers. As a result, PHI records adjustments to the allowance for uncollectible accounts in the period in which the new information that requires an adjustment to the reserve becomes known.

Inventories

Inventory is valued at the lower of cost or market value. Included in Inventories are generation, transmission and distribution materials and supplies, natural gas and fuel oil.

PHI utilizes the weighted average cost method of accounting for inventory items. Under this method, an average price is determined for the quantity of units acquired at each price level and is applied to the ending quantity to calculate the total ending inventory balance. Materials and supplies are recorded in Inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

The cost of natural gas, including transportation costs, is included in Inventory when purchased and charged to Fuel and Purchased Energy expense when used.

Goodwill

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

Regulatory Assets and Regulatory Liabilities

The operations of Pepco are regulated by the District of Columbia Public Service Commission (DCPSC) and the Maryland Public Service Commission (MPSC). The operations of DPL are regulated by the Delaware Public Service Commission (DPSC) and the MPSC. DPL's interstate transportation and wholesale sale of natural gas are regulated by the Federal Energy Regulatory Commission (FERC). The operations of ACE are regulated by the New Jersey Board of Public Utilities (NJBPU). The transmission of electricity by Pepco, DPL and ACE is regulated by FERC.

The FASB guidance on regulated operations (ASC 980) applies to Power Delivery. It allows regulated entities, in appropriate circumstances, to defer the income statement impact of certain costs that are expected to be recovered in future rates through the establishment of regulatory assets and defer certain revenues that are expected to be refunded to customers through the establishment of regulatory liabilities. Management's assessment of the probability of recovery of regulatory assets requires judgment and interpretation of laws, regulatory commission orders and other factors. If management subsequently determines, based on changes in facts or circumstances, that a regulatory asset is not probable of recovery, then the regulatory asset would be eliminated through a charge to earnings.

Effective June 2007, the MPSC approved a bill stabilization adjustment (BSA) mechanism for retail customers of Pepco and DPL. Effective November 2009, the DCPSC approved a BSA for Pepco's retail customers. For customers to whom the BSA applies, Pepco and DPL recognize distribution revenue based on an approved distribution charge per customer. From a revenue recognition standpoint, the BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during that period. Pursuant to this mechanism, Pepco and DPL recognize either (i) a positive adjustment equal to the amount by which revenue from Maryland and the District of Columbia 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 (a Revenue Decoupling Adjustment). A net positive Revenue Decoupling Adjustment is recorded as a regulatory asset and a net negative Revenue Decoupling Adjustment is recorded as a regulatory liability.

Leasing Activities

Pepco Holdings' lease transactions include plant, office space, equipment, software, vehicles and elements of power purchase agreements (PPAs). In accordance with FASB guidance on leases (ASC 840), these leases are classified as either leveraged leases, operating leases or capital leases.

Leveraged Leases

Income from investments in leveraged lease transactions, in which PHI is an equity participant, was accounted for using the financing method. In accordance with the financing method, investments in leased property were recorded as a receivable from the lessee to be recovered through the collection of future rentals. Income was recognized over the life of the lease at a constant rate of return on the positive net investment. Each quarter, PHI reviewed the carrying value of each lease, which included a review of the underlying financial assumptions, the timing and collectibility of cash flows, and the credit quality of the lessee. Changes to the underlying assumptions, if any, were accounted for in accordance with FASB guidance on leases and reflected in the carrying value of the lease effective for the quarter within which they occurred.

Operating Leases

An operating lease in which PHI or a subsidiary is the lessee generally results in a level income statement charge over the term of the lease, reflecting the rental payments required by the lease agreement. If rental payments are not made on a straight-line basis, PHI's policy is to recognize rent expense on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed.

Capital Leases

For ratemaking purposes, capital leases in which PHI or a subsidiary is the lessee are treated as operating leases; therefore, in accordance with FASB guidance on regulated operations (ASC 980), the amortization of the leased asset is based on the recovery of rental payments through customer rates. Investments in equipment under capital leases are stated at cost, less accumulated depreciation. Depreciation is recorded on a straight-line basis over the equipment's estimated useful life.

Arrangements Containing a Lease

PPAs contain a lease if the arrangement conveys the right to control the use of property, plant or equipment. If so, PHI determines the appropriate lease accounting classification.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The carrying value of Property, plant and equipment is evaluated for impairment whenever circumstances indicate the carrying value of those assets may not be recoverable. Upon retirement, the cost of regulated property, net of salvage, is charged to Accumulated depreciation. For non-regulated property, the cost and accumulated depreciation of the property, plant and equipment retired or otherwise disposed of are removed from the related accounts and included in the determination of any gain or loss on disposition.

The annual provision for depreciation on electric and natural gas property, plant and equipment is computed on a straight-line basis using composite rates by classes of depreciable property. Accumulated depreciation is charged with the cost of depreciable property retired, less salvage and other recoveries. Non-operating and other property is generally depreciated on a straight-line basis over the useful lives of the assets. The table below provides system-wide composite annual depreciation rates for the years ended December 31, 2013, 2012 and 2011.

	Transmission and Distribution			Generation		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Pepco	2.2%	2.5%	2.6%	—	—	—
DPL	2.6%	2.7%	2.8%	—	—	—
ACE	2.8%	3.0%	3.0%	—	—	—
Pepco Energy Services (a)	—	—	—	0.4%	6.4%	10.2%

(a) Percentages reflect accelerated depreciation of the Benning Road and Buzzard Point generating facilities retired during 2012.

In 2010, subsidiaries of PHI received awards from the U.S. Department of Energy (DOE) under the American Recovery and Reinvestment Act of 2009. Pepco was awarded $149 million from DOE to fund a portion of the costs incurred for the implementation of an advanced metering infrastructure (AMI) system (a system that collects, measures and analyzes energy usage data from advanced digital meters known as smart meters), direct load control, distribution automation and communications infrastructure in its Maryland and District of Columbia service territories. ACE was awarded $19 million from DOE to fund a portion of the costs incurred for the implementation of direct load control, distribution automation and communications infrastructure in its New Jersey service territory. PHI has elected to recognize the award proceeds as a reduction in the carrying value of the assets acquired rather than grant income over the service period.

Long-Lived Asset Impairment Evaluation

PHI evaluates long-lived assets to be held and used, such as generating property and equipment, and real estate, for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. Examples of such events or changes include a significant decrease in the market price of a long-lived asset or a significant adverse change in the manner in which an asset is being used or its physical condition. A long-lived asset to be held and used is written down to its estimated fair value if the expected future undiscounted cash flow from the asset is less than its carrying value.

For long-lived assets held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value including costs to sell.

Capitalized Interest and Allowance for Funds Used During Construction

In accordance with FASB guidance on regulated operations (ASC 980), PHI's utility subsidiaries can capitalize the capital costs of financing the construction of plant and equipment as allowance for funds used during construction (AFUDC). This results in the debt portion of AFUDC being recorded as a reduction of Interest expense and the equity portion of AFUDC being recorded as an increase to Other income in the accompanying consolidated statements of (loss) income.

Pepco Holdings recorded AFUDC for borrowed funds of $7 million, $7 million and $11 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Pepco Holdings recorded amounts for the equity component of AFUDC of $11 million, $14 million and $15 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Amortization of Debt Issuance and Reacquisition Costs

Pepco Holdings defers and amortizes debt issuance costs and long-term debt premiums and discounts over the lives of the respective debt issuances. When PHI utility subsidiaries refinance existing debt or redeem existing debt, any unamortized premiums, discounts and debt issuance costs, as well as debt redemption costs, are classified as Regulatory assets and are amortized over the life of the original or new issue.

Asset Removal Costs

In accordance with FASB guidance, asset removal costs are recorded by PHI utility subsidiaries as Regulatory liabilities. At December 31, 2013 and 2012, $275 million and $324 million, respectively, of asset removal costs are included in Regulatory liabilities in the accompanying consolidated balance sheets.

Pension and Postretirement Benefit Plans

PHI sponsors the PHI Retirement Plan, a non-contributory, defined benefit pension plan that covers substantially all employees of Pepco, DPL, ACE and certain employees of other PHI subsidiaries. PHI also provides supplemental retirement benefits to certain eligible executives and key employees through nonqualified retirement plans and provides certain postretirement health care and life insurance benefits for eligible retired employees. Most employees hired after January 1, 2005 will not have retiree health care coverage.

Net periodic benefit cost is included in Other operation and maintenance expense, net of the portion of the net periodic benefit cost capitalized as part of the cost of labor for internal construction projects. After intercompany allocations, the three utility subsidiaries are responsible for substantially all of the total PHI net periodic benefit cost.

PHI accounts for the PHI Retirement Plan, the nonqualified retirement plans, and the retirement health care and life insurance benefit plans in accordance with FASB guidance on retirement benefits (ASC 715).

See Note (9), "Pension and Other Postretirement Benefits," for additional information.

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 individually or in the aggregate to either the current period or prior period financial results:

Income Tax Expense Related to Continuing Operations

During 2013, Pepco recorded certain adjustments to correct prior period errors related to income taxes. These adjustments resulted from the completion of additional analysis of deferred tax balances and resulted in an increase in Income tax expense of $4 million, for the year ended December 31, 2013.

During 2011, PHI recorded adjustments to correct certain income tax errors related to prior periods associated with the interest on uncertain tax positions. The adjustment resulted in an increase in Income tax expense of $2 million for the year ended December 31, 2011.

Pepco Energy Services Derivative Accounting Adjustment

During 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 a decrease in Loss from discontinued operations, net of income taxes of $1 million for the year ended December 31, 2011.

DPL Operating Revenue Adjustment

During 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 year ended December 31, 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 $11 million for the year ended December 31, 2011.

ACE BGS Deferred Electric Service Costs Adjustments

In 2012, ACE recorded an adjustment to correct errors associated with its calculation of deferred electric service costs. This adjustment resulted in an increase of $3 million to deferred electric service costs, all of which relates to periods prior to 2012.

Revision to Prior Period Financial Statements

PCI Deferred Income Tax Liability Adjustment

Since 1999, PCI had not recorded a deferred tax liability related to a temporary difference between the financial reporting basis and the tax basis of an investment in a wholly owned partnership. In the second quarter of 2013, PHI re-evaluated this accounting treatment and found it to be in error, requiring an adjustment related to prior periods. PHI determined that the cumulative adjustment required, representing a charge to earnings of $32 million, related to a period prior to the year ended December 31, 2009 (the earliest period for which selected consolidated financial data is presented in the table entitled “Selected Financial Data” in Part II, Item 6 of this Annual Report on Form 10-K). Consistent with PHI’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, the accompanying consolidated financial statements reflect the correction of this error as an adjustment to shareholders’ equity for the earliest period presented. The adjustment to correct the error did not affect PHI’s consolidated statements of (loss) income, comprehensive (loss) income and cash flows for each of the three years in the period ended December 31, 2013, and only affected PHI’s reported balances of deferred income tax liabilities and retained earnings as reflected in the consolidated balance sheets as of December 31, 2013 and 2012 and the reported balances of retained earnings and total equity as reflected in the consolidated statements of equity for each of the three years in the period ended December 31, 2013. The adjustment is not considered to be material to PHI’s reported balances of retained earnings and total equity reflected in the PHI consolidated financial statements included in this Annual Report on Form 10-K. The table below illustrates the effects of the revision on reported balances in PHI’s consolidated financial statements.

	As Filed	Adjustment	As Revised
		(millions of dollars)	
December 31, 2012			
Deferred income tax liabilities, net	$3,176	$ 32	$ 3,208
Total deferred credits	4,819(a)	32	4,851
Retained earnings	1,109	(32)	1,077
Total equity	4,446	(32)	4,414
December 31, 2011			
Deferred income tax liabilities, net	$2,863	$ 32	$ 2,895
Total deferred credits	4,549(a)	32	4,581
Retained earnings	1,072	(32)	1,040
Total equity	4,336	(32)	4,304
December 31, 2010			
Retained earnings	$1,059	$ (32)	$ 1,027
Total equity	4,230(b)	(32)	4,198

(a) The amount of total deferred credits differs from the amount orginially reported in PHI’s 2012 Form 10-K due to certain reclassifications.
(b) The amount represents total shareholders’ equity, which excludes a non-controlling interest of $6 million.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

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

Comprehensive Income (ASC 220)

The new disclosure requirements for reclassifications from accumulated other comprehensive income were effective for PHI beginning with its March 31, 2013 consolidated financial statements and required PHI to present additional information about its reclassifications from accumulated other comprehensive income in a single footnote or on the face of its consolidated financial statements. The additional information required to be disclosed includes a presentation of the components of accumulated other comprehensive income that have been reclassified by source (e.g., commodity derivatives), and the income statement line item (e.g., Fuel and purchased energy) affected by the reclassification. PHI has provided the new required disclosures in Note (17), "Accumulated Other Comprehensive Loss."

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, PHI will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. PHI will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between PHI and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements are effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. PHI does not expect this new guidance to have a material impact on its consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with PHI's March 31, 2014 consolidated financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. PHI does not expect this new guidance to have a material impact on its consolidated financial statements.

(5) SEGMENT INFORMATION

Pepco Holdings' management has identified its operating segments at December 31, 2013 as Power Delivery and Pepco Energy Services. In the tables below, the Corporate and Other column is included to reconcile the segment data with consolidated data and includes unallocated Pepco Holdings' (parent company) capital costs, such as financing costs. Through its subsidiary PCI, PHI maintained a portfolio of cross-border energy lease investments. PHI completed the termination of its interests in its cross-border energy lease investments during 2013. As a result, the cross-border energy lease investments, which comprised substantially all of the operations of the former Other Non-Regulated segment, are being accounted for as discontinued operations. The remaining operations of the former Other Non-Regulated segment, which no longer meet the definition of a separate segment for financial reporting purposes, are now included in Corporate and Other. Segment financial information for continuing operations at and for the years ended December 31, 2013, 2012 and 2011, is as follows:

	Year Ended December 31, 2013 (millions of dollars)			
	Power Delivery	**Pepco Energy Services**	**Corporate and Other (a)**	**PHI Consolidated**
Operating Revenue	$ 4,472	$ 203	$ (9)	$ 4,666
Operating Expenses (b)	3,828	201(e)	(31)	3,998
Operating Income	644	2	22	668
Interest Expense	228	1	44	273
Other Income	28	3	3	34
Income Tax Expense (c)	155	1	163 (d)	319
Net Income (Loss) from Continuing Operations	289	3	(182)	110
Total Assets (excluding Assets Held for Disposition)	13,027	335	1,485	14,847
Construction Expenditures	$ 1,194	$ 4	$ 112	$ 1,310

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(10) million for Operating Revenue, $(9) million for Operating Expenses and $(5) million for Interest Expense.

(b) Includes depreciation and amortization expense of $473 million, consisting of $439 million for Power Delivery, $6 million for Pepco Energy Services and $28 million for Corporate and Other.

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

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

(e) Includes pre-tax impairment losses of $4 million ($3 million after-tax) at Pepco Energy Services associated with a landfill gas-fired electric generation facility.

	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	Year Ended December 31, 2012 *(millions of dollars)*			
Operating Revenue	$ 4,378	$ 256(b)	$ (9)	$ 4,625
Operating Expenses (c)	3,847	271(b)(d)	(34)	4,084
Operating Income (Loss)	531	(15)	25	541
Interest Income	1	1	(1)	1
Interest Expense	219	2	35	256
Impairment Losses	—	—	(1)	(1)
Other Income	32	1	3	36
Income Tax Expense (Benefit)	110	(7)	—	103
Net Income (Loss) from Continuing Operations	235	(8)	(9)	218
Total Assets (excluding Assets Held for Disposition)	12,149	342	2,028	14,519
Construction Expenditures	$ 1,168	$ 11	$ 37	$ 1,216

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(11) million for Operating Revenue, $(10) million for Operating Expenses, $(21) million for Interest Income and $(18) million for Interest Expense.

(b) Includes $9 million of intra-company revenues (and associated costs) previously eliminated in consolidation which will continue to be recognized from third parties subsequent to the completion of the wind-down of the Pepco Energy Services' retail electric and natural gas supply businesses.

(c) Includes depreciation and amortization expense of $454 million, consisting of $416 million for Power Delivery, $14 million for Pepco Energy Services and $24 million for Corporate and Other.

(d) Includes impairment losses of $12 million pre-tax ($7 million after-tax) at Pepco Energy Services associated primarily with investments in landfill gas-fired electric generation facilities, and the combustion turbines at Buzzard Point.

	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	Year Ended December 31, 2011 *(millions of dollars)*			
Operating Revenue	$ 4,650	$ 330(b)	$ (16)	$ 4,964
Operating Expenses (c)	4,150	301(b)	(40)	4,411
Operating Income	500	29	24	553
Interest Income	1	1	(1)	1
Interest Expense	208	2	32	242
Impairment Losses	—	—	(5)	(5)
Other Income (Expenses)	29	2	(2)	29
Income Tax Expense (Benefit) (d)	112	8	(6)	114
Net Income (Loss) from Continuing Operations	210	22	(10)	222
Total Assets (excluding Assets Held for Disposition)	11,008	529	1,988	13,525
Construction Expenditures	$ 888	$ 14	$ 39	$ 941

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(16) million for Operating Revenue, $(15) million for Operating Expense, $(22) million for Interest Income and $(22) million for Interest Expense.

(b) Includes $15 million of intra-company revenues (and associated costs) previously eliminated in consolidation which will continue to be recognized from third parties subsequent to the completion of the wind-down of the Pepco Energy Services' retail electric and natural gas supply businesses.

(c) Includes depreciation and amortization expense of $425 million, consisting of $394 million for Power Delivery, $16 million for Pepco Energy Services and $15 million for Corporate and Other.

(d) Includes tax benefits of $14 million for Power Delivery primarily associated with an interest benefit related to federal tax liabilities.

(6) GOODWILL

Substantially all of PHI's goodwill balance as of December 31, 2013 and 2012 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).

In order to estimate the fair value of the Power Delivery reporting unit, PHI uses two valuation techniques: an income approach and a market approach. The income approach estimates fair value based on a discounted future cash flow analysis and a terminal value that is consistent with Power Delivery's long-term view of the business. This approach uses a discount rate based on the estimated weighted average cost of capital (WACC) for the reporting unit. PHI determines the estimated WACC by considering appropriate market-based information for the cost of equity and cost of debt as of the measurement date. The market approach estimates fair value based on a multiple of earnings before interest, taxes, depreciation, and amortization (EBITDA) that management believes is consistent with EBITDA multiples for comparable utilities. PHI has consistently used this valuation technique to estimate the fair value of Power Delivery.

The estimation of fair value is dependent on a number of factors including but not limited to interest rates, growth assumptions, returns on rate base, operating and capital expenditure requirements, and other factors, changes in which could materially affect the results of impairment testing. Assumptions used were consistent with historical experience, including assumptions concerning the recovery of operating costs and capital expenditures and current market-based information. Sensitive, interrelated and uncertain variables that could decrease the estimated fair value of the Power Delivery reporting unit include utility sector market performance, sustained adverse business conditions, changes in forecasted revenues, higher operating and maintenance capital expenditure requirements, a significant increase in the weighted-average cost of capital and other factors.

In addition to estimating the fair value of its Power Delivery reporting unit, PHI estimated the fair value of its other reporting units at November 1, 2013. The sum of the estimated fair values of all reporting units was reconciled to PHI's market capitalization at November 1, 2013 to corroborate PHI's estimates of the fair values of its reporting units. The sum of the estimated fair values of all reporting units exceeded the market capitalization of PHI at November 1, 2013. PHI believes that the excess of the estimated fair value of PHI's reporting units as compared to PHI's market capitalization reflects a control premium that is reasonable when compared to control premiums observed in historical acquisitions in the utility industry and giving consideration to the current economic environment.

As of December 31, 2013 and 2012, PHI's goodwill balance was $1,407 million, which is net of accumulated impairment losses of $18 million.

(7) REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

The components of Pepco Holdings' regulatory asset and liability balances at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Regulatory Assets		
Pension and OPEB costs	$ 667	$1,171
Securitized stranded costs (a)	350	416
Smart Grid costs (a)	251	230
Recoverable income taxes	225	177
Deferred energy supply costs (a)	136	183
Demand-side management costs (a)	125	57
Incremental storm restoration costs (a)	72	89
MAPP abandonment costs (a)	68	88
Deferred debt extinguishment costs (a)	47	53
Recoverable workers' compensation and long-term disability costs	26	31
Deferred losses on gas derivatives	—	4
Other	120	115
Total Regulatory Assets	$2,087	$2,614
Regulatory Liabilities		
Asset removal costs	$ 275	$ 324
Deferred energy supply costs	46	78
Deferred income taxes due to customers	45	45
Deferred gains on gas derivatives	1	—
Excess depreciation reserve	—	11
Other	32	43
Total Regulatory Liabilities	$ 399	$ 501

(a) A return is generally earned on these deferrals.

A description for each category of regulatory assets and regulatory liabilities follows:

Pension and OPEB Costs: Represents unrecognized net actuarial losses and prior service cost (credit) for Pepco Holdings' defined benefit pension and other postretirement benefit (OPEB) plans that are expected to be recovered by Pepco, DPL and ACE in rates. The utilities have historically included these items as a part of its cost of service in its customer rates. This regulatory asset is adjusted at least annually when the funded status of Pepco Holdings' defined benefit pension and OPEB plans are re-measured. See Note (9), "Pension and Other Postretirement Benefits," for more information about the components of the unrecognized pension and OPEB costs.

Securitized Stranded Costs: Certain contract termination payments under a contract between ACE and an unaffiliated non-utility generator (NUG) and costs associated with the regulated operations of ACE's electricity generation business are no longer recoverable through customer rates (collectively referred to as "stranded costs"). The stranded costs are amortized over the life of Transition Bonds issued by Atlantic City Electric Transition Funding LLC (ACE Funding) (Transition Bonds) to securitize the recoverability of these stranded costs. These bonds mature between 2014 and 2023. A customer surcharge is collected by ACE to fund principal and interest payments on the Transition Bonds.

Smart Grid Costs: Represents AMI costs associated with the installation of smart meters and the early retirement of existing meters throughout Pepco's and DPL's service territories that are recoverable from customers. AMI has not been approved by the NJBPU for ACE in New Jersey.

Recoverable Income Taxes: Represents amounts recoverable from Power Delivery's customers for tax benefits applicable to utility operations of Pepco, DPL and ACE previously recognized in income tax expense before the companies were ordered to account for the tax benefits as deferred income taxes. As the temporary differences between the financial statement basis and tax basis of assets reverse, the deferred recoverable balances are reversed.

Deferred Energy Supply Costs: The regulatory asset represents primarily deferred costs associated with a net under-recovery of Default Electricity Supply costs incurred by Pepco, DPL and ACE that are probable of recovery in rates. The regulatory liability represents primarily deferred costs associated with a net over-recovery of Default Electricity Supply costs incurred that will be refunded by Pepco, DPL and ACE to customers.

Demand-Side Management Costs: Represents recoverable costs associated with customer energy efficiency and conservation programs in Pepco's and DPL's Maryland jurisdictions.

Incremental Storm Restoration Costs: Represents total incremental storm restoration costs incurred for repair work due to major storm events in 2012 and 2011, including Hurricane Sandy, the June 2012 derecho, Hurricane Irene and the 2011 severe winter storm (for Pepco), that are recoverable from customers in the Maryland and New Jersey jurisdictions. Pepco's and DPL's costs related to Hurricane Sandy, the June 2012 derecho, Hurricane Irene and Pepco's costs related to the 2011 severe winter storm are being amortized and recovered in rates, each over a five-year period. ACE's costs related to Hurricane Sandy, the June 2012 derecho and Hurricane Irene are being amortized and recovered in rates, each over a three-year period.

MAPP Abandonment Costs: Represents the probable recovery of abandoned costs prudently incurred in connection with the Mid-Atlantic Power Pathway (MAPP) project which was terminated by PJM Interconnection, LLC (PJM) on August 24, 2012. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. The regulatory asset will be reduced as the result of sale or alternative use of these assets. As of December 31, 2013, these assets were earning a return of 12.8%. For additional information, see "MAPP Project" discussion below.

Deferred Debt Extinguishment Costs: Represents the costs of debt extinguishment of Pepco, DPL and ACE associated with issuances of debt for which recovery through regulated utility rates is considered probable, and if approved, will be amortized to interest expense during the authorized rate recovery period.

Recoverable Workers' Compensation and Long-Term Disability Costs: Represents accrued workers' compensation and long-term disability costs for Pepco, which are recoverable from customers when actual claims are paid to employees.

Deferred Losses on Gas Derivatives: Represents losses associated with hedges of natural gas purchases that are recoverable through the Gas Cost Rate approved by the DPSC.

Other: Represents miscellaneous regulatory assets that generally are being amortized over 1 to 20 years.

Asset Removal Costs: The depreciation rates for Pepco and DPL include a component for removal costs, as approved by the relevant federal and state regulatory commissions. Accordingly, Pepco and DPL have recorded regulatory liabilities for their estimate of the difference between incurred removal costs and the amount of removal costs recovered through depreciation rates.

Deferred Income Taxes Due to Customers: Represents the portions of deferred income tax assets applicable to utility operations of Pepco and DPL that have not been reflected in current customer rates for which future payment to customers is probable. As the temporary differences between the financial statement basis and tax basis of assets reverse, deferred recoverable income taxes are amortized.

Deferred Gains on Gas Derivatives: Represents gains associated with hedges of natural gas purchases that will be refunded to customers through the Gas Cost Rate approved by the DPSC.

Excess Depreciation Reserve: The excess depreciation reserve was recorded as part of an ACE New Jersey rate case settlement. This excess reserve is the result of a change in estimated depreciable lives and a change in depreciation technique from remaining life to whole life that caused an over-recovery for depreciation expense from customers when the remaining life method had been used. The excess was amortized as a reduction in Depreciation and amortization expense over an 8.25 year period, and expired in 2013.

Other: Includes miscellaneous regulatory liabilities.

Rate Proceedings

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

Jurisdiction/Company	Requested Revenue Requirement Increase *(millions of dollars)*	Requested Return on Equity	Filing Date	Expected Timing of Decision
DC – Pepco	$ 44.8(a)	10.25%	March 8, 2013	Q1, 2014
DE – DPL (Electric)	$ 39.0(b)	10.25%	March 22, 2013	Q2, 2014
MD – Pepco	$ 43.3	10.25%	December 4, 2013	Q3, 2014

(a) Reflects Pepco's updated revenue requirement as filed on December 3, 2013.
(b) Reflects DPL's updated revenue requirement as filed on September 20, 2013.

The following table shows, for each of PHI's utility subsidiaries, the distribution base rate cases completed in 2013. Additional information concerning each of these cases is provided in the discussion below.

Jurisdiction/Company	Approved Revenue Requirement Increase *(millions of dollars)*	Approved Return on Equity	Completion Date	Rate Effective Date
NJ – ACE	$ 25.5	9.75%	June 21, 2013	July 1, 2013
MD – Pepco	$ 27.9	9.36%	July 12, 2013	July 12, 2013
MD – DPL	$ 15.0	9.81% (a)	August 30, 2013	September 15, 2013
DE – DPL (Gas)	$ 6.8	9.75% (b)	October 22, 2013	November 1, 2013

(a) Return on equity (ROE) has not been determined by any proceeding and is specified only for the purposes of calculating the AFUDC and regulatory asset carrying costs.
(b) ROE has not been determined by any proceeding and is specified only for reporting purposes and for calculating the AFUDC, construction work in process (CWIP), regulatory asset carrying costs and other accounting metrics.

Bill Stabilization Adjustment

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

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

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

Delaware

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $39 million (as adjusted by DPL on September 20, 2013), based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on June 1, 2013, subject to refund and pending final DPSC approval. On October 8, 2013, the DPSC approved DPL's request to implement an additional interim increase of $25.1 million, effective on October 22, 2013, bringing the total interim rates in effect subject to refund to $27.6 million. A final DPSC decision is expected by the second quarter of 2014.

Forward Looking Rate Plan

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

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

On October 22, 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that it would not address the FLRP until the pending electric distribution base rate case discussed above was concluded. DPL expects that the FLRP will be updated and re-filed at the conclusion of the electric distribution base rate case. A schedule for the FLRP docket has not yet been established.

Gas Distribution Base Rates

On December 7, 2012, DPL submitted an application with the DPSC to increase its natural gas distribution base rates. The filing sought approval of an annual rate increase of approximately $12.0 million (as adjusted by DPL on July 15, 2013), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing efforts to maintain safe and reliable gas service. On October 22, 2013, the DPSC approved a settlement entered into on August 27, 2013 by the DPSC Staff, the Delaware Division of the Public Advocate and DPL, which provides for an annual rate increase of $6.8 million. While the approved settlement provided that no understanding was reached concerning the appropriate ROE, it specified that for reporting purposes and for calculating the AFUDC, CWIP, regulatory asset carrying costs and other accounting metrics, the rate of 9.75% should be used. The new rates became effective on November 1, 2013.

The approved settlement also provides for a phase-in of the recovery of the deferred costs associated with DPL's deployment of the interface management unit (IMU). The IMU is part of its AMI and allows for the remote reading of gas meters. Recovery of such costs will occur through base rates over a two-year period, assuming specific milestones are met and pursuant to the following schedule: 50% of the IMU portion of DPL's AMI will be put into rates on May 1, 2014, and the remainder will be put into rates on March 1, 2015. DPL also agreed in the settlement that its next natural gas distribution base rate application may be filed with the DPSC no earlier than January 1, 2015.

Gas Cost Rates

DPL makes an annual Gas Cost Rate (GCR) filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. On August 28, 2013, DPL made its 2013 GCR filing. The rates proposed in the 2013 GCR filing would result in a GCR decrease of approximately 5.5%. On September 26, 2013, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2013, subject to refund and pending final DPSC approval.

<u>District of Columbia</u>

On March 8, 2013, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by approximately $44.8 million (as adjusted by Pepco on December 3, 2013), based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. Evidentiary hearings were held in November 2013 and a final DCPSC decision is expected in the first quarter of 2014.

<u>Maryland</u>

DPL Electric Distribution Base Rates

On March 29, 2013, DPL submitted an application with the MPSC to increase its electric distribution base rates by approximately $22.8 million, based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. DPL also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $10.2 million associated with its plan to accelerate investments in electric distribution infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force (as discussed below under "Resiliency Task Forces"). Specific projects under DPL's Grid Resiliency Charge plan included accelerating its tree-trimming cycle and upgrading five additional feeders per year for two years. In addition, DPL proposed a reliability performance-based mechanism that would allow DPL to earn up to $500,000 as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $500,000 in total if DPL did not meet at least the minimum reliability performance targets. DPL requested that any credits or charges would flow through the proposed Grid Resiliency Charge rider.

On August 30, 2013, the MPSC issued a final order approving a settlement among DPL, the MPSC staff and the Maryland Office of People's Counsel (OPC). The approved settlement provides for an annual rate increase of approximately $15 million. While the settlement does not specify an overall ROE, the parties did agree that the ROE for purposes of calculating the AFUDC and regulatory asset carrying costs would be 9.81%. The approved settlement also provides for (i) recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by amortizing the related deferred operation and maintenance expenses of approximately $6 million over a five-year period with the unamortized balance included in rate base, and (ii) a Grid Resiliency Charge for recovery of costs totaling approximately $4.2 million associated with DPL's proposed plan to accelerate investments related to certain priority feeders, provided that before implementing the surcharge, DPL provides additional information to the MPSC related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The approved settlement does not provide for approval of a portion of the Grid Resiliency Charge related to the proposed acceleration of the tree-trimming cycle, or DPL's proposed reliability performance-based mechanism. The new rates became effective on September 15, 2013.

Pepco Electric Distribution Base Rates

In December 2011, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently reduced by Pepco to $66.2 million), based on a requested ROE of 10.75%. In July 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. The order also reduced Pepco's depreciation rates, which lowered annual depreciation and amortization expenses by an estimated $27.3 million. The lower depreciation rates resulted from, among other things, the rebalancing of excess reserves for estimated future removal costs identified in a depreciation study conducted as part of the rate case filing. The identified excess reserves for estimated future removal costs, reported as Regulatory liabilities, were reclassified to Accumulated depreciation among various plant accounts. Among other things, the order additionally authorized Pepco to recover the actual cost of AMI meters installed during the 2011 test year and states that cost recovery for AMI deployment will be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. The Maryland OPC has sought rehearing on the portion of the order allowing Pepco to recover the costs of AMI meters installed during the test year; that motion remains pending.

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

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

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

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

On December 4, 2013, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $43.3 million, based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. A decision is expected in the third quarter of 2014.

New Jersey

Electric Distribution Base Rates

On December 11, 2012, ACE submitted an application with the NJBPU, updated on January 4, 2013, to increase its electric distribution base rates by approximately $70.4 million (excluding sales-and-use taxes), based on a requested ROE of 10.25%. This proposed net increase was comprised of (i) a proposed increase to ACE's distribution rates of approximately $72.1 million and (ii) a net decrease to ACE's Regulatory Asset Recovery Charge (a customer charge to recover deferred, NJBPU-approved expenses incurred as part of ACE's public service obligation) in the amount of approximately $1.7 million. The requested rate increase seeks to recover expenses associated with ACE's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service and to recover system restoration costs associated with the derecho storm in June 2012 and Hurricane Sandy in October 2012. On June 21, 2013, the NJBPU approved a settlement of the parties providing for an increase in ACE's electric distribution base rates in the amount of $25.5 million, based on an ROE of 9.75%. The base distribution revenue increase includes full recovery of the approximately $70.0 million in incremental storm restoration costs incurred as a result of recent major storm events, including the derecho storm and Hurricane Sandy, by including the related capital costs of approximately $44.2 million in rate base and amortizing the related deferred operation and maintenance expenses of approximately $25.8 million over a three-year period. Rates were effective on July 1, 2013.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012 and March 2013, ACE submitted petitions with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program for low income customers) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. In June 2012, the NJBPU approved a stipulation of settlement related to ACE's February 2012 filing, which provided for an overall annual rate increase of $55.3 million that went into effect on July 1, 2012. In May 2013, the NJBPU approved a stipulation of settlement related to ACE's March 2013 filing, which provided for an overall annual rate increase of $52.2 million (in addition to the $55.3 million approved by the NJBPU in June 2012) that went into effect on June 1, 2013. These rate increases, which primarily provide for the recovery of above-market costs associated with the NUG contracts and will have no effect on ACE's operating income, were placed into effect provisionally and were subject to a review by the NJBPU of the final underlying costs for reasonableness and prudence. On February 19, 2014, the NJBPU approved a stipulation of settlement for both proceedings, which made final the provisional rates that went into effect on July 1, 2012 and June 1, 2013, respectively.

Service Extension Contributions Refund Order

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

Generic Consolidated Tax Adjustment Proceeding

In January 2013, the NJBPU initiated a generic proceeding to examine whether a consolidated tax adjustment (CTA) should continue to be used, and if so, how it should be calculated in determining a utility's cost of service. Under the NJBPU's current policy, when a New Jersey utility is included in a consolidated group income tax return, an allocated amount of any reduction in the consolidated group's taxes as a result of losses by affiliates is used to reduce the utility's rate base, upon which the utility earns a return. Consequently, this policy has substantially reduced ACE's rate base and ACE's position is that the CTA should be eliminated. A stakeholder process has been initiated by the NJBPU to aid in this examination. No formal schedule has been set for the remainder of the proceeding or for the issuance of a decision.

Federal Energy Regulatory Commission

On October 17, 2013, the FERC issued a ruling on challenges filed by the Delaware Municipal Electric Corporation, Inc. (DEMEC) to DPL's 2011 and 2012 annual formula rate updates. In 2006, FERC approved a formula rate for DPL that is incorporated into the PJM tariff. The formula rate establishes the treatment of costs and revenues and the resulting rates for DPL. Pursuant to the protocols approved by FERC and after a period of discovery, interested parties have an opportunity to file challenges regarding the application of the formula rate. The FERC order sets various issues in this proceeding for hearing, including challenges regarding formula rate inputs, deferred income items, prepayments of estimated income taxes, rate base reductions, various administrative and general expenses and the inclusion in rate base of CWIP related to the MAPP project (which has been abandoned). Settlement discussions began in this matter on November 5, 2013 before an administrative law judge at FERC.

On December 12, 2013, DEMEC filed a formal challenge to the DPL 2013 annual formula rate update, including a request to consolidate the 2013 challenge with the two prior challenges. This challenge is pending at FERC. PHI cannot predict when a final FERC decision in this proceeding will be issued.

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as DEMEC, filed a joint complaint with FERC against Pepco, DPL and ACE, as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. PHI, Pepco, DPL and ACE believe the allegations in this complaint are without merit and are vigorously contesting it. On April 3, 2013, Pepco, DPL and ACE filed their answer to this complaint, requesting that FERC dismiss the complaint against them on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. PHI cannot predict when a final FERC decision in this proceeding will be issued.

MPSC New Generation Contract Requirement

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

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

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

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

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit. These appeals remain pending.

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

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

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three Standard Offer Capacity Agreements (SOCAs) by order of the NJBPU, each with a different generation company, as more fully described in Note (13), "Derivative Instruments and Hedging Activities." ACE and the other New Jersey EDCs entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators, were dismissed without prejudice subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. On October 11, 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause, and is therefore null and void. On October 21, 2013 a joint motion to stay the Federal district court's decision pending appeal was filed by the NJBPU and one of the SOCA generation companies. In that motion, the NJBPU notified the Federal district court that it would take no action to force implementation of the SOCAs pending the appeal or such other action—such as FERC approval of the SOCAs—that would cure the constitutional issues to the Federal district court's satisfaction. On October 25, 2013, the Federal district court issued an order denying the joint motion to stay and ruling that the SOCAs are void, invalid and unenforceable. On October 31, 2013, one of the SOCA generation companies filed a notice of appeal of the October 25, 2013 Federal district court decision with the U.S. Court of Appeals for the Third Circuit (the Federal circuit court). On November 8, 2013, the other remaining SOCA generating company filed a motion to intervene in the proceedings and a notice of appeal of the October 25, 2013 Federal district court decision. On November 21, 2013, the NJBPU filed its notice of appeal of the October 25, 2013 Federal district court decision. On November 14, 2013, the Federal circuit court granted the motion to intervene and on December 13, 2013, the Federal circuit court issued an order consolidating the appeals filed by the NJBPU and the SOCA generating companies of the October 25, 2013 Federal district court decision. The matter has been placed on an expedited schedule and appeal proceedings remain pending. The Federal circuit court is tentatively scheduled to hear the appeal on March 27, 2014.

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

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

Resiliency Task Forces

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

In August 2012, the District of Columbia mayor issued an Executive Order establishing the Mayor's Power Line Undergrounding Task Force (the DC Undergrounding Task Force). The stated purpose of the DC Undergrounding Task Force was to pool the collective resources available in the District of Columbia to produce an analysis of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead distribution facilities in the District of Columbia. These resources included legislative bodies, regulators, utility personnel, experts and other parties who could contribute in a meaningful way to the DC Undergrounding Task Force. On May 13, 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan of the DC Undergrounding Task Force to underground 60 of the District of Columbia's most outage-prone power lines, which lines would be owned and maintained by Pepco. The legislation providing for implementation of the report's recommendations contemplates that: (i) Pepco would fund approximately

$500 million of the $1 billion estimated cost to complete this project, recovering those costs through surcharges on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the undergrounding project cost would be financed by the District of Columbia's issuance of securitized bonds, which bonds would be repaid through surcharges on the electric bills of Pepco District of Columbia customers (Pepco would not earn a return on or of the cost of the assets funded with the proceeds received from the issuance of the securitized bonds, but ownership and responsibility for the operation and maintenance of such assets would be transferred to Pepco for a nominal amount); and (iii) the remaining amount would be funded through the District of Columbia Department of Transportation's existing capital projects program. This legislation was approved in the Council of the District of Columbia on February 4, 2014 and is awaiting the signature of the Mayor of the District of Columbia. Once signed by the Mayor and transmitted to Congress, the legislation will undergo a 30-day Congressional review period before becoming law, which is expected to occur in the second quarter of 2014. The final step would be DCPSC approval of the underground project plan and financing orders required by the legislation to establish the customer surcharges contemplated by the legislation, a decision on which is expected during the fourth quarter of 2014.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, PHI submitted a filing to FERC seeking recovery of approximately $88 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

On December 18, 2013, PHI submitted a settlement agreement to FERC, which provides for recovery of PHI's abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. PHI cannot predict the timing or results of a final FERC decision in this proceeding.

As of December 31, 2013, PHI had a regulatory asset related to the MAPP abandoned costs of approximately $68 million, representing the original filing amount of approximately $88 million of abandoned costs referred to above less: (i) approximately $2 million of disallowed costs written off in 2013; (ii) $4 million of materials transferred to inventories for use on other projects; and (iii) $14 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration.

(8) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	Original Cost	Accumulated Depreciation	Net Book Value
	(millions of dollars)		
At December 31, 2013			
Generation	$ 105	$ 99	$ 6
Distribution	8,896	2,961	5,935
Transmission	2,991	908	2,083
Gas	481	142	339
Construction work in progress	677	—	677
Non-operating and other property	1,417	753	664
Total	$14,567	$ 4,863	$ 9,704
At December 31, 2012			
Generation	$ 107	$ 97	$ 10
Distribution	8,320	2,954	5,366
Transmission	2,783	866	1,917
Gas	458	137	321
Construction work in progress	692	—	692
Non-operating and other property	1,265	725	540
Total	$13,625	$ 4,779	$ 8,846

The non-operating and other property amounts include balances for general plant, intangible plant, distribution plant and transmission plant held for future use as well as other property held by non-utility subsidiaries. Utility plant is generally subject to a first mortgage lien.

Pepco Holdings' utility subsidiaries use separate depreciation rates for each electric plant account. The rates vary from jurisdiction to jurisdiction.

Jointly Owned Plant

PHI's consolidated balance sheets include its proportionate share of assets and liabilities related to jointly owned plant. At December 31, 2013 and 2012, PHI's subsidiaries had a net book value ownership interest of $12 million and $13 million, respectively, in transmission and other facilities in which various parties also have ownership interests. PHI's share of the operating and maintenance expenses of the jointly-owned plant is included in the corresponding expenses in the consolidated statements of (loss) income. PHI is responsible for providing its share of the financing for the above jointly-owned facilities.

Capital Leases

Pepco leases its consolidated control center, which is an integrated energy management center used by Pepco to centrally control the operation of its transmission and distribution systems. This lease is accounted for as a capital lease and was initially recorded at the present value of future lease payments, which totaled $152 million. The lease requires semi-annual payments of approximately $8 million over a 25-year period that began in December 1994, and provides for transfer of ownership of the system to Pepco for $1 at the end of the lease term. Under FASB guidance on regulated operations, the amortization of leased assets is modified so that the total interest expense charged on the obligation and amortization expense of the leased asset is equal to the rental expense allowed for rate-making purposes. The amortization expense is included within Depreciation and amortization in the consolidated statements of (loss) income. This lease is treated as an operating lease for rate-making purposes.

Capital lease assets recorded within Property, Plant and Equipment at December 31, 2013 and 2012, in millions of dollars, are comprised of the following:

	Original Cost	Accumulated Amortization	Net Book Value
At December 31, 2013			
Transmission	$ 76	$ 41	$ 35
Distribution	76	42	34
General	3	3	—
Total	$ 155	$ 86	$ 69
At December 31, 2012			
Transmission	$ 76	$ 37	$ 39
Distribution	76	37	39
General	3	3	—
Total	$ 155	$ 77	$ 78

The approximate annual commitments under all capital leases are $15 million for each year 2014 through 2018, and $16 million thereafter.

Deactivation of Pepco Energy Services' Generating Facilities

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. The facilities were located in Washington, D.C. and had a generating capacity of approximately 790 megawatts. During the years ended December 31, 2012 and 2011, PHI has recorded decommissioning costs of $3 million and $2 million, respectively, related to these generating facilities.

Pepco Energy Services placed the facilities into an idle condition termed a "cold closure." A cold closure requires that the utility service be disconnected so that the facilities are no longer operable and require only essential maintenance until they are completely decommissioned. During the third quarter of 2013, Pepco Energy Services determined that it would be more cost effective to pursue the demolition of the Benning Road generation facility and realization of the scrap metal salvage value of the facility instead of maintaining cold closure status. The demolition of the facility commenced in the fourth quarter of 2013 and is expected to be completed by the end of 2014. Pepco Energy Services will recognize the salvage proceeds associated with the scrap metals at the facility as realized.

Long-Lived Asset Impairment

For the years ended December 31, 2013 and 2012, PHI recorded impairment losses of $4 million ($3 million after-tax) and $12 million ($7 million after-tax), respectively, at Pepco Energy Services associated primarily with its investments in landfill gas-fired electric generation facilities. In 2012, the impairment loss also included the reduction in the estimated net realizable value of the combustion turbines at Buzzard Point. PHI performed a long-lived asset impairment test on the landfill generation facilities of Pepco Energy Services as a result of a sustained decline in energy prices and recent production levels. The asset value of the facilities was written down to their estimated fair value because the future expected cash flows of the facilities were not sufficient to provide recovery of the facilities' carrying value. PHI estimated the fair value of the facilities by calculating the present value of expected future cash flows using an appropriate discount rate. Both the expected future cash flows and the discount rate used primarily unobservable inputs.

Asset Retirement Obligations

PHI recognizes liabilities related to the retirement of long-lived assets in accordance with ASC 410. In connection with Pepco Energy Services' decommissioning of the Buzzard Point and Benning Road generation facilities, PHI has recorded an asset retirement obligation of $2 million and $9 million as of December 31, 2013 and 2012, respectively on its consolidated balance sheets.

During 2013, Pepco Energy Services determined that it would be more cost effective to pursue the demolition of the Benning Road generation facility instead of maintaining cold closure status. As a result of this change in intent, Pepco Energy Services reduced its asset retirement obligation related to the facility by $2 million.

The sale of the Conectiv Energy wholesale power generation business to Calpine Corporation (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 for 30 years. PHI has recorded an asset retirement obligation of $6 million on its consolidated balance sheet related to the Edge Moor landfill.

(9) PENSION AND OTHER POSTRETIREMENT BENEFITS

The following table shows changes in the benefit obligation and plan assets for the years ended December 31, 2013 and 2012:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Change in Benefit Obligation				
Benefit obligation as of January 1	$2,494	$2,124	$ 775	$ 750
Service cost	53	35	8	7
Interest cost	100	107	29	35
Amendments	3	—	(124)	—
Actuarial (gain) loss	(277)	341	(71)	24
Benefits paid (a)	(135)	(113)	(43)	(41)
Benefit obligation as of December 31	$2,238	$2,494	$ 574	$ 775
Change in Plan Assets				
Fair value of plan assets as of January 1	$2,039	$1,694	$ 321	$ 281
Actual return on plan assets	86	252	56	38
Company and participant contributions	126	206	34	43
Benefits paid (a)	(135)	(113)	(43)	(41)
Fair value of plan assets as of December 31	$2,116	$2,039	$ 368	$ 321
Funded Status at end of year (plan assets less plan obligations)	$ (122)	$ (455)	$ (206)	$ (454)

(a) Other Postretirement Benefits paid is net of Medicare Part D subsidy receipts of zero and $4 million in 2013 and 2012, respectively.

At December 31, 2013 and 2012, the PHI Retirement Plan's accumulated benefit obligation was approximately $2.1 billion and $2.3 billion, respectively. The accumulated benefit obligation differs from the pension benefit obligation presented in the table above in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the amounts recorded in PHI's consolidated balance sheets as of December 31, 2013 and 2012:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Regulatory asset	$ 664	$ 934	$ 3	$ 237
Current liabilities	(6)	(6)	—	—
Pension benefit obligation	(116)	(449)	—	—
Other postretirement benefit obligations	—	—	(206)	(454)
Deferred income tax liabilities, net	(217)	(216)	82	88
Accumulated other comprehensive loss, net of tax	25	32	—	—
Net amount recorded	$ 350	$ 295	$ (121)	$ (129)

Amounts included in AOCL (pre-tax) and Regulatory assets at December 31, 2013 and 2012, consist of:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Unrecognized net actuarial loss	$694	$979	$ 117	$ 238
Unamortized prior service cost (credit)	10	9	(114)	(1)
Total	$704	$988	$ 3	$ 237
Accumulated other comprehensive loss ($25 million and $32 million, net of tax, at December 31, 2013 and 2012, respectively)	$ 40	$ 54	$ —	$ —
Regulatory assets	664	934	3	237
Total	$704	$988	$ 3	$ 237

Under FASB guidance on regulated operations, a portion of actuarial gains and losses and prior service costs (credits) are included in Regulatory assets (liabilities) in the consolidated balance sheets to reflect expected regulatory recovery of such amounts, which otherwise would be recorded to AOCL. The table below provides the changes in plan assets and benefit obligations recognized in AOCL and Regulatory assets for the years ended December 31, 2013, 2012 and 2011.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
	(millions of dollars)					
Amounts amortized during the year:						
Amortization of prior service (cost) credit	$ (2)	$ (1)	$ —	$ 11	$ 4	$ 5
Amortization of net actuarial (loss)	(67)	(64)	(47)	(12)	(14)	(14)
Amounts arising during the year:						
Current year prior service cost (credit)	3	—	19	(124)	—	6
Current year actuarial (gain) loss	(218)	220	177	(109)	4	53
Total recognized in AOCL and Regulatory assets for the year ended December 31	$(284)	$155	$ 149	$(234)	$ (6)	$ 50

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from AOCL or Regulatory assets into net periodic benefit cost over the next reporting year are $44 million and $2 million, respectively. The estimated net actuarial loss and prior service credit for the OPEB plan that will be amortized from AOCL or Regulatory assets into net periodic benefit cost over the next reporting year are $6 million and $13 million, respectively.

The table below provides the components of net periodic benefit costs recognized for the years ended December 31, 2013, 2012 and 2011:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
	(millions of dollars)					
Service cost	$ 53	$ 35	$ 35	$ 8	$ 7	$ 5
Interest cost	100	107	107	29	35	37
Expected return on plan assets	(145)	(132)	(128)	(20)	(18)	(19)
Amortization of prior service cost (credit)	2	1	—	(11)	(4)	(5)
Amortization of net actuarial loss	67	64	47	12	14	14
Termination benefits	—	—	—	—	1	1
Net periodic benefit cost	$ 77	$ 75	$ 61	$ 18	$ 35	$ 33

The table below provides the split of the combined pension and other postretirement net periodic benefit costs among subsidiaries for the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2011
	(millions of dollars)		
Pepco	$34	$ 39	$43
DPL	18	23	23
ACE	17	24	21
Other subsidiaries	26	24	7
Total	$95	$110	$94

The following weighted average assumptions were used to determine the benefit obligations at December 31:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Discount rate	5.05%	4.15%	5.00%	4.10%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%
Health care cost trend rate assumed for current year – pre 65	—	—	7.00%	7.50%
Health care cost trend rate assumed for current year – post 65	—	—	5.60%	7.50%
Rate to which the cost trend rate is assumed to decline for all eligible retirees (the ultimate trend rate)	—	—	5.00%	5.00%
Year that the cost trend rate reaches the ultimate trend rate	—	—	2020	2018

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects, in millions of dollars:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Increase (decrease) in total service and interest cost	$ 1	$ (1)
Increase (decrease) in postretirement benefit obligation	$ 17	$ (19)

The following weighted average assumptions were used to determine the net periodic benefit cost for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.15%	5.00%	5.65%	4.10%/4.95% (a)	4.90%	5.60%
Expected long-term return on plan assets	7.00%	7.25%	7.75%	7.00%	7.25%	7.75%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Health care cost trend rate	—	—	—	7.50%	8.00%	8.00%

(a) The discount rate was updated for remeasurement to 4.95% on July 1, 2013.

PHI utilizes an analytical tool developed by its actuaries to select the discount rate. The analytical tool utilizes a high-quality bond portfolio with cash flows that match the benefit payments expected to be made under the plans.

PHI uses a building block approach to estimate the expected rate of return on plan assets. Under this approach, the percentage of plan assets in each asset class according to PHI's target asset allocation, at the beginning of the year, is applied to the expected asset return for the related asset class. PHI incorporates long-term assumptions for real returns, inflation expectations, volatility and correlations among asset classes to determine expected returns for a given asset allocation. The pension and postretirement benefit plan assets consist of equity, fixed income, real estate and private equity investments. PHI periodically reviews its asset mix and rebalances assets to the target allocation.

The average remaining service periods for participating employees of the benefit plans was approximately 11 years for both 2013 and 2012. PHI utilizes plan census data to estimate these average remaining service periods. PHI uses the IRS prescribed mortality tables to estimate the average life expectancy. The IRS prescribed tables for 2013 and 2012 were used to determine net periodic pension and OPEB cost for the same respective years. The tables for 2014 and 2013 were used for determining the benefit obligations as of December 31, 2013 and 2012, respectively.

Benefit Plan Modifications

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and the retiree life insurance benefits, and were effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $193 million reduction of the accumulated postretirement benefit obligation, which included recording a prior service credit of $124 million, which will be amortized over approximately ten years, and a $69 million reduction from a change in the discount rate from 4.10% as of December 31, 2012 to 4.95% as of July 1, 2013. The remeasurement resulted in a $17 million reduction in net periodic benefit cost for other postretirement benefits during 2013, when compared to 2012. Approximately 37% of net periodic other postretirement benefit costs were capitalized in 2013.

Plan Assets

Investment Policies and Strategies

In developing its allocation policy for the assets in the PHI Retirement Plan and the other postretirement benefit plan, PHI examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, PHI evaluated the risk and return tradeoffs of alternative asset classes and asset mixes given long-term historical relationships as well as prospective capital market returns. PHI also conducted an asset-liability study to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. PHI developed its asset mix guidelines by incorporating the results of these analyses with an assessment of its risk posture, and taking into account industry practices. PHI periodically evaluates its investment strategy to ensure that plan assets are sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, PHI may make changes to its targeted asset allocations and investment strategy.

PHI's pension investment strategy is designed to meet the following investment objectives:

- Generate investment returns that, in combination with funding contributions from PHI, provide adequate funding to meet all current and future benefit obligations of the plan.
- Provide investment results that meet or exceed the assumed long-term rate of return, while maintaining the funded status of the plan at acceptable levels.
- Improve funded status over time.
- Decrease contribution and expense volatility as funded status improves.

To achieve these investment objectives, PHI's investment strategy divides the pension program into two primary portfolios:

Return-Seeking Assets—These assets are intended to provide investment returns in excess of pension liability growth and reduce existing deficits in the funded status of the plan. The category includes a diversified mix of U.S. large and small cap equities, non-U.S. developed and emerging market equities, real estate, and private equity.

Liability-Hedging Assets—These assets are intended to reflect the sensitivity of the plan's liabilities to changes in discount rates. This category includes a diversified mix of long duration, primarily investment grade credit and U.S. treasury securities.

PHI follows an asset-liability management strategy for PHI Retirement Plan assets in order to reduce the effects of future volatility of the fair value of its pension plan assets relative to its pension plan liabilities. For example, in 2013, this strategy uses a 66% target allocation to fixed income investments, primarily in high quality, longer-maturity fixed income securities. The PHI Retirement Plan asset allocations at December 31, 2013 and 2012, by asset category, were as follows:

Asset Category	Plan Assets at December 31,		Target Plan Asset Allocation	
	2013	2012	2013	2012
Equity	31%	30%	28%	32%
Fixed Income	62%	62%	66%	62%
Other (real estate, private equity)	7%	8%	6%	6%
Total	100%	100%	100%	100%

PHI's other postretirement benefit plan asset allocations at December 31, 2013 and 2012, by asset category, were as follows:

Asset Category	Plan Assets at December 31,		Target Plan Asset Allocation	
	2013	2012	2013	2012
Equity	63%	62%	60%	60%
Fixed Income	31%	36%	35%	35%
Cash	6%	2%	5%	5%
Total	100%	100%	100%	100%

PHI will rebalance the plan asset portfolios when the actual allocations fall outside the ranges outlined in the investment policy or as funded status improves over a reasonable period of time.

Risk Management

Pension and other postretirement benefit plan assets may be invested in separately managed accounts in which there is ownership of individual securities, shares of commingled funds or mutual funds, or limited partnerships. Commingled funds and mutual funds are subject to detailed policy guidelines set forth in the fund's prospectus or fund declaration, and limited partnerships are subject to the terms of the partnership agreement.

Separate account investment managers are responsible for achieving a level of diversification in their portfolio that is consistent with their investment approach and their role in PHI's overall investment structure. Separate account investment managers must follow risk management guidelines established by PHI unless authorized in writing by PHI.

Derivative instruments are permissible in an investment portfolio to the extent they comply with policy guidelines and are consistent with risk and return objectives. Under no circumstances may such instruments be used speculatively or to leverage the portfolio. Separately managed accounts are prohibited from holding securities issued by the following firms:

- PHI and its subsidiaries,
- PHI's pension plan trustee, its parent or its affiliates,
- PHI's pension plan consultant, its parent or its affiliates, and
- PHI's pension plan investment manager, its parent or its affiliates

Fair Value of Plan Assets

As defined in the FASB guidance on fair value measurement and disclosures (ASC 820), 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. The FASB's fair value framework includes a hierarchy that prioritizes the inputs to valuation techniques 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). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument. Investments are classified within the fair value hierarchy as follows:

Level 1: Investments are valued using quoted prices in active markets for identical instruments.

Level 2: Investments are valued using other significant observable inputs (e.g., quoted prices for similar investments, interest rates, credit risks, etc).

Level 3: Investments are valued using significant unobservable inputs, including internal assumptions.

There were no significant transfers between level 1 and level 2 during the years ended December 31, 2013 and 2012.

The following tables present the fair values of PHI's pension and other postretirement benefit plan assets by asset category within the fair value hierarchy levels, as of December 31, 2013 and 2012:

	Fair Value Measurements at December 31, 2013 *(millions of dollars)*			
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Pension Plan Assets:				
Equity				
Domestic (a)	$ 432	$ 185	$ 213	$ 34
International (b)	217	215	1	1
Fixed Income (c)	1,309	—	1,298	11
Other				
Private Equity	53	—	—	53
Real Estate	61	—	—	61
Cash Equivalents (d)	44	44	—	—
Pension Plan Assets Subtotal	2,116	444	1,512	160
Other Postretirement Plan Assets:				
Equity (e)	233	204	29	—
Fixed Income (f)	113	113	—	—
Cash Equivalents	22	22	—	—
Postretirement Plan Assets Subtotal	368	339	29	—
Total Pension and Other Postretirement Assets	$2,484	$ 783	$ 1,541	$ 160

(a) Predominantly includes domestic common stock and commingled funds.
(b) Predominantly includes foreign common and preferred stock and warrants.
(c) Predominantly includes corporate bonds, government bonds, municipal/provincial bonds, collateralized mortgage obligations and commingled funds.
(d) Predominantly includes cash investment in short-term investment funds.
(e) Includes domestic and international commingled funds.
(f) Includes fixed income commingled funds.

Asset Category	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2012 *(millions of dollars)*			
Pension Plan Assets:				
Equity				
Domestic (a)	$ 367	$ 169	$ 170	$ 28
International (b)	254	250	1	3
Fixed Income (c)	1,256	—	1,243	13
Other				
Private Equity	56	—	—	56
Real Estate	74	—	—	74
Cash Equivalents (d)	32	32	—	—
Pension Plan Assets Subtotal	2,039	451	1,414	174
Other Postretirement Plan Assets:				
Equity (e)	199	171	28	—
Fixed Income (f)	115	115	—	—
Cash Equivalents	7	7	—	—
Postretirement Plan Assets Subtotal	321	293	28	—
Total Pension and Other Postretirement Plan Assets	$2,360	$ 744	$ 1,442	$ 174

(a) Predominantly includes domestic common stock and commingled funds.
(b) Predominantly includes foreign common and preferred stock and warrants.
(c) Predominantly includes corporate bonds, government bonds, municipal/provincial bonds, collateralized mortgage obligations and commingled funds.
(d) Predominantly includes cash investment in short-term investment funds.
(e) Includes domestic and international commingled funds.
(f) Includes fixed income commingled funds.

There were no significant concentrations of risk in pension and OPEB plan assets at December 31, 2013 and 2012.

Valuation Techniques Used to Determine Fair Value

Equity

Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. PHI can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, therefore they would be classified as level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid/ask prices, and these measurements would be classified as level 2 investments. Investments that are not publicly traded and valued using unobservable inputs would be classified as level 3 investments.

Commingled funds with publicly quoted prices and active trading are classified as level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the net asset value (NAV) per fund share, derived from the underlying securities' quoted prices in active markets, and are classified as level 2 investments. Investments in commingled funds with redemption restrictions that use NAV are classified as level 3 investments.

Fixed Income

Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Like the equity securities, fair values generated from active trading on exchanges are classified as level 1 investments. Prices generated from less active trading with wider bid/ask prices are classified as level 2 investments. If prices are based on uncorroborated and unobservable inputs, then the investments are classified as level 3 investments.

Commingled funds with publicly quoted prices and active trading are classified as level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and are classified as level 2 investments. Investments in commingled funds with redemption restrictions that use NAV are classified as level 3 investments.

Other – Private Equity and Real Estate

Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts and partnerships, as well as equity and debt issued by public or private companies. As a practical expedient, PHI's interest in the fund or partnership is estimated at NAV. PHI's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. PHI views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. The funds utilize valuation techniques consistent with the market, income and cost approaches to measure the fair value of certain real estate investments. As a result, PHI classifies these investments as level 3 investments.

The investments in private equity and real estate funds require capital commitments, which may be called over a specific number of years. Unfunded capital commitments as of December 31, 2013 and 2012 totaled $12 million and $15 million, respectively.

Reconciliations of the beginning and ending balances of PHI's fair value measurements using significant unobservable inputs (level 3) for investments in the pension plan for the years ended December 31, 2013 and 2012 are shown below:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) *(millions of dollars)*				
	Equity	**Fixed Income**	**Private Equity**	**Real Estate**	**Total Level 3**
Balance as of January 1, 2013	$ 31	$ 13	$ 56	$ 74	$ 174
Transfer in (out) of Level 3	—	(3)	—	—	(3)
Purchases	—	—	2	2	4
Sales	(5)	(1)	—	(13)	(19)
Settlements	—	2	(4)	(10)	(12)
Unrealized gain/(loss)	7	—	(7)	7	7
Realized gain	2	—	6	1	9
Balance as of December 31, 2013	$ 35	$ 11	$ 53	$ 61	$ 160

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
	(millions of dollars)				
	Equity	Fixed Income	Private Equity	Real Estate	Total Level 3
Balance as of January 1, 2012	$ 27	$ 9	$ 64	$ 65	$ 165
Transfer in (out) of Level 3	—	2	—	—	2
Purchases	4	2	4	5	15
Sales	(4)	(1)	—	—	(5)
Settlements	(1)	1	(8)	(5)	(13)
Unrealized gain/(loss)	4	—	(11)	8	1
Realized gain	1	—	7	1	9
Balance as of December 31, 2012	$ 31	$ 13	$ 56	$ 74	$ 174

Cash Flows

Contributions—PHI Retirement Plan

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. During 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $80 million, $10 million and $30 million, respectively, which brought the PHI Retirement Plan assets to the funding target level for 2013 under the Pension Protection Act. During 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 plan assets to the funding target level for 2012 under the Pension Protection Act.

Contributions—Other Postretirement Benefit Plan

In 2013 and 2012, Pepco contributed $6 million and $5 million, respectively, DPL contributed $3 million and $7 million, respectively, and ACE contributed $6 million and $7 million, respectively, to the other postretirement benefit plan. In 2013 and 2012, contributions of $7 million and $13 million, respectively, were made by other PHI subsidiaries.

Expected Benefit Payments

Estimated future benefit payments to participants in PHI's pension and other postretirement benefit plans, which reflect expected future service as appropriate, are as follows:

Years	Pension Benefits	Other Postretirement Benefits
	(millions of dollars)	
2014	$ 159	$ 38
2015	136	39
2016	139	39
2017	142	40
2018	147	40
2019 through 2023	$ 795	$ 201

Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act)

On December 8, 2003, the Medicare Act became effective. The Medicare Act introduced Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Pepco Holdings sponsors postretirement health care plans that provide prescription drug benefits that PHI plan actuaries have determined are actuarially equivalent to Medicare Part D. In 2012, Pepco Holdings received $4 million in federal Medicare prescription drug subsidies. PHI did not receive the Part D subsidy in 2013 and will not receive it in the future due to the implementation of an Employer Group Waiver Plan which is not eligible for Part D reimbursements.

Pepco Holdings Retirement Savings Plan

Pepco Holdings has a defined contribution retirement savings plan. Participation in the plan is voluntary. All participants are 100% vested and have a nonforfeitable interest in their own contributions and in the Pepco Holdings' company matching contributions, including any earnings or losses thereon. Pepco Holdings' matching contributions were $12 million, $12 million and $11 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(10) DEBT

Long-Term Debt

The components of long-term debt are shown in the table below:

Interest Rate	Maturity	At December 31, 2013	At December 31, 2012
		(millions of dollars)	
First Mortgage Bonds			
Pepco:			
4.95% (a)(b)	2013	$ —	$ 200
4.65% (a)(b)	2014	175	175
3.05%	2022	200	200
6.20% (c)(d)	2022	110	110
5.75% (a)(b)	2034	100	100
5.40% (a)(b)	2035	175	175
6.50% (a)(c)	2037	500	500
7.90%	2038	250	250
4.15%	2043	250	—
4.95%	2043	150	—
ACE:			
6.63%	2013	—	69
7.63% (e)	2014	7	7
7.68% (e)	2015 - 2016	17	17
7.75%	2018	250	250
6.80% (b)(f)	2021	39	39
4.35%	2021	200	200
4.875% (c)(f)	2029	23	23
5.80% (b)(g)	2034	120	120
5.80% (b)(g)	2036	105	105
DPL:			
6.40%	2013	—	250
5.22% (h)	2016	100	100
3.50%	2023	300	—
4.00%	2042	250	250
Total First Mortgage Bonds		3,321	3,140
Unsecured Tax-Exempt Bonds			
DPL:			
5.40%	2031	78	78
Total Unsecured Tax-Exempt Bonds		$ 78	$ 78

NOTE: Schedule is continued on next page.

Interest Rate	Maturity	At December 31, 2013	2012
		(millions of dollars)	
Medium-Term Notes (unsecured)			
DPL:			
7.56% - 7.58%	2017	$ 14	$ 14
6.81%	2018	4	4
7.61%	2019	12	12
7.72%	2027	10	10
Total Medium-Term Notes (unsecured)		40	40
ACE Variable Rate Term Loan	2014	100	—
Recourse Debt			
PCI:			
6.59% - 6.69%	2014	11	11
Notes (secured)			
Pepco Energy Services:			
5.90% - 7.46%	2017-2024	14	15
Notes (unsecured)			
PHI:			
2.70%	2015	250	250
5.90%	2016	190	190
6.125%	2017	81	81
7.45%	2032	185	185
DPL:			
5.00%	2014	100	100
5.00%	2015	100	100
Total Notes (unsecured)		906	906
Total Long-Term Debt		4,470	4,190
Net unamortized discount		(14)	(13)
Current portion of long-term debt		(403)	(529)
Total Net Long-Term Debt		$ 4,053	$ 3,648

(a) Represents a series of Collateral First Mortgage Bonds securing a series of senior notes issued by Pepco.
(b) Represents a series of Collateral First Mortgage Bonds (as defined herein) which must be cancelled and released as security for the issuer's obligations under the corresponding series of issuer notes (as defined herein) or tax-exempt bonds, at such time as the issuer does not have any first mortgage bonds outstanding (other than its Collateral First Mortgage Bonds).
(c) Represents a series of Collateral First Mortgage Bonds which must be cancelled and released as security for the issuer's obligations under the corresponding series of issuer notes or tax-exempt bonds, at such time as the issuer does not have any first mortgage bonds outstanding (other than its Collateral First Mortgage Bonds), except that the issuer may not permit such release of collateral unless the issuer substitutes comparable obligations for such collateral.
(d) Represents a series of Collateral First Mortgage Bonds securing a series of senior notes issued by Pepco, which in turn secures a series of tax-exempt bonds issued for the benefit of Pepco.
(e) Represents a series of Collateral First Mortgage Bonds securing a series of medium term notes issued by ACE.
(f) Represents a series of Collateral First Mortgage Bonds securing a series of tax-exempt bonds issued for the benefit of ACE.
(g) Represents a series of Collateral First Mortgage Bonds securing a series of senior notes issued by ACE.
(h) Represents a series of Collateral First Mortgage Bonds securing a series of debt securities issued by DPL.

The outstanding first mortgage bonds issued by each of Pepco, DPL and ACE are issued under a mortgage and deed of trust and are secured by a first lien on substantially all of the issuing company's property, plant and equipment, except for certain property excluded from the lien of the respective mortgage.

PHI's long-term debt is subject to certain covenants. As of December 31, 2013, PHI and its subsidiaries were in compliance with all such covenants.

The table above does not separately identify $1,060 million, $100 million and $249 million in aggregate principal amount of senior notes, medium term notes and other debt securities (issuer notes) issued by each of Pepco, DPL and ACE, respectively, and $110 million and $62 million in aggregate principal amount of tax-exempt bonds issued for the benefit of Pepco and ACE, respectively. These issuer notes are secured by a like amount of first mortgage bonds (Collateral First Mortgage Bonds) of each respective issuer. In addition, these tax-exempt bonds are secured by a like amount of Collateral First Mortgage Bonds issued by the utility subsidiary for whose benefit the tax-exempt bonds were issued. The principal terms of each such series of issuer notes, or the issuer's obligations in respect of each such series of tax-exempt bonds, are identical to the same terms of the corresponding series of Collateral First Mortgage Bonds. Payments of principal and interest made on a series of such issuer notes, or the satisfaction of the issuer's obligations in respect of a series of such tax-exempt bonds, satisfy the corresponding obligations on the related series of Collateral First Mortgage Bonds. For these reasons, each such series of Collateral First Mortgage Bonds and the corresponding issuer notes and/or tax-exempt bonds together effectively represent a single financial obligation and are not identified in the table above separately.

Bond Issuances

During 2013, Pepco issued $250 million of 4.15% first mortgage bonds due March 15, 2043 and $150 million of 4.95% first mortgage bonds due November 15, 2043. Net proceeds from the issuance of the 4.15% bonds were used to repay Pepco's outstanding commercial paper and for general corporate purposes. The net proceeds from the 4.95% bonds were used to repay outstanding commercial paper, including commercial paper issued to repay in full at maturity $200 million of Pepco's 4.95% senior notes due November 15, 2013, plus accrued but unpaid interest thereon. The senior notes were secured by a like principal amount of Pepco's first mortgage bonds, which under Pepco's Mortgage and Deed of Trust were deemed to be satisfied with the repayment of the senior notes.

During 2013, DPL issued $300 million of 3.50% first mortgage bonds due November 15, 2023. The net proceeds from the issuance of the long-term debt were used to repay at maturity $250 million of DPL's 6.40% first mortgage bonds, plus accrued but unpaid interest thereon, to repay outstanding commercial paper and for general corporate purposes.

Bond Redemptions

During 2013, Pepco repaid at maturity $200 million of its 4.95% senior notes, which were secured by a like principal amount of its first mortgage bonds as previously discussed.

During 2013, DPL repaid at maturity $250 million of its 6.40% first mortgage bonds.

During 2013, ACE repaid at maturity $69 million of its 6.63% non-callable first mortgage bonds. ACE also funded the redemption, prior to maturity, of $4 million of outstanding weekly variable rate pollution control revenue refunding bonds due 2017, issued by the Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit.

ACE Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the London Interbank Offered Rate (LIBOR) with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE's Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of December 31, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.92%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of December 31, 2013.

Transition Bonds Issued by ACE Funding

The components of transition bonds are shown in the table below:

Interest Rate	Maturity	At December 31, 2013	At December 31, 2012
		(millions of dollars)	
4.46%	2016	$ 8	$ 19
4.91%	2017	46	75
5.05%	2020	54	54
5.55%	2023	147	147
Total Transition Bonds		255	295
Net unamortized discount		—	—
Current portion of long-term debt		(41)	(39)
Total Net Long-Term Transition Bonds		$ 214	$ 256

For a description of the Transition Bonds, see Note (16), "Variable Interest Entities – ACE Funding."

Maturities of PHI's long-term debt and Transition Bonds outstanding at December 31, 2013 are $444 million in 2014, $409 million in 2015, $338 million in 2016, $133 million in 2017, $286 million in 2018 and $3,115 million thereafter.

Long-Term Project Funding

As of December 31, 2013 and 2012, Pepco Energy Services had total outstanding long-term project funding (including current maturities) of $12 million and $13 million, respectively, related to energy savings contracts performed by Pepco Energy Services. The aggregate amounts of maturities for the project funding debt outstanding at December 31, 2013, are $2 million for 2014, $2 million for 2015, $1 million for each year 2016 and 2017, $2 million for 2018, and $4 million thereafter.

Short-Term Debt

PHI and its regulated utility subsidiaries have traditionally used a number of sources to fulfill short-term funding needs, such as commercial paper, short-term notes, and bank lines of credit. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements. The components of PHI's short-term debt at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Commercial paper	$ 442	$ 637
Variable rate demand bonds	123	128
Term loan agreement	—	200
Total	$ 565	$ 965

Commercial Paper

PHI, Pepco, DPL and ACE maintain ongoing commercial paper programs to address short-term liquidity needs. As of December 31, 2013, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $350 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, Pepco, DPL and ACE had $24 million, $151 million, $147 million and $120 million, respectively, of commercial paper outstanding at December 31, 2013. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during 2013 was 0.70%, 0.34%, 0.29% and 0.31%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during 2013 was five, five, three and four days, respectively.

PHI, Pepco, DPL and ACE had $264 million, $231 million, $32 million and $110 million, respectively, of commercial paper outstanding at December 31, 2012. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during 2012 was 0.87%, 0.43%, 0.43% and 0.41%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE in 2012 was ten, five, four and three days, respectively.

Variable Rate Demand Bonds

PHI's utility subsidiaries DPL and ACE, each have outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. PHI expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the issuer and, as applicable, the credit support, and because the remarketing resets the interest rate to the then-current market rate. The bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, PHI views VRDBs as a source of long-term financing. As of December 31, 2013, $105 million of VRDBs issued on behalf of DPL (of which $72 million were secured by Collateral First Mortgage Bonds issued by DPL) and $18 million of VRDBs issued on behalf of ACE were outstanding.

The VRDBs outstanding at December 31, 2013 mature as follows: 2014 to 2017 ($44 million), 2024 ($33 million) and 2028 to 2029 ($46 million). The weighted average interest rate for VRDBs was 0.24% during 2013 and 0.34% during 2012.

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On August 1, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained the same.

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

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month 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 December 31, 2013.

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

As of December 31, 2013 and 2012, the amount of cash plus unused borrowing capacity under the credit facility available to meet the future liquidity needs of PHI and its utility subsidiaries on a consolidated basis totaled $1,063 million and $861 million, respectively. PHI's utility subsidiaries had combined cash and unused borrowing capacity under the credit facility of $332 million and $477 million at December 31, 2013 and 2012, respectively.

Other Financing Activities

PHI Term Loan Agreement

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

Long-Term Project Funding

On October 24, 2013, Pepco Energy Services entered into an agreement with a lender to receive up to $8 million in construction financing at an interest rate of 4.68% for an energy savings project that is expected to be completed in 2014. The agreement includes a transfer of receivables from Pepco Energy Services to the lender after construction is completed, under which the customer would make contractual payments over a 23-year period to repay the financing. If there are shortfalls in Pepco Energy Services' energy savings guarantee or other performance obligations to the customer that reduce customer payments below the contractual payment amounts, then Pepco Energy Services would compensate the lender for the unpaid amounts. PHI has guaranteed the performance obligations of Pepco Energy Services under the financing agreement.

(11) INCOME TAXES

PHI and the majority of its subsidiaries file a consolidated federal income tax return. Federal income taxes are allocated among PHI and the subsidiaries included in its consolidated group pursuant to a written tax sharing agreement that was approved by the SEC in 2002 in connection with the establishment of PHI as a public utility holding company. Under this tax sharing agreement, PHI's consolidated federal income tax liability is allocated based upon PHI's and its subsidiaries' separate taxable income or loss.

The provision for consolidated income taxes, reconciliation of consolidated income tax expense, and components of consolidated deferred tax liabilities (assets) are shown below.

Provision for Consolidated Income Taxes – Continuing Operations

	For the Year Ended December 31,		
	2013	2012	2011
		(millions of dollars)	
Current Tax (Benefit) Expense			
Federal	$ (128)	$ (166)	$ (72)
State and local	(9)	(40)	12
Total Current Tax (Benefit) Expense	(137)	(206)	(60)
Deferred Tax Expense (Benefit)			
Federal	393	254	163
State and local	65	58	15
Investment tax credit amortization	(2)	(3)	(4)
Total Deferred Tax Expense	456	309	174
Total Consolidated Income Tax Expense Related to Continuing Operations	$ 319	$ 103	$ 114

Reconciliation of Consolidated Income Tax Expense – Continuing Operations

	For the Year Ended December 31,					
	2013		2012		2011	
			(millions of dollars)			
Income tax at Federal statutory rate	$150	35.0%	$112	35.0%	$118	35.0%
Increases (decreases) resulting from:						
State income taxes, net of Federal effect	27	6.3%	19	6.0%	23	6.7%
Asset removal costs	(14)	(3.3)%	(11)	(3.4)%	(7)	(2.1)%
Change in estimates and interest related to uncertain and effectively settled tax positions	56	13.1%	(8)	(2.6)%	(5)	(1.6)%
Establishment of valuation allowances related to deferred tax assets	101	23.5%	—	—	—	—
Other, net	(1)	(0.2)%	(9)	(2.9)%	(15)	(4.1)%
Consolidated Income Tax Expense Related to Continuing Operations	$319	74.4%	$103	32.1%	$114	33.9%

Year ended December 31, 2013

PHI's consolidated effective income tax rate for the year ended December 31, 2013 of 74.4% reflects a charge of $56 million for changes in estimates and interest related to uncertain and effectively settled tax positions recorded in the first quarter of 2013 and the establishment of valuation allowances of $101 million in the first quarter of 2013 against certain deferred tax assets in PCI, which is now included in Corporate and Other. The income tax charge of $56 million is primarily related to the anticipated additional interest expense on estimated federal and state income tax obligations that was allocated to PHI's continuing operations resulting from a change in assessment of tax benefits associated with the former cross-border energy lease investments of PCI.

Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to both Consolidated Edison's cross-border lease transaction (as discussed in Note (19), "Discontinued Operations – Cross-Border Energy Lease Investments") and another taxpayer's structured transactions, (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI would be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. Further, during the fourth quarter of 2013, in light of additional court decisions in favor of the IRS involving other taxpayers, and after consideration of all relevant factors, management determined that it would abandon the further pursuit of these deferred tax assets, and these assets totaling $101 million were charged off against the previously established valuation allowances.

Year ended December 31, 2012

PHI's consolidated effective income tax rate for the year ended December 31, 2012 of 32.1% includes income tax benefits totaling $8 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. The rate for the year ended December 31, 2012 also reflects an increase in deductible asset removal costs for Pepco in 2012 related to a higher level of asset retirements.

Year ended December 31, 2011

PHI's consolidated effective income tax rate for the year ended December 31, 2011 of 33.9% includes income tax benefits totaling $5 million related to uncertain and effectively settled tax positions. In 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 and recorded the tax benefits, primarily in the second quarter of 2011.

In addition, as discussed further in Note (15), "Commitments and Contingencies – District of Columbia Tax Legislation," on June 14, 2011, the Council of the District of Columbia approved the Fiscal Year 2012 Budget Support Act of 2011 (the Budget Support Act). The Budget Support Act includes a provision that requires corporate taxpayers in the District of Columbia to calculate taxable income allocable or apportioned to the District by reference to the income and apportionment factors applicable to commonly controlled entities organized within the United States that are engaged in a unitary business. Previously, only the income of companies with direct nexus to the District of Columbia was taxed. As a result of the change, during 2011 PHI recorded additional state income tax expense of $2 million.

Components of Consolidated Deferred Tax Liabilities (Assets)

	At December 31,	
	2013	**2012**
	(millions of dollars)	
Deferred Tax Liabilities (Assets)		
Depreciation and other basis differences related to plant and equipment	$2,628	$2,299
Deferred electric service and electric restructuring liabilities	91	110
Cross-border energy lease investments	(6)	756
Federal and state net operating losses	(350)	(394)
Valuation allowances on state net operating losses	21	21
Pension and other postretirement benefits	135	128
Deferred taxes on amounts to be collected through future rates	75	58
Other (a)	285	204(b)
Total Deferred Tax Liabilities, net	2,879	3,182(b)
Deferred tax assets included in Current Assets	51	28
Deferred tax liabilities included in Other Current Liabilities	(2)	(2)
Total Consolidated Deferred Tax Liabilities, net non-current	$2,928	$3,208(b)

(a) PCI established valuation allowances against certain of these other deferred taxes totaling $101 million in the first quarter of 2013. Management determined during the fourth quarter of 2013 to abandon the further pursuit of the related deferred tax assets and, accordingly, these assets were charged off against the valuation allowances.

(b) The amounts for Other, Total Deferred Tax Liabilities, net and Total Consolidated Deferred Tax Liabilities, net non-current, are presented after the effect of the revision to prior period financial statements discussed in Note (2), " Significant Accounting Policies – Revision to Prior Period Financial Statements."

The net deferred tax liability represents the tax effect, at presently enacted tax rates, of temporary differences between the financial statement basis and tax basis of assets and liabilities. The portion of the net deferred tax liability applicable to PHI's utility operations, which has not been reflected in current service rates, represents income taxes recoverable through future rates, net, and is recorded as a Regulatory asset on the balance sheet. Federal and state net operating losses generally expire over 20 years from 2029 to 2032.

The Tax Reform Act of 1986 repealed the investment tax credit for property placed in service after December 31, 1985, except for certain transition property. Investment tax credits previously earned on Pepco's, DPL's and ACE's property continue to be amortized to income over the useful lives of the related property.

Reconciliation of Beginning and Ending Balances of Unrecognized Tax Benefits

	2013	2012	2011
		(millions of dollars)	
Balance as of January 1,	$200	$ 357	$395
Tax positions related to current year:			
Additions	3	1	2
Reductions	—	—	—
Tax positions related to prior years:			
Additions	646(a)	79	20
Reductions	(12)	(235)(b)	(57)
Settlements	(6)	(2)	(3)
Balance as of December 31,	$831	$ 200	$357

(a) These additions of unrecognized tax benefits in 2013 primarily relate to the cross-border energy lease investments of PCI.
(b) These reductions of unrecognized tax benefits in 2012 primarily relate to a resolution reached with the IRS for determining deductible mixed service costs for additions to property, plant and equipment.

Unrecognized Benefits That, If Recognized, Would Affect the Effective Tax Rate

Unrecognized tax benefits are related to tax positions that have been taken or are expected to be taken in tax returns that are not recognized in the financial statements because management has either measured the tax benefit at an amount less than the benefit claimed or expected to be claimed, or has concluded that it is not more likely than not that the tax position will be ultimately sustained. For the majority of these tax positions, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Unrecognized tax benefits at December 31, 2013 included $9 million that, if recognized, would lower the effective tax rate.

Interest and Penalties

PHI recognizes interest and penalties relating to its uncertain tax positions as an element of income tax expense. For the years ended December 31, 2013, 2012 and 2011, PHI recognized $125 million of pre-tax interest expense ($75 million after-tax), $23 million of pre-tax interest income ($14 million after-tax), and $23 million of pre-tax interest income ($14 million after-tax), respectively, as a component of income tax expense related to continuing and discontinued operations. As of December 31, 2013, 2012 and 2011, PHI had accrued interest receivable of $2 million, accrued interest receivable of $10 million and accrued interest payable of $4 million, respectively, related to effectively settled and uncertain tax positions.

Possible Changes to Unrecognized Tax Benefits

It is reasonably possible that the amount of unrecognized tax benefits with respect to PHI's uncertain tax positions will significantly increase or decrease within the next 12 months. In order to mitigate the cost of continued litigation of tax matters related to the former cross-border energy lease investments, PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues for open tax years 2001 through 2011. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014, which could significantly impact the balances of unrecognized tax benefits and the related interest accruals. At this time, it is estimated that there will be a $700 million to $800 million decrease in unrecognized tax benefits within the next 12 months. See Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," for additional discussion.

Tax Years Open to Examination

PHI's federal income tax liabilities for Pepco legacy companies for all years through 2002, and for Conectiv legacy companies for all years through 2002, have been determined by the IRS, subject to adjustment to the extent of any net operating loss or other loss or credit carrybacks from subsequent years. PHI has not reached final settlement with the IRS with respect to the cross-border energy lease deductions. The open tax years for the significant states where PHI files state income tax returns (District of Columbia, Maryland, Delaware, New Jersey, Pennsylvania and Virginia) are the same as for the Federal returns.

Final IRS Regulations on Repair of Tangible Property

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

Other Taxes

Other taxes for continuing operations are shown below. The annual amounts include $422 million, $426 million and $445 million for the years ended December 31, 2013, 2012 and 2011, respectively, related to Power Delivery, which are recoverable through rates.

	2013	2012	2011
	(millions of dollars)		
Gross Receipts/Delivery	$133	$135	$145
Property	77	75	71
County Fuel and Energy	153	160	170
Environmental, Use and Other	65	62	65
Total	$428	$432	$451

(12) STOCK-BASED COMPENSATION, DIVIDEND RESTRICTIONS, AND CALCULATIONS OF EARNINGS PER SHARE OF COMMON STOCK

Stock-Based Compensation

Pepco Holdings maintains the 2012 Long-Term Incentive Plan (2012 LTIP), the successor plan to the Long-Term Incentive Plan (LTIP), the objective of which is to increase shareholder value by providing long-term and equity incentives to reward officers, key employees and non-employee directors of Pepco Holdings and its subsidiaries and to increase the ownership of Pepco Holdings common stock by such individuals. Any officer, key employee or non-employee director of Pepco Holdings or its subsidiaries may be designated as a participant. Under these plans, awards to officers, key employees and non-employee directors may be in the form of restricted stock, restricted stock units, stock options, performance shares and/or units, stock appreciation rights, unrestricted stock and dividend equivalents. At inception, 10 million and 8 million shares of common stock were authorized for issuance under the LTIP and the 2012 LTIP, respectively. The LTIP expired in accordance with its terms in 2012 and no new awards may be granted thereunder.

Total stock-based compensation expense recorded in the consolidated statements of (loss) income for the years ended December 31, 2013, 2012 and 2011 was $12 million, $11 million and $6 million, respectively, all of which was associated with restricted stock unit and unrestricted stock awards.

No material amount of stock compensation expense was capitalized for the years ended December 31, 2013, 2012 and 2011.

Restricted Stock and Restricted Stock Unit Awards

Description of Awards

A number of programs have been established under the LTIP and the 2012 LTIP involving the issuance of restricted stock and restricted stock unit awards, including awards of performance-based restricted stock units, time-based restricted stock and restricted stock units, and retention restricted stock and restricted stock units. A summary of each of these programs is as follows:

- Under the performance-based program, performance criteria are selected and measured over the specified performance period. Depending on the extent to which the performance criteria are satisfied, the participants are eligible to earn shares of common stock at the end of the performance period, ranging from 25% to 200% of the target award, and dividend equivalents accrued thereon.
- Generally, time-based restricted stock and restricted stock unit award opportunities have a requisite service period of up to three years and, with respect to restricted stock awards, participants have the right to receive dividends on the shares during the vesting period. Under restricted stock unit awards, dividends are credited quarterly in the form of additional restricted stock units, which are paid when vested at the end of the service period.
- In January, April and September 2012, four retention awards in the form of 150,330 time-based and performance-based restricted stock units and 5,305 shares of unrestricted stock were granted to certain PHI executives. In January and February 2013, two retention awards in the form of 45,444 performance-based restricted stock units were granted to certain PHI executives. The time-based retention awards vest at varying rates over a period of three years, and the performance-based retention awards have a one-year performance period and are subject to the continued employment of the executive at the end of the performance period.
- In 2013 and 2012, restricted stock units totaling 37,735 and 40,749, respectively, were granted to PHI's non-employee directors under the 2012 LTIP. These restricted stock units vest over a service period which ends upon the first to occur of (i) one year after the date of grant or (ii) the date of the next annual meeting of stockholders. These awards represent the equity portion of the annual retainer paid to non-employee directors for their service as a director of PHI.

Activity for the year

The 2013 activity for non-vested, time-based restricted stock, restricted stock units and performance-based restricted stock unit awards, including retention awards, is summarized in the table below. For performance-based restricted stock unit awards, the table reflects awards projected, for purposes of computing the weighted average grant date fair value, to achieve 100% of targeted performance criteria for each outstanding award cycle.

	Number of Shares	Weighted Average Grant Date Fair Value
Balance as of January 1, 2013		
Time-based restricted stock	134,607	$ 16.56
Time-based restricted stock units	513,204	19.42
Performance-based restricted stock units	1,032,396	20.34
Total	1,680,207	
Granted during 2013		
Time-based restricted stock units	237,733	19.70
Performance-based restricted stock units	444,969	17.03
Total	682,702	
Vested during 2013		
Time-based restricted stock	(134,607)	16.56
Time-based restricted stock units	(123,021)	18.45
Performance-based restricted stock units	(314,995)	20.00
Total	(572,623)	
Forfeited during 2013		
Time-based restricted stock units	(44,362)	19.64
Performance-based restricted stock units	(92,540)	19.91
Total	(136,902)	
Balance as of December 31, 2013		
Time-based restricted stock	—	—
Time-based restricted stock units	583,554	19.34
Performance-based restricted stock units	1,069,830	19.06
Total	1,653,384	

Grants included in the table above reflect 2013 grants of performance-based and time-based restricted stock units, including retention awards. PHI recognizes compensation expense related to performance-based restricted stock unit awards and time-based restricted stock and restricted stock unit awards based on the fair value of the awards at date of grant. The fair value is based on the market value of PHI common stock at the date the award opportunity is granted. The estimated fair value of the performance-based awards is also a function of PHI's projected future performance relative to established performance criteria and the resulting payout of shares based on the achieved performance levels. PHI employed a Monte Carlo simulation to forecast PHI's performance relative to the performance criteria and to estimate the potential payout of shares under the performance-based awards.

The following table provides the weighted average grant date fair value per share of those awards granted during each of the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2011
Weighted average grant-date fair value of each unrestricted stock award granted during the year	$ —	$18.85	$ —
Weighted average grant-date fair value of each time-based restricted stock unit award granted during the year	$19.70	$19.69	$18.87
Weighted average grant-date fair value of each performance-based restricted stock unit award granted during the year	$17.03	$21.13	$19.56

As of December 31, 2013, there was approximately $11 million of future compensation cost (net of estimated forfeitures) related to restricted stock unit awards granted under the LTIP and the 2012 LTIP that PHI expects to recognize over a weighted-average period of approximately two years.

Stock Options

Stock options to purchase shares of PHI's common stock granted under the LTIP and the 2012 LTIP must have an exercise price at least equal to the fair market value of the underlying stock on the grant date. Stock options generally become exercisable on a specified vesting date or dates. All stock options must have an expiration date of no greater than ten years from the date of grant. No options have been granted under the LTIP or the 2012 LTIP since 2002. As of December 31, 2012, all outstanding stock options under predecessor plans have vested or expired. Total intrinsic value and tax benefits recognized for stock options exercised in 2012 and 2011 were immaterial.

Directors' Deferred Compensation

Under the Pepco Holdings' Executive and Director Deferred Compensation Plan, Pepco Holdings non-employee directors may elect to defer all or part of their cash retainer and meeting fees. Deferred retainer or meeting fees, at the election of the director, can be credited with interest at the prime rate or the return on selected investment funds or can be deemed invested in phantom shares of Pepco Holdings common stock on which dividend equivalent accruals are credited when dividends are paid on the common stock (or a combination of these options). All deferrals are settled in cash. The amount deferred by directors for each of the years ended December 31, 2013, 2012 and 2011 was not material.

Compensation expense recognized in respect of dividends and the increase in fair value for each of the years ended December 31, 2013, 2012 and 2011 was not material. The deferred compensation balances under this program were approximately $2 million and $1 million at December 31, 2013 and 2012, respectively.

A separate deferral option under the 2012 LTIP gives non-employee directors the right to elect to defer the receipt of common stock upon vesting of restricted stock unit awards.

Dividend Restrictions

PHI, on a stand-alone basis, generates no operating income of its own. Accordingly, its ability to pay dividends to its shareholders depends on dividends received from its subsidiaries. In addition to their future financial performance, the ability of PHI's direct and indirect subsidiaries to pay dividends is subject to limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and, in the case of ACE, the regulatory requirement that it obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of mortgage bonds and other long-term debt issued by the subsidiaries, and any other restrictions imposed in connection with the incurrence of liabilities; and (iii) certain provisions of ACE's charter that impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. Pepco, DPL and ACE have no shares of preferred stock outstanding at December 31, 2013. Currently, the capitalization ratio limitation to which ACE is subject and the restriction in the ACE charter do not limit ACE's ability to pay common stock dividends. PHI had approximately $595 million and $1,077 million of retained earnings free of restrictions at December 31, 2013 and 2012, respectively. These amounts represent the total retained earnings balances at those dates.

For the years ended December 31, 2013, 2012 and 2011, dividends paid by PHI's subsidiaries were as follows:

Subsidiary	2013	2012	2011
		(millions of dollars)	
Pepco (paid to PHI)	$ 46	$ 35	$ 25
DPL (paid to Conectiv)	30	—	60
ACE (paid to Conectiv)	60	35	—
Total	$136	$ 70	$ 85

Calculations of Earnings per Share of Common Stock

The numerator and denominator for basic and diluted earnings per share of common stock calculations are shown below.

	For the Years Ended December 31,		
	2013	2012	2011
	(millions of dollars, except per share data)		
Income (Numerator):			
Net income from continuing operations	$ 110	$ 218	$ 222
Net (loss) income from discontinued operations	(322)	67	35
Net (loss) income	$ (212)	$ 285	$ 257
Shares (Denominator) (in millions):			
Weighted average shares outstanding for basic computation:			
Average shares outstanding	246	229	226
Adjustment to shares outstanding	—	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	246	229	226
Net effect of potentially dilutive shares (a)	—	1	—
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	246	230	226
Basic earnings per share of common stock from continuing operations	$ 0.45	$ 0.95	$ 0.98
Basic (loss) earnings per share of common stock from discontinued operations	(1.31)	0.30	0.16
Basic (loss) earnings per share	$ (0.86)	$ 1.25	$ 1.14
Diluted earnings per share of common stock from continuing operations	$ 0.45	$ 0.95	$ 0.98
Diluted (loss) earnings per share of common stock from discontinued operations	(1.31)	0.29	0.16
Diluted (loss) earnings per share	$ (0.86)	$ 1.24	$ 1.14

(a) The number of options to purchase shares of common stock that were excluded from the calculation of diluted earnings per share as they are considered to be anti-dilutive were zero, zero and 14,900 for the years ended December 31, 2013, 2012 and 2011, respectively.

Equity Forward Transaction

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

Direct Stock Purchase and Dividend Reinvestment Plan

PHI maintains a Direct Stock Purchase and Dividend Reinvestment Plan (DRP) through which participants may reinvest cash dividends. In addition, participants can make purchases of shares of PHI common stock through the investment of not less than $25 per purchase nor more than $300,000 each calendar year. Shares of common stock purchased through the DRP may be new shares, treasury shares held by PHI, or, at the election of PHI, shares purchased in the open market. Approximately 2 million new shares were issued and sold under the DRP in each of 2013, 2012 and 2011.

Pepco Holdings Common Stock Reserved and Unissued

The following table presents Pepco Holdings' common stock reserved and unissued at December 31, 2013:

Name of Plan	Number of Shares
DRP	6,104,591
Pepco Holdings Long-Term Incentive Plan (a)	7,450,404
Pepco Holdings 2012 Long-Term Incentive Plan	7,971,832
Pepco Holdings Non-Management Directors Compensation Plan	457,211
Pepco Holdings Retirement Savings Plan	4,585,079
Total	26,569,117

(a) No further awards will be made under this plan.

(13) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Derivative Instruments

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

ACE was ordered to enter into the SOCAs by the NJBPU, and under the SOCAs, ACE would have received payments from or made 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. ACE began applying derivative accounting to two of its SOCAs as of June 30, 2012 because these generators cleared the 2015-2016 PJM capacity auction in May 2012. The fair value of the derivatives embedded in these SOCAs were deferred as regulatory assets or regulatory liabilities because the NJBPU allowed full recovery from ACE's distribution customers for any payments made by ACE, and ACE's distribution customers would be entitled to payments received by ACE. As further discussed in Note (7), "Regulatory Matters," in light of a Federal district court order, which ruled that the SOCAs are void, invalid and unenforceable, and ACE's subsequent termination of the SOCAs in the fourth quarter of 2013, ACE derecognized the derivative assets and derivative liabilities related to the SOCAs.

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

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

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

All derivative assets and liabilities available to be offset under master netting arrangements were netted as of December 31, 2013 and 2012. The amount of cash collateral that was offset against these derivative positions is as follows**:**

	December 31, 2013	December 31, 2012
	(millions of dollars)	
Cash collateral received from counterparties with the obligation to return	$ (1)	$ —

As of December 31, 2013 and 2012, all PHI cash collateral pledged related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Derivatives Designated as Hedging Instruments

Cash Flow Hedges

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. For the years ended December 31, 2013, 2012 and 2011, DPL had no net unrealized derivative losses and zero, zero and $5 million, respectively, of net realized losses associated with cash flow hedges recognized in the consolidated statements of (loss) income (through Fuel and purchased energy expense) that were deferred as Regulatory assets.

Cash Flow Hedges Included in Accumulated Other Comprehensive Loss

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

The tables below provide details regarding terminated cash flow hedges included in PHI's consolidated balance sheets as of December 31, 2013 and 2012. The data in the following tables indicate the cumulative net loss after-tax related to terminated cash flow hedges by contract type included in AOCL, the portion of AOCL expected to be reclassified to income during the next 12 months, and the maximum hedge or deferral term:

	As of December 31, 2013		
Contracts	**Accumulated Other Comprehensive Loss After-tax**	**Portion Expected to be Reclassified to Income during the Next 12 Months**	**Maximum Term**
	(millions of dollars)		
Interest rate	$ 9	$ 1	224 months
Total	$ 9	$ 1	

	As of December 31, 2012		
Contracts	**Accumulated Other Comprehensive Loss After-tax**	**Portion Expected to be Reclassified to Income during the Next 12 Months**	**Maximum Term**
	(millions of dollars)		
Interest rate	$ 10	$ 1	236 months
Total	$ 10	$ 1	

Other Derivative Activity

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 (prior to the order in October 2013 of a Federal district court as described in Note (7), "Regulatory Matters" which caused ACE to derecognize the derivative assets and derivative liabilities related to the SOCAs in the fourth quarter of 2013) pertaining to the SOCAs within which ACE's capacity derivatives are embedded. The following table indicates the net unrealized and net realized derivative gains and (losses) arising during the period associated with these derivatives that were recognized in the consolidated statements of (loss) income (through Fuel and purchased energy expense) and that were also deferred as Regulatory assets for the years ended December 31, 2013, 2012 and 2011:

	For the Year Ended December 31,		
	2013	2012	2011
	(millions of dollars)		
Net unrealized gain (loss) arising during the period	$ 4	$ (6)	$(13)
Net realized loss recognized during the period	(4)	(16)	(22)

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

	December 31, 2013		December 31, 2012	
Commodity	Quantity	Net Position	Quantity	Net Position
DPL—Natural gas (one Million British Thermal Units (MMBtu))	3,977,500	Long	3,838,000	Long
ACE—Capacity (MWs)	—	—	180	Long

Contingent Credit Risk Features

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

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

The gross fair values of DPL's derivative liabilities with credit risk-related contingent features as of December 31, 2013 and 2012, were zero and $4 million, respectively, before giving effect to offsetting transactions or collateral under master netting agreements. As of December 31, 2013 and 2012, DPL had posted no cash collateral against its gross derivative liability. If DPL's debt ratings had been downgraded below investment grade as of December 31, 2013 and 2012, DPL's net settlement amounts, including both the fair value of its derivative liabilities and its normal purchase and normal sale contracts would have been approximately zero and $2 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately zero and $2 million, respectively. 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, under which DPL is a borrower. As of December 31, 2013 and 2012, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the future liquidity needs of PHI's utility subsidiaries was $332 million and $477 million, respectively.

(14) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

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

The following tables set forth, by level within the fair value hierarchy, PHI's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. PHI's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

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

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2012 (millions of dollars)			
ASSETS				
Derivative instruments (b)				
Capacity (d)	$ 8	$ —	$ —	$ 8
Restricted cash equivalents				
Treasury fund	27	27	—	—
Executive deferred compensation plan assets				
Money market funds	17	17	—	—
Life insurance contracts	60	—	42	18
	$ 112	$ 44	$ 42	$ 26
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ —	$ —	$ 4
Capacity (d)	11	—	—	11
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
	$ 43	$ —	$ 28	$ 15

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

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

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

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

Executive deferred compensation plan assets and liabilities categorized as level 2 consist of life insurance policies and certain employment agreement obligations. The life insurance policies are categorized as level 2 assets because they are valued based on the assets underlying the policies, which consist of short-term cash equivalents and fixed income securities that are priced using observable market data and can be liquidated for the value of the underlying assets as of December 31, 2013. The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

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

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

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

- DPL applies a Black-Scholes model to value its options with inputs, such as forward price curves, contract prices, contract volumes, the risk-free rate and implied volatility factors that are based on a range of historical NYMEX option prices. DPL maintains valuation policies and procedures and reviews the validity and relevance of the inputs used to estimate the fair value of its options. As of December 31, 2013, all of these contracts classified as level 3 derivative instruments have settled.
- ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external valuation specialist to estimate annual zonal PJM capacity prices through the 2030-2031 auction. The capacity price forecast was based on various assumptions that impact the cost of constructing new generation facilities, including zonal load forecasts, zonal fuel and energy prices, generation capacity and transmission planning, and environmental legislation and regulation. ACE reviewed the assumptions and resulting capacity price forecast for reasonableness. ACE used the capacity price forecast to estimate future cash flows. A significant change in the forecasted prices would have a significant

impact on the estimated fair value of the SOCAs. ACE employed a discount rate reflective of the estimated weighted average cost of capital for merchant generation companies since payments under the SOCAs are contingent on providing generation capacity. As further discussed in Note (7), "Regulatory Matters," ACE derecognized the derivative assets and derivative liabilities related to the SOCAs in the fourth quarter of 2013.

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

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

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

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

Reconciliations of the beginning and ending balances of PHI's fair value measurements using significant unobservable inputs (Level 3) for the years ended December 31, 2013 and 2012 are shown below:

	Year Ended December 31, 2013			Year Ended December 31, 2012		
	Natural Gas	Life Insurance Contracts	Capacity	Natural Gas	Life Insurance Contracts	Capacity
	(millions of dollars)			(millions of dollars)		
Balance as of January 1	$ (4)	$ 18	$ (3)	$ (15)	$ 17	$ —
Total gains (losses) (realized and unrealized):						
Included in income	—	4	—	—	4	—
Included in accumulated other comprehensive loss	—	—	—	—	—	—
Included in regulatory liabilities	—	—	3	(2)	—	(3)
Purchases	—	—	—	—	—	—
Issuances	—	(3)	—	—	(3)	—
Settlements	4	—	—	13	—	—
Transfers in (out) of level 3	—	—	—	—	—	—
Balance as of December 31	$ —	$ 19	$ —	$ (4)	$ 18	$ (3)

The breakdown of realized and unrealized gains or (losses) 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:

	Year Ended December 31, 2013	2012
	(millions of dollars)	
Total net gains included in income for the period	$ 4	$ 4
Change in unrealized gains relating to assets still held at reporting date	$ 4	$ 4

Other Financial Instruments

The estimated fair values of PHI's Long-term debt instruments that are measured at amortized cost in PHI's consolidated financial statements and the associated level of the estimates within the fair value hierarchy as of December 31, 2013 and 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. PHI's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

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

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

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

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

Description	Total	Fair Value Measurements at December 31, 2012 Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (b)	$ 5,004	$ —	$ 4,517	$ 487
Transition Bonds (c)	341	—	341	—
Long-term project funding	13	—	—	13
	$ 5,358	$ —	$ 4,858	$ 500

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

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

(15) COMMITMENTS AND CONTINGENCIES

General Litigation and Other Matters

From time to time, PHI and its subsidiaries are named as defendants in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. PHI and each of its subsidiaries are self-insured against such claims up to a certain self-insured retention amount and maintain insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, PHI’s contracts with its vendors generally require the vendors to name PHI and/or its subsidiaries as additional insureds for the amounts at least equal to PHI’s self-insured retention. Further, PHI’s contracts with its vendors require the vendors to indemnify PHI for various acts and activities that may give rise to claims against PHI. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on PHI’s or its subsidiaries’ financial condition, results of operations or cash flows. At December 31, 2013, PHI had loss contingency liabilities for general litigation totaling approximately $30 million (including amounts related to the matters specifically described below) and the portion of these loss contingency liabilities in excess of the self-insured retention amount was substantially offset by insurance receivables.

Pepco Substation Injury Claim

In May 2013, a contract worker erecting a scaffold at a Pepco substation came into contact with an energized station service feeder and suffered serious injuries. In August 2013, the individual filed suit against Pepco in the Circuit Court for Montgomery County, Maryland, seeking damages for medical expenses, loss of future earning capacity, pain and suffering and the cost of a life care plan aggregating to a maximum claim of approximately $28.1 million. Discovery is ongoing in the case and, if a settlement cannot be reached with respect to this matter, a trial is expected to begin in October 2014. Pepco has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident, including the policies of the contractor performing the scaffold work (which name Pepco as an additional insured), will offset substantially all of Pepco’s costs associated with the resolution of this matter, including Pepco’s self-insured retention amount. At December 31, 2013, Pepco has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of December 31, 2013. Pepco has also concluded as of December 31, 2013 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable offsetting substantially all of the related loss contingency liability.

ACE Asbestos Claim

In September 2011, an asbestos complaint was filed in the New Jersey Superior Court, Law Division, against ACE (among other defendants) asserting claims under New Jersey's Wrongful Death and Survival statutes. The complaint, filed by the estate of a decedent who was the wife of a former employee of ACE, alleges that the decedent's mesothelioma was caused by exposure to asbestos brought home by her husband on his work clothes. New Jersey courts have recognized a cause of action against a premise owner in a so-called "take home" case if it can be shown that the harm was foreseeable. In this case, the complaint seeks recovery of an unspecified amount of damages for, among other things, the decedent's past medical expenses, loss of earnings, and pain and suffering between the time of injury and death, and asserts a punitive damage claim. At December 31, 2013, ACE has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of December 31, 2013. However, due to the inherent uncertainty of litigation, ACE is unable to estimate a maximum amount of possible loss because the damages sought are indeterminate and the matter involves facts that ACE believes are distinguishable from the facts of the "take-home" cause of action recognized by the New Jersey courts.

ACE Electrical Contact Injury Claims

In October 2010, a farm combine came into and remained in contact with a primary electric line in ACE's service territory in New Jersey. As a result, two individuals operating the combine received fatal electrical contact injuries. While attempting to rescue those two individuals, another individual sustained third-degree burns to his torso and upper extremities. In September 2012, the individual who received third-degree burns filed suit in New Jersey Superior Court, Salem County. In October 2012, additional suits were filed in the same court by or on behalf of the estates of the deceased individuals. Plaintiffs in each of the cases are seeking indeterminate damages and allege that ACE was negligent in the design, construction, erection, operation and maintenance of its poles, power lines, and equipment, and that ACE failed to warn and protect the public from the foreseeable dangers of farm equipment contacting electric lines. Discovery is ongoing in this matter and the litigation involves a number of other defendants and the filing of numerous cross-claims. ACE has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident will offset ACE's costs associated with the resolution of this matter in excess of ACE's self-insured retention amount. At December 31, 2013, ACE has concluded that a loss is probable with respect to these claims and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of December 31, 2013. ACE has also concluded as of December 31, 2013 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable offsetting substantially all of the loss contingency liability in excess of ACE's self-insured retention amount.

Pepco Energy Services Billing Claims

During 2012, Pepco Energy Services received letters on behalf of two school districts in Maryland, which claim that invoices in connection with electricity supply contracts contained certain allegedly unauthorized charges, totaling approximately $7 million. The school districts also claim additional compounded interest totaling approximately $9 million. Although no litigation involving Pepco Energy Services related to these claims has commenced, in August and September 2013, Pepco Energy Services received correspondence from the Superintendent of each of the school districts advising of the intention to render a decision regarding an unresolved dispute between the school district and Pepco Energy Services. Pepco Energy Services filed timely answers to the Superintendents challenging the authority of the respective Superintendents to render decisions on the claims and also disputing the merits of the allegations regarding unauthorized charges as well as the claims of entitlement to compounded interest. To date, one of the two districts has submitted a late response to the answer of Pepco Energy Services maintaining that its Superintendent does have authority to render a decision but acknowledging the availability of administrative and judicial review of the merits of any decision. The response of the other district is overdue. As of December 31, 2013, Pepco Energy Services has concluded that a loss is reasonably possible with respect to these claims, but the amount of loss, if any, is not reasonably estimable.

Environmental Matters

PHI, through its subsidiaries, is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of PHI's utility subsidiaries, environmental clean-up costs incurred by Pepco, DPL and ACE generally are included by each company in its respective cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies described below of PHI and its subsidiaries at December 31, 2013 are summarized as follows:

		Legacy Generation			
	Transmission and Distribution	Regulated	Non-Regulated	Other	Total
		(millions of dollars)			
Balance as of January 1	$ 15	$ 7	$ 5	$ 2	$ 29
Accruals	5	—	—	1	6
Payments	(1)	(1)	—	(3)	(5)
Balance as of December 31	19	6	5	—	30
Less amounts in Other Current Liabilities	3	1	—	—	4
Amounts in Other Deferred Credits	$ 16	$ 5	$ 5	$ —	$ 26

Conectiv Energy Wholesale Power Generation Sites

In July 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 PHI's estimates, the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million. The amount accrued by PHI for the ISRA-required remediation activities at the nine generating facility sites is included in the table above in the column entitled "Legacy Generation – Non-Regulated."

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

Franklin Slag Pile Site

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

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

Peck Iron and Metal Site

EPA informed Pepco in a May 2009 letter that Pepco may be a PRP under CERCLA with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that 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 in November 2009, EPA placed the Peck Iron and Metal site on the National Priorities List. The National Priorities List, among other things, serves as a guide to EPA in determining which sites warrant further investigation to assess the nature and extent of the human health and environmental risks associated with a site. In September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Ward Transformer Site

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

Benning Road Site

In September 2010, PHI received a letter from EPA identifying the Benning Road location, consisting of a generation facility operated by Pepco Energy Services until the facility was deactivated in June 2012, and a transmission and distribution facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The letter stated that the principal contaminants of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the District of Columbia Department of the Environment (DDOE), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DDOE's selection of a remedial action for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DDOE will look to the companies to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

In December 2012, DDOE approved the RI/FS work plan. RI/FS field work commenced in January 2013 and is still in progress. In October 2013, Pepco and Pepco Energy Services submitted a work plan addendum for approval by DDOE identifying the location of groundwater monitoring wells to be installed at the site and sampled as the last phase of the field work. The work plan addendum has been revised in response to comments from DDOE, and it is expected that the addendum will be approved and the next phase of field work will commence before the end of the first quarter of 2014. Once all of the field work has been completed, Pepco and Pepco Energy Services will prepare RI/FS reports for review and approval by DDOE after solicitation and consideration of public comment. The next status report to the court is due on May 24, 2014.

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

Indian River Oil Release

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

Potomac River Mineral Oil Release

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

Beginning in March 2011, DDOE issued a series of compliance directives requiring Pepco to prepare an incident report, provide certain records, and prepare and implement plans for sampling surface water and river sediments and assessing ecological risks and natural resources damages. Pepco completed field sampling during the fourth quarter of 2011 and submitted sampling results to DDOE during the second quarter of 2012. Pepco is continuing discussions with DDOE regarding the need for any further response actions but expects that additional monitoring of shoreline sediments may be required.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened enforcement action, including civil penalties, for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. Pepco and DDOE have reached an agreement in principle that would consist of a combination of a civil penalty and Supplemental Environmental Projects (SEPs) with a total cost to Pepco of approximately $1 million. DDOE has endorsed Pepco's proposed SEP involving the installation and operation of a trash collection system at a stormwater outfall that drains to the Anacostia River. DDOE and Pepco are completing negotiations on the text of a consent decree to document the settlement of DDOE's enforcement action and a written statement of work describing the details of the trash collection system SEP. It is expected that the consent decree will be filed with the District of Columbia Superior Court by the end of the first quarter of 2014, with a request that the court approve the consent decree following a period of at least 30 days for public comment. Discussions will proceed separately with DDOE and the federal resource trustees regarding the settlement of a natural resource damage (NRD) claim under federal law. Based on discussions to date, PHI and Pepco do not believe that the resolution of DDOE's enforcement action or the federal NRD claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

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

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

Metal Bank Site

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

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

Brandywine Fly Ash Disposal Site

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

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

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

Watts Branch Insulating Fluid Release

On September 13, 2013, a Washington Metropolitan Area Transit Authority contractor damaged a Pepco underground transmission feeder while drilling a grout column for a subway tunnel under a city street. The damage caused the release of approximately 11,250 gallons of insulating fluid, a small amount of which reached the Watts Branch, a tributary of the Anacostia River. The U.S. Coast Guard (USCG) issued a notice of federal interest for an oil pollution incident, informing Pepco of its responsibility under the Oil Pollution Act of 1990 for removal costs and damages from the release. In addition, on September 25, 2013, DDOE issued a compliance directive that required Pepco to prepare an incident investigation report describing the events leading up to the release. The compliance directive also required Pepco to prepare work plans for sampling the insulating fluid and for developing and implementing a biological assessment and physical habitat quality assessment to be conducted in Watts Branch. Pepco prepared the incident investigation report and work plans and submitted them to DDOE and USCG. In December 2013, Pepco received and responded to an EPA information request regarding this incident.

PHI and Pepco believe that a loss in this matter is probable; however, the costs to resolve this matter are expected to be less than $1 million and are being expensed as incurred. PHI and Pepco further believe that the costs incurred will be recoverable from the party or parties responsible for the release. On December 4, 2013, the USCG delivered a Notice of Violation with respect to this matter, which imposed a $3,000 penalty on Pepco, which Pepco has paid.

PHI's Cross-Border Energy Lease Investments

As discussed in Note (19), "Discontinued Operations – Cross-Border Energy Lease Investments," PHI held a portfolio of cross-border energy lease investments involving public utility assets located outside of the United States. Each of these investments was comprised of multiple leases and was structured as a sale and leaseback transaction commonly referred to by the IRS as a sale-in, lease-out, or SILO, transaction.

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

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. While PHI believes that its tax position with regard to its cross-border energy lease investments is appropriate, after analyzing the recent U.S. Court of Appeals ruling, PHI determined in the first quarter of 2013 that its tax position with respect to the tax benefits associated with the cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded a non-cash after-tax charge of $377 million in the first quarter of 2013 (as discussed in Note (19), "Discontinued Operations – Cross-Border Energy Lease Investments"), consisting of a charge to reduce the carrying value of the cross-border energy lease investments and a charge to reflect the anticipated additional interest expense related to changes in PHI's estimated federal and state income tax obligations for the period over which the tax benefits ultimately may be disallowed. PHI had also previously made certain business assumptions regarding foreign investment opportunities available at the end of the full lease terms. During the first quarter of 2013, management believed that its conclusions regarding these business assumptions were no longer supportable, and the tax effects of this change in conclusion were included in the charge. While the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due, PHI believes that it is more likely than not that no such penalty will be incurred, and therefore no amount for any potential penalty was included in the charge recorded in the first quarter of 2013.

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

In order to mitigate the cost of continued litigation related to the cross-border energy lease investments, PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues for open tax years 2001 through 2011, including the cross-border energy lease issue. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014. If a settlement of all tax issues or a standalone settlement on the leases is not reached, PHI may move forward with its litigation with the IRS. Further discovery in the case is stayed until April 24, 2014, pursuant to an order issued by the court on January 30, 2014.

District of Columbia Tax Legislation

In 2011, the Council of the District of Columbia approved the Budget Support Act which requires that corporate taxpayers in the District of Columbia calculate taxable income allocable or apportioned to the District of Columbia by reference to the income and apportionment factors applicable to commonly controlled entities organized within the United States that are engaged in a unitary business. In the aggregate, this new tax reporting method reduced pre-tax earnings for the year ended December 31, 2011 by $7 million ($5 million after-tax) as further discussed in Note (11), "Income Taxes," and Note (19), "Discontinued Operations." During 2012, the District of Columbia Office of Tax and Revenue adopted regulations to implement this reporting method. PHI has analyzed these regulations and determined that the regulations did not impact PHI's results of operations for the years ended December 31, 2013 and 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 December 31, 2013, PHI and its subsidiaries were parties to a variety of agreements pursuant to which they were guarantors for standby letters of credit, energy procurement obligations, and other commitments and obligations. The commitments and obligations, in millions of dollars, were as follows:

	Guarantor				
	PHI	Pepco	DPL	ACE	Total
	(millions of dollars)				
Energy procurement obligations of Pepco Energy Services (a)	$46	$—	$—	$—	$ 46
Guarantees associated with disposal of Conectiv Energy assets (b)	13	—	—	—	13
Guaranteed lease residual values (c)	3	5	7	4	19
Total	$62	$ 5	$ 7	$ 4	$ 78

(a) PHI has continued contractual commitments for performance and related payments of Pepco Energy Services primarily to Independent System Operators and distribution companies.
(b) Represents guarantees by PHI of Conectiv Energy's derivatives portfolio transferred in connection with the disposition of Conectiv Energy's wholesale business. The derivative portfolio guarantee is currently $13 million and covers Conectiv Energy's performance prior to the assignment. This guarantee will remain in effect until the end of 2015.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $55 million, $10 million of which is a guarantee by PHI, $15 million by Pepco, $17 million by DPL and $13 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

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

Energy Savings Performance Contracts

Pepco Energy Services has a diverse portfolio of energy savings performance contracts that are associated with the installation of energy savings equipment or combined heat and power facilities for federal, state and local government customers. As part of the energy savings 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 December 31, 2013, the remaining notional amount of Pepco Energy Services' energy savings guarantees over the life of the multi-year performance contracts on: i) completed projects was $252 million with the longest guarantee having a remaining term of 12 years; and, ii) projects under construction was $187 million with the longest guarantee having a term of 23 years after completion of construction. On an annual basis, Pepco Energy Services undertakes a measurement and verification process to determine the amount of energy savings for the year and whether there is any shortfall in the annual energy savings compared to the guaranteed amount.

As of December 31, 2013, Pepco Energy Services had a performance guarantee contract associated with the production at a combined heat and power facility that is under construction totaling $15 million in notional value over 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 December 31, 2013, Pepco Energy Services had an accrued liability of $1 million for its energy savings contracts that it established during 2012. There was no significant change in the type of contracts issued during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Dividends

On January 23, 2014, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable March 31, 2014, to stockholders of record on March 10, 2014.

Contractual Obligations

Power Purchase Contracts

As of December 31, 2013, Pepco Holdings' contractual obligations under non-derivative power purchase contracts were $278 million in 2014, $562 million in 2015 to 2016, $486 million in 2017 to 2018, and $1,386 million in 2019 and thereafter.

Lease Commitments

Rental expense for operating leases was $54 million, $52 million and $46 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Total future minimum operating lease payments for Pepco Holdings as of December 31, 2013, are $44 million in 2014, $42 million in 2015, $39 million in 2016, $36 million in 2017, $37 million in 2018 and $342 million thereafter.

(16) VARIABLE INTEREST ENTITIES

PHI is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if PHI or a subsidiary is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. PHI performs a qualitative analysis to determine whether a variable interest provides a controlling financial interest in a VIE. Set forth below are the relationships with respect to which PHI conducted a VIE analysis as of December 31, 2013:

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 December 31, 2013, PHI, through its DPL subsidiary, is a party to three land-based wind PPAs in the aggregate amount of 128 MWs and one solar PPA with a 10 MW facility. Each of the facilities associated with these PPAs is operational, and DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and solar renewable energy credits (SRECs) from the solar facility up to certain amounts (as set forth below) at rates that are primarily fixed under the respective PPA. PHI and DPL have concluded that while VIEs exist under these contracts, consolidation is not required for any of these PPAs under the FASB guidance on the consolidation of variable interest entities as DPL is not the primary beneficiary. DPL has not provided financial or other support under these arrangements that it was not previously contractually required to provide during the periods presented, nor does DPL have any intention to provide such additional support.

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

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from the second wind facility through 2031 in amounts not to exceed 40 MWs, and from the third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's purchases under the three wind PPAs totaled $30 million, $27 million and $18 million for the years ended December 31, 2013, 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 $3 million, $2 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to fuel cell facilities totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL would be an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour (MWh) of energy produced by the fuel cell facilities over 21 years. DPL has no obligation to the qualified fuel cell provider other than to remit payments collected from its distribution customers pursuant to the tariff. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. At December 31, 2013 and 2012, 15 MWs and 3 MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $23 million and $4 million to distribution customers during the years ended December 31, 2013 and 2012, respectively. PHI and DPL have concluded that while a VIE exists under this arrangement, consolidation is not required for this arrangement under the FASB guidance on consolidation of variable interest entities as DPL is not the primary beneficiary.

ACE Power Purchase Agreements

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

Because ACE has no equity or debt invested in the NUGs, the maximum exposure to loss relates primarily to any above-market costs incurred for power. Due to unpredictability in the PPAs pricing for purchased energy, PHI and ACE are unable to quantify the maximum exposure to loss. The power purchase costs are recoverable from ACE's customers through regulated rates. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the years ended December 31, 2013, 2012 and 2011 were approximately $221 million, $206 million and $218 million, respectively, of which approximately $206 million, $201 million and $206 million, respectively, consisted of power purchases under the PPAs.

ACE Funding

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

(17) ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Year Ended December 31,		
	2013	2012	2011
Balance as of January 1	$ (48)	$ (63)	$ (106)
Treasury Lock			
Balance as of January 1	(10)	(10)	(11)
Amount of pre-tax loss reclassified to Interest expense	1	—	1
Income tax benefit	—	—	—
Balance as of December 31	(9)	(10)	(10)
Pension and Other Postretirement Benefits			
Balance as of January 1	(32)	(24)	(17)
Amount of amortization of net prior service cost and actuarial loss reclassified to Other operation and maintenance expense	5	5	3
Amount of net prior service cost and actuarial gain (loss) arising during the year	8	(19)	(14)
Income tax benefit (expense)	6	(6)	(4)
Balance as of December 31	(25)	(32)	(24)
Commodity Derivatives			
Balance as of January 1	(6)	(29)	(78)
Amount of net pre-tax loss reclassified to (Loss) income from discontinued operations before income tax	10	39	81
Income tax benefit	4	16	32
Balance as of December 31	—	(6)	(29)
Balance as of December 31	$ (34)	$ (48)	$ (63)

(18) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The quarterly data presented below reflect all adjustments necessary in the opinion of management for a fair presentation of the interim results. Quarterly data normally vary seasonally because of temperature variations and differences between summer and winter rates. The totals of the four quarterly basic and diluted earnings per common share amounts may not equal the basic and diluted earnings per common share for the year due to changes in the number of shares of common stock outstanding during the year.

	2013				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(millions, except per share amounts)				
Total Operating Revenue	$1,180	$1,051	$1,344	$1,091	$4,666
Total Operating Expenses	1,047	906	1,109	936(a)	3,998
Operating Income	133	145	235	155	668
Other Expenses	(59)	(62)	(60)	(58)	(239)
Income From Continuing Operations Before Income Tax Expense	74	83	175	97	429
Income Tax Expense Related to Continuing Operations	185(b)	30	65	39	319
Net (Loss) Income From Continuing Operations	(111)	53	110	58	110
(Loss) Income from Discontinued Operations, net of taxes	(319)	(11)	8	—	(322)
Net (Loss) Income	$ (430)	$ 42	$ 118	$ 58	$ (212)
Basic and Diluted Earnings Per Share of Common Stock					
(Loss) Earnings Per Share of Common Stock from Continuing Operations	(0.47)	0.21	0.44	0.23	0.45
(Loss) Earnings Per Share of Common Stock from Discontinued Operations	(1.35)	(0.04)	0.04	—	(1.31)
(Loss) Earnings Per Share of Common Stock	(1.82)	0.17	0.48	0.23	(0.86)
Cash Dividends Per Share of Common Stock	0.27	0.27	0.27	0.27	1.08

(a) Includes a pre-tax impairment loss of $4 million ($3 million after-tax) at Pepco Energy Services associated with a landfill gas-fired electric generation facility.
(b) Includes an income tax charge of $56 million (after-tax) primarily associated with interest on uncertain and effectively settled tax positions and an income tax charge of $101 million associated with the establishment of valuation allowances against certain deferred tax assets of PCI.

	2012				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(millions, except per share amounts)				
Total Operating Revenue (a)	$1,123	$1,057	$1,389	$1,056	$4,625
Total Operating Expenses (a)(b)	1,010	932	1,188	954	4,084
Operating Income	113	125	201	102	541
Other Expenses	(54)	(52)	(57)	(57)	(220)
Income From Continuing Operations Before Income Tax Expense	59	73	144	45	321
Income Tax Expense Related to Continuing Operations	9	26	57	11	103
Net Income From Continuing Operations	50	47	87	34	218
Income from Discontinued Operations, net of taxes	18	15	25	9	67
Net Income	$ 68	$ 62	$ 112	$ 43	$ 285
Basic Earnings Per Share of Common Stock					
Earnings Per Share of Common Stock from Continuing Operations	0.22	0.20	0.38	0.15	0.95
Earnings Per Share of Common Stock from Discontinued Operations	0.08	0.07	0.11	0.03	0.30
Basic Earnings Per Share of Common Stock	0.30	0.27	0.49	0.18	1.25
Diluted Earnings Per Share of Common Stock					
Earnings Per Share of Common Stock from Continuing Operations	0.22	0.20	0.38	0.15	0.95
Earnings Per Share of Common Stock from Discontinued Operations	0.08	0.07	0.11	0.03	0.29
Diluted Earnings Per Share of Common Stock	0.30	0.27	0.49	0.18	1.24
Cash Dividends Per Share of Common Stock	0.27	0.27	0.27	0.27	1.08

(a) Includes $9 million of intra-company revenues (and associated costs) previously eliminated in consolidation which will continue to be recognized from third parties subsequent to the completion of the wind-down of the Pepco Energy Services' retail electric and natural gas supply businesses.
(b) Includes impairment losses of $12 million pre-tax ($7 million after-tax) at Pepco Energy Services associated primarily with investments in landfill gas-fired electric generation facilities, and the combustion turbines at Buzzard Point.

(19) DISCONTINUED OPERATIONS

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

	For the Year Ended December 31,		
	2013	2012	2011
	(millions of dollars)		
Cross-border energy lease investments	$ (327)	$ 41	$ 36
Pepco Energy Services' retail electric and natural gas supply businesses	5	26	2
Conectiv Energy	—	—	(3)
(Loss) income from discontinued operations, net of income taxes	$ (322)	$ 67	$ 35

Cross-Border Energy Lease Investments

Between 1994 and 2002, PCI entered into cross-border energy lease investments consisting of hydroelectric generation facilities, coal-fired electric generation facilities and natural gas distribution networks located outside of the United States. Each of these lease investments was structured as a sale and leaseback transaction commonly referred to as a sale-in, lease-out, or SILO, transaction. As of December 31, 2013 and 2012, the lease portfolio consisted of zero investments and six investments, respectively, with a net investment value of zero and $1,237 million, respectively.

During the second and third quarters of 2013, PHI terminated early all of its interests in the six remaining lease investments. PHI received aggregate net cash proceeds from these early terminations of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. As a result, PHI has reported the results of operations of the cross-border energy lease investments as discontinued operations in all periods presented in the accompanying consolidated statements of (loss) income. Further, the assets and liabilities related to the cross-border energy lease investments are reported as held for disposition as of each date in the accompanying consolidated balance sheets.

Operating Results

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

	For the Year Ended December 31,		
	2013	2012	2011
	(millions of dollars)		
Operating revenue from PHI's cross-border energy lease investments	$ 7	$ 50	$ 55
Non-cash charge to reduce carrying value of PHI's cross-border energy lease investments	(373)	—	(7)
Total operating revenue	$ (366)	$ 50	$ 48
(Loss) income from operations of discontinued operations, net of income taxes (a)	$ (325)	$ 32	$ 33
Net (losses) gains associated with the early termination of the cross-border energy lease investments, net of income taxes (b)	(2)	9	3
(Loss) income from discontinued operations, net of income taxes	$ (327)	$ 41	$ 36

(a) Includes income tax (benefit) expense of approximately $(44) million, $5 million and $(2) million for the years ended December 31, 2013, 2012 and 2011, respectively.
(b) Includes income tax (benefit) expense of approximately $(1) million, $30 million and $36 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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

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

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

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

During 2012, PHI entered into early termination agreements with two lessees involving all of the leases comprising one of the original eight lease investments. The early terminations of the leases were negotiated at the request of the lessees. 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 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. 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 leases terminated in 2012 and 2011, 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 recognized the related tax consequences by recording income tax charges in the amounts of $16 million and $22 million for the years ended December 31, 2012 and 2011, respectively. The after-tax gains on the lease terminations were $9 million and $3 million for the years ended December 31, 2012 and 2011, respectively, including the income tax charges discussed above and an income tax provision at the statutory Federal rate of $14 million for each early lease termination. As of December 31, 2012, PHI had no intent to terminate early any other leases in the lease portfolio and maintained its assertion that the foreign earnings recognized at the end of the lease term with respect to certain of these remaining leases will remain invested abroad. See Note (15), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," regarding a subsequent change in management's intent.

PHI was required to assess on a periodic basis the likely outcome of tax positions relating to its cross-border energy lease investments and, if there was a change or a projected change in the timing of the tax benefits generated by the transactions, PHI was required to recalculate the value of its net investment. In that regard, PHI modified its tax cash flow assumptions in 2011 and recorded a non-cash pre-tax charge of $7 million to reduce the carrying value of its net investment. The tax cash flow assumptions changed in 2011 as a result of the enactment of tax regulations in the District of Columbia to implement the mandatory unitary combined reporting method. The charge was recorded as a reduction in cross-border energy lease investment revenue in 2011.

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

Balance Sheet Information

As of December 31, 2013 and 2012, the assets held for disposition and liabilities associated with assets held for disposition related to the cross-border energy lease investments are:

	2013	2012
	(millions of dollars)	
Scheduled lease payments to PHI, net of non-recourse debt	$ —	$ 1,852
Less: Unearned and deferred income	—	(615)
Assets held for disposition	$ —	$ 1,237
Liabilities associated with assets held for disposition	$ —	$ 1

To ensure credit quality, PHI regularly monitored the financial performance and condition of the lessees under the former cross-border energy lease investments. Changes in credit quality were assessed to determine whether they affected the carrying value of the leases. PHI compared each lessee's performance to annual compliance requirements set by the terms and conditions of the leases and compared published credit ratings to minimum credit rating requirements in the leases for lessees with public credit ratings. In addition, PHI routinely met with senior executives of the lessees to discuss their company and asset performance. If the annual compliance requirements or minimum credit ratings were not met, remedies would have been available under the leases.

The table below shows PHI's net investment in these leases by the published credit ratings of the lessees as of December 31:

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

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

Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services

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

Operating Results

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

	For the Year Ended December 31,		
	2013	2012	2011
	(millions of dollars)		
Operating revenue	$84	$415	$954
Income from operations of discontinued operations, net of income taxes	$ 4	$ 26	$ 2
Net gains associated with accelerated disposition of retail electric and natural gas contracts, net of income taxes	1	—	—
Income from discontinued operations, net of income taxes (a)	$ 5	$ 26	$ 2

(a) Includes income tax expense of approximately $3 million, $18 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Balance Sheet Information

As of December 31, 2013 and 2012, the retail electric and natural gas supply businesses of Pepco Energy Services had net accounts receivable of zero and $33 million, respectively, inventory assets of $1 million and $3 million, respectively, gross derivative assets of zero and $1 million respectively, other current assets of zero and $1 million, respectively, accrued liabilities of $1 million and $20 million, respectively, gross derivative liabilities of zero and $21 million, respectively, exclusive of the collateral pledged by Pepco Energy Services against the derivative liabilities, and other current liabilities of zero and $1 million, respectively. As of December 31, 2012, the derivative assets were considered level 1 within the fair value hierarchy, and $11 million and $10 million of the derivative liabilities were considered levels 1 and 2, respectively, within the fair value hierarchy.

Derivative Instruments and Hedging Activities

Derivatives were used by the retail electric and natural gas supply businesses of Pepco Energy Services to hedge commodity price risk.

The retail electric and natural gas supply businesses of Pepco Energy Services entered into energy commodity contracts in the form of natural gas futures, swaps, options and forward contracts to hedge commodity price risk in connection with the purchase of physical natural gas and electricity for distribution to customers. The primary risk management objective was to manage the spread between retail sales commitments and the cost of supply used to service those commitments to ensure stable cash flows and lock in favorable prices and margins when they became available. There were no derivatives for Pepco Energy Services as of December 31, 2013.

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

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

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

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

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), the retail electric and natural gas supply businesses of Pepco Energy Services offset the fair value amounts recognized for derivative instruments and the fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. No derivative assets or liabilities were available to be offset under master netting agreements as of December 31, 2012. Cash collateral pledged to counterparties with the right to reclaim of $18 million (including cash deposits on commodity brokerage accounts) was offset against these derivative positions.

As of December 31, 2013 and 2012, all cash collateral pledged by the retail electric and natural gas supply businesses related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Derivatives Designated as Hedging Instruments

At December 31, 2012, the cumulative net pre-tax loss related to effective cash flow hedges of the retail electric and natural gas supply businesses of Pepco Energy Services included in AOCL was $10 million ($6 million after-tax). With the assumption by a third party, on April 1, 2013, of all the rights and obligations of the derivative contracts associated with the retail natural gas supply business, and the completion of the wind-down of the retail electric supply business in the second quarter of 2013, all of the losses deferred in AOCL associated with derivatives that Pepco Energy Services had previously designated as cash flow hedges were reclassified into income. As a result, a loss of $10 million ($6 million after-tax) was reclassified from AOCL to (Loss) income from discontinued operations, net of income taxes, for the year ended December 31, 2013.

Other Derivative Activity

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

For the years ended December 31, 2013, 2012, and 2011, the amount of the derivative gain (loss) for the retail electric and natural gas supply businesses of Pepco Energy Services recognized in (Loss) income from discontinued operations, net of income taxes is provided in the table below:

	For the Year Ended December 31,		
	2013	2012	2011
	(millions of dollars)		
Reclassification of mark-to-market to realized on settlement of contracts	$ 10	$27	$—
Unrealized mark-to-market loss	—	(3)	(30)
Total net gain (loss)	$ 10	$24	$ (30)

As of December 31, 2013, the retail electric and natural gas supply businesses of Pepco Energy Services had no outstanding commodity forward contracts or derivative positions.

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

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

As of December 31, 2013, Pepco Energy Services had posted net cash collateral of $3 million and letters of credit of less than $1 million. As December 31, 2012, Pepco Energy Services had posted net cash collateral of $25 million and letters of credit of less than $1 million.

Conectiv Energy

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 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.

Conectiv Energy's loss from discontinued operations, net of income taxes, for the years ended December 31, 2013, 2012 and 2011, was zero, zero and $3 million, respectively. Conectiv Energy's other comprehensive income from discontinued operations, net of income taxes, for each of the years ended December 31, 2013, 2012 and 2011, was zero.

Management's Report on Internal Control over Financial Reporting

The management of Potomac Electric Power Company (Pepco) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management of Pepco assessed Pepco's internal control over financial reporting as of December 31, 2013 based on the framework in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment, the management of Pepco concluded that Pepco's internal control over financial reporting was effective as of December 31, 2013.

Report of Independent Registered Public Accounting Firm

To the Shareholder and Board of Directors of
Potomac Electric Power Company

In our opinion, the financial statements of Potomac Electric Power Company (a wholly owned subsidiary of Pepco Holdings, Inc.) listed in the accompanying index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Potomac Electric Power Company at December 31, 2013 and December 31, 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule of Potomac Electric Power Company listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF INCOME

For the Year Ended December 31,	2013	2012	2011
		(millions of dollars)	
Operating Revenue	$2,026	$1,948	$2,078
Operating Expenses			
Purchased energy	750	726	893
Other operation and maintenance	391	403	420
Depreciation and amortization	196	190	171
Other taxes	368	372	382
Total Operating Expenses	1,705	1,691	1,866
Operating Income	321	257	212
Other Income (Expenses)			
Interest expense	(110)	(101)	(94)
Other income	18	18	17
Total Other Expenses	(92)	(83)	(77)
Income Before Income Tax Expense	229	174	135
Income Tax Expense	79	48	36
Net Income	$ 150	$ 126	$ 99

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9	$ 9
Restricted cash equivalents	3	—
Accounts receivable, less allowance for uncollectible accounts of $16 million and $13 million, respectively	345	318
Inventories	67	69
Prepayments of income taxes	9	9
Deferred income tax assets, net	48	9
Income taxes receivable	104	31
Prepaid expenses and other	18	16
Total Current Assets	603	461
OTHER ASSETS		
Regulatory assets	563	487
Prepaid pension expense	332	353
Investment in trust	33	31
Income taxes receivable	36	102
Other	66	59
Total Other Assets	1,030	1,032
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	7,310	6,850
Accumulated depreciation	(2,772)	(2,705)
Net Property, Plant and Equipment	4,538	4,145
TOTAL ASSETS	$ 6,171	$ 5,638

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 151	$ 231
Current portion of long-term debt	175	200
Accounts payable	132	110
Accrued liabilities	90	104
Accounts payable due to associated companies	32	41
Capital lease obligations due within one year	9	8
Taxes accrued	34	58
Interest accrued	20	17
Liabilities and accrued interest related to uncertain tax positions	37	—
Customer deposits	46	48
Other	75	58
Total Current Liabilities	801	875
DEFERRED CREDITS		
Regulatory liabilities	113	141
Deferred income tax liabilities, net	1,412	1,219
Investment tax credits	3	4
Other postretirement benefit obligations	61	66
Liabilities and accrued interest related to uncertain tax positions	10	53
Other	65	66
Total Deferred Credits	1,664	1,549
OTHER LONG-TERM LIABILITIES		
Long-term debt	1,724	1,501
Capital lease obligations	60	70
Total Other Long-Term Liabilities	1,784	1,571
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
EQUITY		
Common stock, $.01 par value, 200,000,000 shares authorized, 100 shares outstanding	—	—
Premium on stock and other capital contributions	930	755
Retained earnings	992	888
Total Equity	1,922	1,643
TOTAL LIABILITIES AND EQUITY	$ 6,171	$ 5,638

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

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS

For the Year Ended December 31,	2013	2012	2011
	(millions of dollars)		
OPERATING ACTIVITIES			
Net Income	$ 150	$ 126	$ 99
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	196	190	171
Deferred income taxes	120	160	73
Investment tax credit amortization	(1)	(1)	(2)
Changes in:			
Accounts receivable	(39)	22	33
Inventories	2	(19)	(6)
Prepaid expenses	(1)	6	1
Regulatory assets and liabilities, net	(99)	(110)	(43)
Accounts payable and accrued liabilities	26	(10)	(27)
Pension contributions	—	(85)	(40)
Prepaid pension expense, excluding contributions	21	21	24
Income tax-related prepayments, receivables and payables	(36)	(69)	73
Interest accrued	2	—	(1)
Other assets and liabilities	(11)	(8)	2
Net Cash From Operating Activities	330	223	357
INVESTING ACTIVITIES			
Investment in property, plant and equipment	(576)	(592)	(521)
Department of Energy capital reimbursement awards received	20	38	48
Changes in restricted cash equivalents	(3)	—	—
Net other investing activities	(5)	4	(7)
Net Cash Used By Investing Activities	(564)	(550)	(480)
FINANCING ACTIVITIES			
Dividends paid to Parent	(46)	(35)	(25)
Capital contributions from Parent	175	50	—
Issuances of long-term debt	400	200	—
Reacquisitions of long-term debt	(200)	(38)	—
Issuances of short-term debt, net	(80)	157	74
Cost of issuances	(7)	(4)	—
Net other financing activities	(8)	(6)	(2)
Net Cash From Financing Activities	234	324	47
Net Decrease in Cash and Cash Equivalents	—	(3)	(76)
Cash and Cash Equivalents at Beginning of Year	9	12	88
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 9	$ 9	$ 12
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid for interest (net of capitalized interest of $5 million, $4 million and $8 million, respectively)	$ 102	$ 97	$ 91
Cash received for income taxes (includes payments from PHI for Federal income taxes)	(28)	(40)	(108)
Non-cash activities:			
Reclassification of property, plant and equipment to regulatory assets	—	50	—
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
STATEMENTS OF EQUITY

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
Balance as of December 31, 2010	100	$ —	$ 705	$ 723	$1,428
Net Income	—	—	—	99	99
Dividends on common stock	—	—	—	(25)	(25)
Balance as of December 31, 2011	100	—	705	797	1,502
Net Income	—	—	—	126	126
Capital contribution from Parent	—	—	50	—	50
Dividends on common stock	—	—	—	(35)	(35)
Balance as of December 31, 2012	100	—	755	888	$1,643
Net Income	—	—	—	150	150
Capital Contribution from Parent	—	—	175	—	175
Dividends on common stock	—	—	—	(46)	(46)
Balance as of December 31, 2013	100	$ —	$ 930	$ 992	$1,922

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

Use of Estimates

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

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

Revenue Recognition

Pepco recognizes revenue upon distribution of electricity to its customers, including unbilled revenue for services rendered, but not yet billed. Pepco's unbilled revenue was $80 million and $81 million as of December 31, 2013 and 2012, respectively, and these amounts are included in Accounts receivable. Pepco calculates unbilled revenue using an output-based methodology. This methodology is based on the supply of electricity intended for distribution to customers. The unbilled revenue process requires management to make assumptions and judgments about input factors such as customer sales mix, temperature, and estimated line losses (estimates of electricity expected to be lost in the process of its transmission and distribution to customers). The assumptions and judgments are inherently uncertain and susceptible to change from period to period, and if actual results differ from projected results, the impact could be material.

Taxes related to the consumption of electricity by its customers, such as fuel, energy, or other similar taxes, are components of Pepco's tariffs and, as such, are billed to customers and recorded in Operating revenue. Accruals for the remittance of these taxes by Pepco are recorded in Other taxes.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco's gross revenues were $318 million, $324 million and $338 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Long-Lived Assets Impairment Evaluation

Pepco evaluates certain long-lived assets to be held and used (for example, equipment and real estate) for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. Examples of such events or changes include a significant decrease in the market price of a long-lived asset or a significant adverse change in the manner in which an asset is being used or its physical condition. A long-lived asset to be held and used is written down to its estimated fair value if the expected future undiscounted cash flow from the asset is less than its carrying value.

For long-lived assets that can be classified as assets to be disposed of by sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value including costs to sell.

Income Taxes

Pepco, as a direct subsidiary of Pepco Holdings, is included in the consolidated federal income tax return of PHI. Federal income taxes are allocated to Pepco based upon the taxable income or loss amounts, determined on a separate return basis.

The financial statements include current and deferred income taxes. Current income taxes represent the amount of tax expected to be reported on Pepco's state income tax returns and the amount of federal income tax allocated from Pepco Holdings.

Deferred income tax assets and liabilities represent the tax effects of temporary differences between the financial statement basis and tax basis of existing assets and liabilities and they are measured using presently enacted tax rates. The portion of Pepco's deferred tax liability applicable to its utility operations that has not been recovered from utility customers represents income taxes recoverable in the future and is included in Regulatory assets on the balance sheets. See Note (6), "Regulatory Matters," for additional information.

Deferred income tax expense generally represents the net change during the reporting period in the net deferred tax liability and deferred recoverable income taxes.

Pepco recognizes interest on underpayments and overpayments of income taxes, interest on uncertain tax positions, and tax-related penalties in income tax expense.

Investment tax credits are being amortized to income over the useful lives of the related property.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, cash invested in money market funds and commercial paper held with original maturities of three months or less. Additionally, deposits in PHI's money pool, which Pepco and certain other PHI subsidiaries use to manage short-term cash management requirements, are considered cash equivalents. Deposits in the money pool are guaranteed by PHI. PHI deposits funds in the money pool to the extent that the pool has insufficient funds to meet the needs of its participants, which may require PHI to borrow funds for deposit from external sources.

Restricted Cash Equivalents

The Restricted cash equivalents included in Current assets consist of (i) cash held as collateral that is restricted from use for general corporate purposes and (ii) cash equivalents that are specifically segregated based on management's intent to use such cash equivalents for a particular purpose. The classification as current conforms to the classification of the related liabilities.

Accounts Receivable and Allowance for Uncollectible Accounts

Pepco's Accounts receivable balance primarily consists of customer accounts receivable arising from the sale of goods and services to customers within its service territory, other accounts receivable, and accrued unbilled revenue. Accrued unbilled revenue represents revenue earned in the current period but not billed to the customer until a future date (usually within one month after the receivable is recorded).

Pepco maintains an allowance for uncollectible accounts and changes in the allowance are recorded as an adjustment to Other operation and maintenance expense in the statements of income. Pepco determines the amount of the allowance based on specific identification of material amounts at risk by customer and maintains a reserve based on its historical collection experience. The adequacy of this allowance is assessed on a quarterly basis by evaluating all known factors such as the aging of the receivables, historical collection experience, the economic and competitive environment and changes in the creditworthiness of its customers. Accounts receivable are written off in the period in which the receivable is deemed uncollectible and collection efforts have been exhausted. Recoveries of Accounts receivable previously written off are recorded when it is probable they will be recovered. Although Pepco believes its allowance is adequate, it cannot anticipate with any certainty the changes in the financial condition of its customers. As a result, Pepco records adjustments to the allowance for uncollectible accounts in the period in which the new information that requires an adjustment to the reserve becomes known.

Inventories

Included in Inventories are transmission and distribution materials and supplies. Pepco utilizes the weighted average cost method of accounting for inventory items. Under this method, an average price is determined for the quantity of units acquired at each price level and is applied to the ending quantity to calculate the total ending inventory balance. Materials and supplies are recorded in Inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Regulatory Assets and Regulatory Liabilities

Pepco is regulated by the Maryland Public Service Commission (MPSC) and the District of Columbia Public Service Commission (DCPSC). The transmission of electricity by Pepco is regulated by the Federal Energy Regulatory Commission (FERC).

Based on the regulatory framework in which it has operated, Pepco has historically applied, and in connection with its transmission and distribution business continues to apply, the Financial Accounting Standards Board (FASB) guidance on regulated operations (Accounting Standards Codification (ASC) 980). The guidance allows regulated entities, in appropriate circumstances, to defer the income statement impact of certain costs that are expected to be recovered in future rates through the establishment of regulatory assets and defer certain revenues that are expected to be refunded to customers through the establishment of regulatory liabilities. Management's assessment of the probability of recovery of regulatory assets requires judgment and interpretation of laws, regulatory commission orders and other factors. If management subsequently determines, based on changes in facts or circumstances, that a regulatory asset is not probable of recovery, the regulatory asset would be eliminated through a charge to earnings.

Effective June 2007, the MPSC approved a bill stabilization adjustment (BSA) mechanism for retail customers. Effective November 2009, the DCPSC approved a BSA for retail customers. For customers to whom the BSA applies, Pepco recognizes distribution revenue based on an approved distribution charge per customer. From a revenue recognition standpoint, the BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during that period. Pursuant to this mechanism, Pepco recognizes either (i) a positive adjustment equal to the amount by which revenue from Maryland and the 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 (a Revenue Decoupling Adjustment). A net positive Revenue Decoupling Adjustment is recorded as a regulatory asset and a net negative Revenue Decoupling Adjustment is recorded as a regulatory liability.

Investment in Trust

Represents assets held in a trust for the benefit of participants in the Pepco Owned Life Insurance plan.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The carrying value of Property, plant and equipment is evaluated for impairment whenever circumstances indicate the carrying value of those assets may not be recoverable. Upon retirement, the cost of regulated property, net of salvage, is charged to Accumulated depreciation. For additional information regarding the treatment of asset removal obligations, see the "Asset Removal Costs" section included in this Note.

The annual provision for depreciation on electric property, plant and equipment is computed on a straight-line basis using composite rates by classes of depreciable property. Accumulated depreciation is charged with the cost of depreciable property retired, less salvage and other recoveries. Non-operating and other property is generally depreciated on a straight-line basis over the useful lives of the assets. The system-wide composite annual depreciation rates for the years ended December 31, 2013, 2012 and 2011 for Pepco's property were approximately 2.2%, 2.5% and 2.6%, respectively.

In 2010, Pepco was awarded $149 million from the U.S. Department of Energy (DOE) to fund a portion of the costs incurred for the implementation of an advanced metering infrastructure system, direct load control, distribution automation and communications infrastructure in its Maryland and District of Columbia service territories. Pepco has elected to recognize the award proceeds as a reduction in the carrying value of the assets acquired rather than grant income over the service period.

Capitalized Interest and Allowance for Funds Used During Construction

In accordance with FASB guidance on regulated operations (ASC 980), utilities can capitalize the capital costs of financing the construction of plant and equipment as Allowance for Funds Used During Construction (AFUDC). This results in the debt portion of AFUDC being recorded as a reduction of Interest expense and the equity portion of AFUDC being recorded as an increase to Other income in the accompanying statements of income.

Pepco recorded AFUDC for borrowed funds of $5 million, $4 million and $8 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Pepco recorded amounts for the equity component of AFUDC of $9 million, $8 million and $12 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Leasing Activities

Pepco's lease transactions include office space, equipment, software and vehicles. In accordance with FASB guidance on leases (ASC 840), these leases are classified as either operating leases or capital leases.

Operating Leases

An operating lease in which Pepco is the lessee generally results in a level income statement charge over the term of the lease, reflecting the rental payments required by the lease agreement. If rental payments are not made on a straight-line basis, Pepco's policy is to recognize rent expense on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed.

Capital Leases

For ratemaking purposes, capital leases in which Pepco is the lessee are treated as operating leases; therefore, in accordance with FASB guidance on regulated operations (ASC 980), the amortization of the leased asset is based on the recovery of rental payments through customer rates. Investments in equipment under capital leases are stated at cost, less accumulated depreciation. Depreciation is recorded on a straight-line basis over the equipment's estimated useful life.

Amortization of Debt Issuance and Reacquisition Costs

Pepco defers and amortizes debt issuance costs and long-term debt premiums and discounts over the lives of the respective debt issuances. When refinancing or redeeming existing debt, any unamortized premiums, discounts and debt issuance costs, as well as debt redemption costs, are classified as Regulatory assets and are amortized generally over the life of the new issue.

Asset Removal Costs

In accordance with FASB guidance, asset removal costs are recorded as regulatory liabilities. At December 31, 2013 and 2012, $102 million and $122 million, respectively, of asset removal costs are included in Regulatory liabilities in the accompanying balance sheets.

Pension and Postretirement Benefit Plans

Pepco Holdings sponsors the PHI Retirement Plan, a non-contributory, defined benefit pension plan that covers substantially all employees of Pepco and certain employees of other Pepco Holdings subsidiaries. Pepco Holdings also provides supplemental retirement benefits to certain eligible executives and key employees through nonqualified retirement plans and provides certain postretirement health care and life insurance benefits for eligible retired employees.

The PHI Retirement Plan is accounted for in accordance with FASB guidance on retirement benefits (ASC 715).

Dividend Restrictions

All of Pepco's shares of outstanding common stock are held by PHI, its parent company. In addition to its future financial performance, the ability of Pepco to pay dividends to its parent company is subject to limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of future preferred stock, if any, and existing and future mortgage bonds and other long-term debt issued by Pepco and any other restrictions imposed in connection with the incurrence of liabilities. Pepco has no shares of preferred stock outstanding. Pepco had approximately $992 million and $888 million of retained earnings available for payment of common stock dividends at December 31, 2013 and 2012, respectively. These amounts represent the total retained earnings balances at those dates.

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 individually or in the aggregate to either the current period or prior period financial results:

Income Tax Adjustments

During 2013, Pepco recorded certain adjustments to correct prior period errors related to income taxes. These adjustments resulted from the completion of additional analysis of deferred tax balances and resulted in an increase in Income tax expense of $4 million for the year ended December 31, 2013.

During 2011, Pepco recorded an adjustment to correct certain income tax errors related to prior periods associated with the interest on uncertain tax positions. The adjustment resulted in an increase in Income tax expense of $1 million for the year ended December 31, 2011.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

None.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, Pepco will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. Pepco will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between Pepco and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements are effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. Pepco does not expect this new guidance to have a material impact on its financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with Pepco’s March 31, 2014 financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. Pepco does not expect this new guidance to have a material impact on its financial statements.

(5) SEGMENT INFORMATION

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

(6) REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

The components of Pepco's regulatory asset and liability balances at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Regulatory Assets		
Smart Grid costs (a)	$ 168	$ 159
Recoverable income taxes	107	75
Demand-side management costs (a)	98	45
Incremental storm restoration costs (a)	37	44
MAPP abandonment costs (a)	37	50
Recoverable workers' compensation and long-term disability costs	26	31
Deferred debt extinguishment costs (a)	25	28
Deferred energy supply costs	6	4
Other	59	51
Total Regulatory Assets	$ 563	$ 487
Regulatory Liabilities		
Asset removal costs	$ 102	$ 122
Other	11	19
Total Regulatory Liabilities	$ 113	$ 141

(a) A return is generally earned on these deferrals.

A description for each category of regulatory assets and regulatory liabilities follows:

Smart Grid Costs: Represents advanced metering infrastructure (AMI) costs associated with the installation of smart meters and the early retirement of existing meters throughout Pepco's service territory that are recoverable from customers.

Recoverable Income Taxes: Represents amounts recoverable from Pepco's customers for tax benefits applicable to utility operations that were previously recognized in income tax expense before the company was ordered to account for the tax benefits as deferred income taxes. As the temporary differences between the financial statement basis and tax basis of assets reverse, the deferred recoverable balances are reversed.

Demand-Side Management Costs: Represents recoverable costs associated with customer energy efficiency and conservation programs in Pepco's Maryland jurisdiction.

Incremental Storm Restoration Costs: Represents total incremental storm restoration costs incurred for repair work due to major storm events in 2012 and 2011, including Hurricane Sandy, the June 2012 derecho, Hurricane Irene, and the 2011 severe winter storm, that are recoverable from customers in the Maryland jurisdiction. Pepco's costs related to Hurricane Sandy, the June 2012 derecho, Hurricane Irene and the 2011 severe winter storm are being amortized and recovered in rates, each over a five-year period.

MAPP Abandonment Costs: Represents the probable recovery of abandoned costs prudently incurred in connection with the Mid-Atlantic Power Pathway (MAPP) project which was terminated on August 24, 2012. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. The regulatory asset will be reduced as the result of sale or alternative use of these assets. As of December 31, 2013, these assets were earning a return of 12.8%. For additional information, see "MAPP Project" discussion below.

Recoverable Workers' Compensation and Long-Term Disability Costs: Represents accrued workers' compensation and long-term disability costs for Pepco, which are recoverable from customers when actual claims are paid to employees.

Deferred Debt Extinguishment Costs: Represents the costs of debt extinguishment associated with issuances of debt for which recovery through regulated utility rates is considered probable, and if approved, will be amortized to interest expense during the authorized rate recovery period.

Deferred Energy Supply Costs: The regulatory asset represents primarily deferred costs associated with a net under-recovery of Default Electricity Supply costs incurred by Pepco that are probable of recovery in rates.

Other: Represents miscellaneous regulatory assets that generally are being amortized over 1 to 20 years.

Asset Removal Costs: The depreciation rates for Pepco include a component for removal costs, as approved by the relevant federal and state regulatory commissions. Accordingly, Pepco has recorded regulatory liabilities for its estimate of the difference between incurred removal costs and the amount of removal costs recovered through depreciation rates.

Other: Includes miscellaneous regulatory liabilities.

Rate Proceedings

Bill Stabilization Adjustment

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

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

District of Columbia

On March 8, 2013, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by approximately $44.8 million (as adjusted by Pepco on December 3, 2013), based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. Evidentiary hearings were held in November 2013 and a final DCPSC decision is expected in the first quarter of 2014.

Maryland

In December 2011, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently reduced by Pepco to $66.2 million), based on a requested ROE of 10.75%. In July 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. The order also reduced Pepco's depreciation rates, which lowered annual depreciation and amortization expenses by an estimated $27.3 million. The lower depreciation rates resulted from, among other things, the rebalancing of excess reserves for estimated future removal costs identified in a depreciation study conducted as part of the rate case filing. The identified excess reserves for estimated future removal costs, reported as Regulatory liabilities, were reclassified to Accumulated depreciation among various plant accounts. Among other things, the order additionally authorized Pepco to recover the actual cost of AMI meters installed during the 2011 test year and states that cost recovery for AMI deployment will be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. The Maryland OPC has sought rehearing on the portion of the order allowing Pepco to recover the costs of AMI meters installed during the test year; that motion remains pending.

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

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

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

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

On December 4, 2013, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $43.3 million, based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. A decision is expected in the third quarter of 2014.

Federal Energy Regulatory Commission

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc., filed a joint complaint with the Federal Energy Regulatory Commission (FERC) against Pepco and its affiliates Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that Pepco and its utility affiliates provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for Pepco and its utility affiliates is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. Pepco believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, Pepco filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. Pepco cannot predict when a final FERC decision in this proceeding will be issued.

MPSC New Generation Contract Requirement

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

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

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

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

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit. These appeals remain pending.

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

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

Resiliency Task Forces

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

In August 2012, the District of Columbia mayor issued an Executive Order establishing the Mayor's Power Line Undergrounding Task Force (the DC Undergrounding Task Force). The stated purpose of the DC Undergrounding Task Force was to pool the collective resources available in the District of Columbia to produce an analysis of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead distribution facilities in the District of Columbia. These resources included legislative bodies, regulators, utility personnel, experts and other parties who could contribute in a meaningful way to the DC Undergrounding Task Force. On May 13, 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan of the DC Undergrounding Task Force to underground 60 of the District of Columbia's most outage-prone power lines, which lines would be owned and maintained by Pepco. The legislation providing for implementation of the report's recommendations contemplates that: (i) Pepco would fund approximately

$500 million of the $1 billion estimated cost to complete this project, recovering those costs through surcharges on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the undergrounding project cost would be financed by the District of Columbia's issuance of securitized bonds, which bonds would be repaid through surcharges on the electric bills of Pepco District of Columbia customers (Pepco would not earn a return on or of the cost of the assets funded with the proceeds received from the issuance of the securitized bonds, but ownership and responsibility for the operation and maintenance of such assets would be transferred to Pepco for a nominal amount); and (iii) the remaining amount would be funded through the District of Columbia Department of Transportation's existing capital projects program. This legislation was approved in the Council of the District of Columbia on February 4, 2014 and is awaiting the signature of the Mayor of the District of Columbia. Once signed by the Mayor and transmitted to Congress, the legislation will undergo a 30-day Congressional review period before becoming law, which is expected to occur in the second quarter of 2014. The final step would be DCPSC approval of the underground project plan and financing orders required by the legislation to establish the customer surcharges contemplated by the legislation, a decision on which is expected during the fourth quarter of 2014.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. Pepco had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, Pepco submitted a filing to FERC seeking recovery of approximately $50 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

On December 18, 2013, Pepco submitted a settlement agreement to FERC, which provides for recovery of Pepco's abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. Pepco cannot predict the timing or results of a final FERC decision in this proceeding.

As of December 31, 2013, Pepco had a regulatory asset related to the MAPP abandoned costs of approximately $37 million, representing the original filing amount of approximately $50 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; (ii) $4 million of materials transferred to inventories for use on other projects; and (iii) $8 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration.

(7) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	Original Cost	Accumulated Depreciation	Net Book Value
		(millions of dollars)	
At December 31, 2013			
Distribution	$5,287	$ 2,027	$ 3,260
Transmission	1,223	444	779
Construction work in progress	312	—	312
Non-operating and other property	488	301	187
Total	$7,310	$ 2,772	$ 4,538
At December 31, 2012			
Distribution	$4,949	$ 1,995	$ 2,954
Transmission	1,166	419	747
Construction work in progress	303	—	303
Non-operating and other property	432	291	141
Total	$6,850	$ 2,705	$ 4,145

The non-operating and other property amounts include balances for general plant, distribution plant and transmission plant held for future use, intangible plant and non-utility property. Utility plant is generally subject to a first mortgage lien.

Capital Leases

Pepco leases its consolidated control center, which is an integrated energy management center used by Pepco to centrally control the operation of its transmission and distribution systems. This lease is accounted for as a capital lease and was initially recorded at the present value of future lease payments. The lease requires semi-annual payments of approximately $8 million over a 25-year period that began in December 1994, and provides for transfer of ownership of the system to Pepco for $1 at the end of the lease term. Under FASB guidance on regulated operations, the amortization of leased assets is modified so that the total interest expense charged on the obligation and amortization expense of the leased asset is equal to the rental expense allowed for rate-making purposes. The amortization expense is included within Depreciation and amortization in the statements of income. This lease is treated as an operating lease for rate-making purposes.

Capital lease assets recorded within Property, plant and equipment at December 31, 2013 and 2012 are comprised of the following:

	Original Cost	Accumulated Amortization (millions of dollars)	Net Book Value
At December 31, 2013			
Transmission	$ 76	$ 41	$ 35
Distribution	76	42	34
Other	3	3	—
Total	$ 155	$ 86	$ 69
At December 31, 2012			
Transmission	$ 76	$ 37	$ 39
Distribution	76	37	39
Other	3	3	—
Total	$ 155	$ 77	$ 78

The approximate annual commitments under capital leases are $15 million for each year 2014 through 2018, and $16 million thereafter.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

Pepco accounts for its participation in its parent's single-employer plans, Pepco Holding's non-contributory retirement plan (the PHI Retirement Plan) and the Pepco Holdings, Inc. Welfare Plan for Retirees (the PHI OPEB Plan), as participation in multiemployer plans. For 2013, 2012 and 2011, Pepco was responsible for $34 million, $39 million and $43 million, respectively, of the pension and other postretirement net periodic benefit cost incurred by PHI. Pepco made a discretionary, tax-deductible contribution of zero, $85 million and $40 million to the PHI Retirement Plan for the years ended December 31, 2013, 2012 and 2011, respectively. In addition, Pepco made contributions of $6 million, $5 million and $7 million, respectively, to the PHI OPEB Plan for the years ended December 31, 2013, 2012 and 2011. At December 31, 2013 and 2012, Pepco's Prepaid pension expense of $332 million and $353 million, respectively, and Other postretirement benefit obligations of $61 million and $66 million, respectively, effectively represent assets and benefit obligations resulting from Pepco's participation in the Pepco Holdings benefit plans.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and the retiree life insurance benefits, and were effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $4 million reduction in Pepco's net periodic benefit cost for other postretirement benefits in 2013. Approximately 38% of net periodic other postretirement benefit costs were capitalized in 2013.

(9) DEBT

Long-Term Debt

The components of long-term debt are shown in the table below:

Type of Debt	Interest Rate	Maturity	2013	2012
			(millions of dollars)	
First Mortgage Bonds	4.95%(a)(b)	2013	$ —	$ 200
	4.65%(a)(b)	2014	175	175
	3.05%	2022	200	200
	6.20%(c)(d)	2022	110	110
	5.75%(a)(b)	2034	100	100
	5.40%(a)(b)	2035	175	175
	6.50%(a)(c)	2037	500	500
	7.90%	2038	250	250
	4.15%	2043	250	—
	4.95%	2043	150	—
Total long-term debt			1,910	1,710
Net unamortized discount			(11)	(9)
Current portion of long-term debt			(175)	(200)
Total net long-term debt			$1,724	$1,501

(a) Represents a series of Collateral First Mortgage Bonds securing a series of senior notes issued by Pepco.
(b) Represents a series of Collateral First Mortgage Bonds (as defined herein) which must be cancelled and released as security for Pepco's obligations under the corresponding series of senior notes or tax-exempt bonds, at such time as Pepco does not have any first mortgage bonds outstanding (other than its Collateral First Mortgage Bonds).
(c) Represents a series of Collateral First Mortgage Bonds which must be cancelled and released as security for Pepco's obligations under the corresponding series of senior notes or tax-exempt bonds, at such time as Pepco does not have any first mortgage bonds outstanding (other than its Collateral First Mortgage Bonds), except that Pepco may not permit such release of collateral unless Pepco substitutes comparable obligations for such collateral.
(d) Represents a series of Collateral First Mortgage Bonds securing a series of senior notes issued by Pepco, which in turn secures a series of tax-exempt bonds issued for the benefit of Pepco.

The outstanding first mortgage bonds are issued under a mortgage and deed of trust and are secured by a first lien on substantially all of Pepco's property, plant and equipment, except for certain property excluded from the lien of the mortgage.

Maturities of Pepco's long-term debt outstanding at December 31, 2013, are $175 million in 2014, zero in 2015 through 2018 and $1,735 million thereafter.

Pepco's long-term debt is subject to certain covenants. As of December 31, 2013, Pepco is in compliance with all such covenants.

The table above does not separately identify $1,060 million in aggregate principal amount of senior notes issued by Pepco and $110 million in aggregate principal amount of tax-exempt bonds issued for the benefit of Pepco. These senior notes are secured by a like amount of first mortgage bonds (Collateral First Mortgage Bonds) of Pepco. In addition, these tax-exempt bonds are secured by a like amount of Collateral First Mortgage Bonds issued by Pepco. The principal terms of each such series of senior notes, or Pepco's obligations in respect of each such series of tax-exempt bonds, are identical to the same terms of the corresponding series of Collateral First Mortgage Bonds. Payments of principal and interest made on a series of such senior notes, or the satisfaction of Pepco's obligations in respect of a series of such tax-exempt bonds, satisfy the corresponding obligations on the related series of Collateral First Mortgage Bonds. For these reasons, each such series of Collateral First Mortgage Bonds and the corresponding senior notes and/or tax-exempt bonds together effectively represent a single financial obligation and are not identified in the table above separately.

Bond Issuances

During 2013, Pepco issued $250 million of 4.15% first mortgage bonds due March 15, 2043 and $150 million of 4.95% first mortgage bonds due November 15, 2043. Net proceeds from the issuance of the 4.15% bonds were used to repay Pepco's outstanding commercial paper and for general corporate purposes. The net proceeds from the 4.95% bonds were used to repay outstanding commercial paper, including commercial paper issued to repay in full at maturity $200 million of 4.95% senior notes due November 15, 2013, plus accrued but unpaid interest thereon. The senior notes were secured by a like principal amount of first mortgage bonds, which under the mortgage and deed of trust were deemed to be satisfied with the repayment of the senior notes.

Bond Redemptions

During 2013, Pepco repaid at maturity $200 million of its 4.95% senior notes, which were secured by a like principal amount of its first mortgage bonds.

Short-Term Debt

Pepco has traditionally used a number of sources to fulfill short-term funding needs, such as commercial paper, short-term notes, and bank lines of credit. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements.

The components of Pepco's short-term debt at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Commercial paper	$ 151	$ 231
Total	$ 151	$ 231

Commercial Paper

Pepco maintains an ongoing commercial paper program to address its short-term liquidity needs. As of December 31, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

Pepco had $151 million and $231 million of commercial paper outstanding at December 31, 2013 and 2012, respectively. The weighted average interest rates for commercial paper issued by Pepco during 2013 and 2012 were 0.34% and 0.43%, respectively. The weighted average maturity of all commercial paper issued by Pepco during each of 2013 and 2012 was five days.

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On August 1, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained the same.

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

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

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of December 31, 2013.

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

As of December 31, 2013 and 2012, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $332 million and $477 million, respectively. Pepco's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by DPL and ACE and the portion of the total capacity being used by PHI.

(10) INCOME TAXES

Pepco, as a direct subsidiary of PHI, is included in the consolidated federal income tax return of PHI. Federal income taxes are allocated to Pepco pursuant to a written tax sharing agreement that was approved by the Securities and Exchange Commission in connection with the establishment of PHI as a holding company. Under this tax sharing agreement, PHI's consolidated federal income tax liability is allocated based upon PHI's and its subsidiaries' separate taxable income or loss.

The provision for income taxes, reconciliation of income tax expense, and components of deferred income tax liabilities (assets) are shown below.

Provision for Income Taxes

	For the Year Ended December 31, 2013	2012	2011
		(millions of dollars)	
Current Tax Benefit			
Federal	$ (39)	$ (84)	$ (19)
State and local	(1)	(27)	(16)
Total Current Tax Benefit	(40)	(111)	(35)
Deferred Tax Expense (Benefit)			
Federal	96	127	54
State and local	24	33	19
Investment tax credit amortization	(1)	(1)	(2)
Total Deferred Tax Expense	119	159	71
Total Income Tax Expense	$ 79	$ 48	$ 36

Reconciliation of Income Tax Expense

	For the Year Ended December 31, 2013		2012		2011	
			(millions of dollars)			
Income tax at Federal statutory rate	$ 80	35.0%	$ 61	35.0%	$47	35.0 %
Increases (decreases) resulting from:						
State income taxes, net of Federal effect	13	5.7%	10	5.7%	8	5.5%
Asset removal costs	(14)	(6.1)%	(11)	(6.3)%	(7)	(5.0)%
Change in estimates and interest related to uncertain and effectively settled tax positions	(3)	(1.3)%	(11)	(6.3)%	(9)	(6.6)%
Other, net	3	1.2%	(1)	(0.5)%	(3)	(2.2)%
Income Tax Expense	$ 79	34.5%	$ 48	27.6%	$36	26.7%

Year ended December 31, 2013

Pepco's effective income tax rate for the year ended December 31, 2013 of 34.5% reflects income tax benefits totaling $3 million related to uncertain and effectively settled tax positions.

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

Year ended December 31, 2012

Pepco's effective income tax rate for the year ended December 31, 2012 of 27.6% primarily reflects tax benefits related to asset removal costs and changes in estimates and interest related to uncertain and effectively settled tax positions.

During 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.

The effective income tax rate also reflects an increase in deductible asset removal costs for Pepco in 2012 related to a higher level of asset retirements.

Year ended December 31, 2011

Pepco's effective income tax rate for the year ended December 31, 2011 of 26.7% includes income tax benefits totaling $9 million related to uncertain and effectively settled tax positions.

During 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, Pepco recorded a tax benefit of $5 million (after-tax) in the second quarter of 2011.

During the third quarter of 2011, Pepco recalculated interest on its uncertain tax positions for open tax years based on different assumptions related to the application of its deposit made with the IRS in 2006. This resulted in an additional tax expense of $1 million (after-tax).

During 2011, Pepco decided to adopt the safe harbor tax accounting method for certain repairs pursuant to IRS guidance. As a result, Pepco reversed $23 million of previously recorded liabilities on uncertain tax positions and reversed the associated $1 million of accrued interest.

In May 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.

Components of Deferred Income Tax Liabilities (Assets)

	At December 31, 2013	At December 31, 2012
	(millions of dollars)	
Deferred Tax Liabilities (Assets)		
Depreciation and other basis differences related to plant and equipment	$1,240	$1,105
Pension and other postretirement benefits	105	111
Deferred taxes on amounts to be collected through future rates	43	28
Federal and state net operating losses	(169)	(174)
Other	145	140
Total Deferred Tax Liabilities, net	1,364	1,210
Deferred tax assets included in Current Assets	48	9
Total Deferred Tax Liabilities, net non-current	$1,412	$1,219

The net deferred tax liability represents the tax effect, at presently enacted tax rates, of temporary differences between the financial statement basis and tax basis of assets and liabilities. The portion of the net deferred tax liability applicable to Pepco's operations, which has not been reflected in current service rates, represents income taxes recoverable through future rates, net, and is recorded as a regulatory asset on the balance sheet. No valuation allowance for deferred tax assets was required or recorded at December 31, 2013 and 2012. Federal and state net operating losses generally expire over 20 years from 2029 to 2032.

The Tax Reform Act of 1986 repealed the investment tax credit for property placed in service after December 31, 1985, except for certain transition property. Investment tax credits previously earned on Pepco's property continue to be amortized to income over the useful lives of the related property.

Reconciliation of Beginning and Ending Balances of Unrecognized Tax Benefits

	2013	2012	2011
		(millions of dollars)	
Balance as of January 1	$ 91	$ 173	$190
Tax positions related to current year:			
Additions	1	—	—
Reductions	—	—	—
Tax positions related to prior years:			
Additions	12	60	12
Reductions	(3)	(142)(a)	(26)
Settlements	—	—	(3)
Balance as of December 31	$101	$ 91	$173

(a) These reductions of unrecognized tax benefits in 2012 primarily relate to a resolution reached with the IRS for determining deductible mixed service costs for additions to property, plant and equipment.

Unrecognized Benefits That, If Recognized, Would Affect the Effective Tax Rate

Unrecognized tax benefits are related to tax positions that have been taken or are expected to be taken in tax returns that are not recognized in the financial statements because management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or has concluded that it is not more likely than not that the tax position will be ultimately sustained. For the majority of these tax positions, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. At December 31, 2013, Pepco had less than $1 million of unrecognized tax benefits that, if recognized, would lower the effective tax rate.

Interest and Penalties

Pepco recognizes interest and penalties relating to its uncertain tax positions as an element of income tax expense. For the years ended December 31, 2013, 2012 and 2011, Pepco recognized $5 million of pre-tax interest income ($3 million after-tax), $18 million of pre-tax interest income ($11 million after-tax), and $8 million of pre-tax interest income ($5 million after-tax), respectively, as a component of income tax expense. As of December 31, 2013, 2012 and 2011, Pepco had accrued interest receivable of $9 million, accrued interest receivable of $5 million and accrued interest payable of $6 million, respectively, related to effectively settled and uncertain tax positions.

Possible Changes to Unrecognized Tax Benefits

It is reasonably possible that the amount of the unrecognized tax benefit with respect to some of Pepco's uncertain tax positions will significantly increase or decrease within the next 12 months. PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues of Pepco for open tax years 2001 through 2011. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014, which could significantly impact the balances of unrecognized tax benefits and the related interest accruals of Pepco. At this time, it is estimated that there will be a $65 million to $85 million decrease in unrecognized tax benefits within the next 12 months.

Tax Years Open to Examination

Pepco, as a direct subsidiary of PHI, is included on PHI's consolidated Federal income tax return. Pepco's federal income tax liabilities for all years through 2002 have been determined, subject to adjustment to the extent of any net operating loss or other loss or credit carrybacks from subsequent years. The open tax years for the significant states where Pepco files state income tax returns (District of Columbia and Maryland) are the same as for the Federal returns. As a result of the final determination of these years, Pepco filed amended state returns requesting $20 million in refunds which are subject to review by the various states. To date, Pepco has received $4 million in refunds and legislation has been enacted in the District of Columbia (subject to a 30-day Congressional review period before becoming law) which will allow for the recovery of the remaining $16 million in refunds.

Final IRS Regulations on Repair of Tangible Property

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

Other Taxes

Taxes other than income taxes for each year are shown below. These amounts are recoverable through rates.

	2013	2012	2011
	(millions of dollars)		
Gross Receipts/Delivery	$108	$106	$109
Property	45	46	44
County Fuel and Energy	153	160	170
Environmental, Use and Other	62	60	59
Total	$368	$372	$382

(11) 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 December 31, 2013 and 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Pepco's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

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

	Fair Value Measurements at December 31, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Executive deferred compensation plan assets				
Money market funds	$ 15	$ 15	$ —	$ —
Life insurance contracts	56	—	38	18
	$ 71	$ 15	$ 38	$ 18
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 9	$ —	$ 9	$ —
	$ 9	$ —	$ 9	$ —

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

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

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

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

Executive deferred compensation plan assets and liabilities categorized as level 2 consist of life insurance policies and certain employment agreement obligations. The life insurance policies are categorized as level 2 assets because they are valued based on the assets underlying the policies, which consist of short-term cash equivalents and fixed income securities that are priced using observable market data and can be liquidated for the value of the underlying assets as of December 31, 2013. The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

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

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

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

Reconciliations of the beginning and ending balances of Pepco’s fair value measurements using significant unobservable inputs (Level 3) for the years ended December 31, 2013 and 2012 are shown below.

	Life Insurance Contracts	
	Year Ended December 31,	
	2013	**2012**
	(millions of dollars)	
Balance as of January 1	$ 18	$ 17
Total gains (losses) (realized and unrealized):		
Included in income	4	4
Included in accumulated other comprehensive loss	—	—
Purchases	—	—
Issuances	(3)	(3)
Settlements	(1)	—
Transfers in (out) of level 3	—	—
Balance as of December 31	$ 18	$ 18

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:

	Year Ended December 31, 2013	Year Ended December 31, 2012
	(millions of dollars)	
Total gains included in income for the period	$ 4	$ 4
Change in unrealized gains relating to assets still held at reporting date	$ 4	$ 4

Other Financial Instruments

The estimated fair values of Pepco's Long-term debt instruments that are measured at amortized cost in Pepco's financial statements and the associated level of the estimates within the fair value hierarchy as of December 31, 2013 and 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. Pepco's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

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

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

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

	Fair Value Measurements at December 31, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)(a)	Significant Other Observable Inputs (Level 2)(a)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (b)	$2,160	$ —	$ 2,160	$ —
	$2,160	$ —	$ 2,160	$ —

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

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

(12) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, Pepco is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. Pepco is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, Pepco's contracts with its vendors generally require the vendors to name Pepco as an additional insured for the amount at least equal to Pepco's self-insured retention. Further, Pepco's contracts with its vendors require the vendors to indemnify Pepco for various acts and activities that may give rise to claims against Pepco. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on Pepco's financial condition, results of operations or cash flows. At December 31, 2013, Pepco had loss contingency liabilities for general litigation totaling approximately $19 million (including amounts related to the matter specifically described below) and the portion of these loss contingency liabilities in excess of the self-insured retention amount was substantially offset by insurance receivables.

Substation Injury Claim

In May 2013, a contract worker erecting a scaffold at a Pepco substation came into contact with an energized station service feeder and suffered serious injuries. In August 2013, the individual filed suit against Pepco in the Circuit Court for Montgomery County, Maryland, seeking damages for medical expenses, loss of future earning capacity, pain and suffering and the cost of a life care plan aggregating to a maximum claim of approximately $28.1 million. Discovery is ongoing in the case and, if a settlement cannot be reached with respect to this matter, a trial is expected to begin in October 2014. Pepco has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident, including the policies of the contractor performing the scaffold work (which name Pepco as an additional insured), will offset substantially all of Pepco's costs associated with the resolution of this matter, including Pepco's self-insured retention amount. At December 31, 2013, Pepco has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of December 31, 2013. Pepco has also concluded as of December 31, 2013 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable offsetting substantially all of the related loss contingency liability.

Environmental Matters

Pepco is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of Pepco, environmental clean-up costs incurred by Pepco generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of Pepco described below at December 31, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
	(millions of dollars)		
Balance as of January 1	$ 14	$ 3	$ 17
Accruals	5	—	5
Payments	(1)	—	(1)
Balance as of December 31	18	3	21
Less amounts in Other Current Liabilities	2	—	2
Amounts in Other Deferred Credits	$ 16	$ 3	$ 19

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 in November 2009, EPA placed the Peck Iron and Metal site on the National Priorities List. The National Priorities List, among other things, serves as a guide to EPA in determining which sites warrant further investigation to assess the nature and extent of the human health and environmental risks associated with a site. In September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Ward Transformer Site

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

Benning Road Site

In September 2010, PHI received a letter from EPA identifying the Benning Road location, consisting of a generation facility operated by Pepco Energy Services until the facility was deactivated in June 2012, and a transmission and distribution facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The letter stated that the principal contaminants of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the District of Columbia Department of the Environment (DDOE), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DDOE's selection of a remedial action for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DDOE will look to the companies to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

In December 2012, DDOE approved the RI/FS work plan. RI/FS field work commenced in January 2013 and is still in progress. In October 2013, Pepco and Pepco Energy Services submitted a work plan addendum for approval by DDOE identifying the location of groundwater monitoring wells to be installed at the site and sampled as the last phase of the field work. The work plan addendum has been revised in response to comments from DDOE, and it is expected that the addendum will be approved and the next phase of field work will commence before the end of the first quarter of 2014. Once all of the field work has been completed, Pepco and Pepco Energy Services will prepare RI/FS reports for review and approval by DDOE after solicitation and consideration of public comment. The next status report to the court is due on May 24, 2014.

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

Potomac River Mineral Oil Release

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

Beginning in March 2011, DDOE issued a series of compliance directives requiring Pepco to prepare an incident report, provide certain records, and prepare and implement plans for sampling surface water and river sediments and assessing ecological risks and natural resources damages. Pepco completed field sampling during the fourth quarter of 2011 and submitted sampling results to DDOE during the second quarter of 2012. Pepco is continuing discussions with DDOE regarding the need for any further response actions but expects that additional monitoring of shoreline sediments may be required.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened enforcement action, including civil penalties, for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. Pepco and DDOE have reached an agreement in principle that would consist of a combination of a civil penalty and Supplemental Environmental Projects (SEPs) with a total cost to Pepco of approximately $1 million. DDOE has endorsed Pepco's proposed SEP involving the installation and operation of a trash collection system at a stormwater outfall that drains to the Anacostia River. DDOE and Pepco are completing negotiations on the text of a consent decree to document the settlement of DDOE's enforcement action and a written statement of work describing the details of the trash collection system SEP. It is expected that the consent decree will be filed with the District of Columbia Superior Court by the end of the first quarter of 2014, with a request that the court approve the consent decree following a period of at least 30 days for public comment. Discussions will proceed separately with DDOE and the federal resource trustees regarding the settlement of a natural resource damage (NRD) claim under federal law. Based on discussions to date, Pepco does not believe that the resolution of DDOE's enforcement action or the federal NRD claim will have a material adverse effect on its financial condition, results of operations or cash flows.

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

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

Metal Bank Site

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

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

Brandywine Fly Ash Disposal Site

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

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

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

Watts Branch Insulating Fluid Release

On September 13, 2013, a Washington Metropolitan Area Transit Authority contractor damaged a Pepco underground transmission feeder while drilling a grout column for a subway tunnel under a city street. The damage caused the release of approximately 11,250 gallons of insulating fluid, a small amount of which reached the Watts Branch, a tributary of the Anacostia River. The U.S. Coast Guard (USCG) issued a notice of federal interest for an oil pollution incident, informing Pepco of its responsibility under the Oil Pollution Act of 1990 for removal costs and damages from the release. In addition, on September 25, 2013, DDOE issued a compliance directive that required Pepco to prepare an incident investigation report describing the events leading up to the release. The compliance directive also required Pepco to prepare work plans for sampling the insulating fluid and for developing and implementing a biological assessment and physical habitat quality assessment to be conducted in Watts Branch. Pepco prepared the incident investigation report and work plans and submitted them to DDOE and USCG. In December 2013, Pepco received and responded to an EPA information request regarding this incident.

Pepco believes that a loss in this matter is probable; however, the costs to resolve this matter are expected to be less than $1 million and are being expensed as incurred. Pepco further believes that the costs incurred will be recoverable from the party or parties responsible for the release. On December 4, 2013, the USCG delivered a Notice of Violation with respect to this matter, which imposed a $3,000 penalty on Pepco, which Pepco has paid.

District of Columbia Tax Legislation

In 2011, the Council of the District of Columbia approved the Fiscal Year 2012 Budget Support Act of 2011, which requires that corporate taxpayers in the District of Columbia calculate taxable income allocable or apportioned to the District of Columbia by reference to the income and apportionment factors applicable to commonly controlled entities organized within the United States that are engaged in a unitary business. In the aggregate, this new tax reporting method reduced pre-tax earnings for the year ended December 31, 2011 by less than $1 million. During 2012, the District of Columbia Office of Tax and Revenue adopted regulations to implement this reporting method. PHI has analyzed these regulations and determined that the regulations did not impact PHI’s results of operations for the years ended December 31, 2013 and 2012.

Contractual Obligations

Power Purchase Contracts

As of December 31, 2013, Pepco had no contractual obligations under non-derivative power purchase contracts.

Lease Commitments

Rental expense for operating leases was $7 million, $6 million and $4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Total future minimum operating lease payments for Pepco as of December 31, 2013 are $6 million in 2014, $6 million in 2015, $6 million in 2016, $5 million in 2017, $4 million in 2018 and $21 million thereafter.

(13) 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 years ended December 31, 2013, 2012 and 2011 were approximately $209 million, $211 million and $185 million, respectively.

Pepco Energy Services performs utility maintenance services and high voltage underground transmission cabling, including services that are treated as capital costs, for Pepco. Amounts charged to Pepco by Pepco Energy Services for the years ended December 31, 2013, 2012 and 2011 were approximately $20 million, $16 million and $20 million, respectively.

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

	2013	2012
	(millions of dollars)	
(Payable to) Receivable From Related Party (current) (a)		
PHI Service Company	$ (25)	$ (22)
Pepco Energy Services (b)	(7)	(18)
Other	—	(1)
Total	$ (32)	$ (41)

(a) Included in Accounts payable due to associated companies.
(b) Pepco bills customers on behalf of Pepco Energy Services where Pepco Energy Services has performed work for certain government agencies under a General Services Administration area-wide agreement. Amount also includes charges for utility work performed by Pepco Energy Services on behalf of Pepco. Prior to the wind-down of Pepco Energy Services' retail electric and natural gas businesses, Pepco billed customers on behalf of Pepco Energy Services where customers had selected Pepco Energy Services as their alternative energy supplier.

(14) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The quarterly data presented below reflect all adjustments necessary, in the opinion of management, for a fair presentation of the interim results. Quarterly data normally vary seasonally because of temperature variations and differences between summer and winter rates. Therefore, comparisons by quarter within a year are not meaningful.

	2013				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(millions of dollars)				
Total Operating Revenue	$ 477	$ 469	$ 605	$ 475	$2,026
Total Operating Expenses	430	389	476	410	1,705
Operating Income	47	80	129	65	321
Other Expenses	(22)	(23)	(23)	(24)	(92)
Income Before Income Tax Expense	25	57	106	41	229
Income Tax Expense	2(a)	20	40	17	79
Net Income	$ 23	$ 37	$ 66	$ 24	$ 150

(a) Includes tax benefits of $5 million (after-tax) allocated to Pepco associated with interest on uncertain and effectively settled tax positions resulting from a change in assessment of tax benefits associated with the cross-border energy leases of a PHI affiliate.

	2012				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(millions of dollars)				
Total Operating Revenue	$ 465	$ 456	$ 582	$ 445	$1,948
Total Operating Expenses	425	401	475	390	1,691
Operating Income	40	55	107	55	257
Other Expenses	(21)	(20)	(22)	(20)	(83)
Income Before Income Tax Expense	19	35	85	35	174
Income Tax (Benefit) Expense (a)	(5) (a)	8	35	10	48
Net Income	$ 24	$ 27	$ 50	$ 25	$ 126

(a) Includes tax benefits of $10 million (after-tax), primarily related to the settlement of an uncertain tax position with the IRS related 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.

Management's Report on Internal Control over Financial Reporting

The management of Delmarva Power & Light Company (DPL) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management of DPL assessed DPL's internal control over financial reporting as of December 31, 2013 based on the framework in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment, the management of DPL concluded that DPL's internal control over financial reporting was effective as of December 31, 2013.

Report of Independent Registered Public Accounting Firm

To the Shareholder and Board of Directors of
Delmarva Power & Light Company

In our opinion, the financial statements of Delmarva Power & Light Company (a wholly owned subsidiary of Pepco Holdings, Inc.) listed in the accompanying index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Delmarva Power & Light Company at December 31, 2013 and December 31, 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule of Delmarva Power & Light Company listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF INCOME

For the Year Ended December 31,	2013	2012	2011
	(millions of dollars)		
Operating Revenue			
Electric	$1,053	$1,050	$1,074
Natural gas	191	183	230
Total Operating Revenue	1,244	1,233	1,304
Operating Expenses			
Purchased energy	552	568	635
Gas purchased	109	113	155
Other operation and maintenance	251	260	239
Depreciation and amortization	107	102	89
Other taxes	40	36	37
Total Operating Expenses	1,059	1,079	1,155
Operating Income	185	154	149
Other Income (Expenses)			
Interest expense	(50)	(47)	(44)
Other income	10	10	8
Total Other Expenses	(40)	(37)	(36)
Income Before Income Tax Expense	145	117	113
Income Tax Expense	56	44	42
Net Income	$ 89	$ 73	$ 71

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS

ASSETS	December 31, 2013	December 31, 2012
	(millions of dollars)	
CURRENT ASSETS		
Cash and cash equivalents	$ 2	$ 6
Accounts receivable, less allowance for uncollectible accounts of $12 million and $9 million, respectively	208	201
Inventories	51	53
Prepayments of income taxes	10	10
Deferred income tax assets, net	59	11
Income taxes receivable	5	10
Assets and accrued interest related to uncertain tax positions	17	—
Prepaid expenses and other	9	9
Total Current Assets	361	300
OTHER ASSETS		
Goodwill	8	8
Regulatory assets	311	288
Prepaid pension expense	228	232
Assets and accrued interest related to uncertain tax positions	3	20
Other	13	12
Total Other Assets	563	560
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	3,673	3,422
Accumulated depreciation	(1,016)	(1,000)
Net Property, Plant and Equipment	2,657	2,422
TOTAL ASSETS	$ 3,581	$ 3,282

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS

LIABILITIES AND EQUITY	December 31, 2013	December 31, 2012
	(millions of dollars, except shares)	
CURRENT LIABILITIES		
Short-term debt	$ 252	$ 137
Current portion of long-term debt	100	250
Accounts payable	46	40
Accrued liabilities	71	85
Accounts payable due to associated companies	22	20
Taxes accrued	4	4
Interest accrued	6	6
Derivative liabilities	—	4
Other	60	61
Total Current Liabilities	561	607
DEFERRED CREDITS		
Regulatory liabilities	229	258
Deferred income tax liabilities, net	816	697
Investment tax credits	5	5
Other postretirement benefit obligations	23	22
Other	36	41
Total Deferred Credits	1,109	1,023
OTHER LONG-TERM LIABILITIES		
Long-term debt	867	667
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
EQUITY		
Common stock, $2.25 par value, 1,000 shares authorized, 1,000 shares outstanding	—	—
Premium on stock and other capital contributions	407	407
Retained earnings	637	578
Total Equity	1,044	985
TOTAL LIABILITIES AND EQUITY	$ 3,581	$ 3,282

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

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS

For the Year Ended December 31,	2013	2012	2011
		(millions of dollars)	
OPERATING ACTIVITIES			
Net income	$ 89	$ 73	$ 71
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	107	102	89
Deferred income taxes	65	55	57
Investment tax credit amortization	(1)	(1)	(1)
Changes in:			
Accounts receivable	(7)	(15)	26
Inventories	2	(9)	(3)
Regulatory assets and liabilities, net	(42)	(29)	(30)
Accounts payable and accrued liabilities	(1)	26	(23)
Pension contributions	(10)	(85)	(40)
Prepaid pension expense, excluding contributions	14	15	17
Income tax-related prepayments, receivables and payables	(1)	8	14
Other assets and liabilities	(1)	(9)	1
Net Cash From Operating Activities	214	131	178
INVESTING ACTIVITIES			
Investment in property, plant and equipment	(357)	(320)	(229)
Net other investing activities	2	—	(4)
Net Cash Used By Investing Activities	(355)	(320)	(233)
FINANCING ACTIVITIES			
Dividends paid to Parent	(30)	—	(60)
Capital contributions from Parent	—	60	—
Issuances of long-term debt	300	250	35
Reacquisitions of long-term debt	(250)	(97)	(35)
Issuances (repayments) of short-term debt, net	115	(15)	47
Cost of issuances	(3)	(3)	—
Net other financing activities	5	(5)	4
Net Cash From (Used By) Financing Activities	137	190	(9)
Net (Decrease) Increase In Cash and Cash Equivalents	(4)	1	(64)
Cash and Cash Equivalents at Beginning of Year	6	5	69
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 2	$ 6	$ 5
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid for interest (net of capitalized interest of $2 million, $2 million and $1 million, respectively)	$ 47	$ 44	$ 43
Cash received for income taxes (includes payments from PHI for Federal income taxes)	(8)	(24)	(24)
Non-cash activities:			
Reclassification of property, plant and equipment to regulatory assets	—	38	—
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
STATEMENTS OF EQUITY

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
Balance as of December 31, 2010	1,000	$ —	$ 347	$ 494	$ 841
Net Income	—	—	—	71	71
Dividends on common stock	—	—	—	(60)	(60)
Balance as of December 31, 2011	1,000	—	347	505	852
Net Income	—	—	—	73	73
Capital contribution from Parent	—	—	60	—	60
Balance as of December 31, 2012	1,000	—	407	578	985
Net Income	—	—	—	89	89
Dividends on common stock	—	—	—	(30)	(30)
Balance as of December 31, 2013	1,000	$ —	$ 407	$ 637	$1,044

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

NOTES TO FINANCIAL STATEMENTS

DELMARVA POWER & LIGHT COMPANY

(1) ORGANIZATION

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

(2) SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

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

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

Revenue Recognition

DPL recognizes revenues upon distribution of electricity and natural gas to its customers, including unbilled revenue for services rendered, but not yet billed. DPL’s unbilled revenue was $61 million and $62 million as of December 31, 2013 and 2012, respectively, and these amounts are included in Accounts receivable. DPL calculates unbilled revenue using an output-based methodology. This methodology is based on the supply of electricity or natural gas intended for distribution to customers. The unbilled revenue process requires management to make assumptions and judgments about input factors such as customer sales mix, temperature, and estimated line losses (estimates of electricity and natural gas expected to be lost in the process of its transmission and distribution to customers). The assumptions and judgments are inherently uncertain and susceptible to change from period to period, and if the actual results differ from the projected results, the impact could be material. Revenues from non-regulated electricity and natural gas sales are included in Electric revenues and Natural gas revenues, respectively.

Taxes related to the consumption of electricity and natural gas by its customers, such as fuel, energy, or other similar taxes, are components of DPL’s tariffs and, as such, are billed to customers and recorded in Operating revenue. Accruals for the remittance of these taxes by DPL are recorded in Other taxes.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in DPL's gross revenues were $17 million, $15 million and $18 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Accounting for Derivatives

DPL uses derivative instruments primarily to reduce natural gas commodity price volatility and to limit its customers' exposure to natural gas price fluctuations under a hedging program approved by the Delaware Public Service Commission (DPSC). Derivatives are recorded in the balance sheets as Derivative assets or Derivative liabilities and measured at fair value. DPL enters physical natural gas contracts as part of the hedging program that qualify as normal purchases or normal sales, which are not required to be recorded in the financial statements until settled. DPL's capacity contracts are not classified as derivatives. Changes in the fair value of derivatives that are not designated as cash flow hedges are reflected in income.

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 fully recoverable through the fuel adjustment clause approved by the DPSC, and are deferred under Financial Accounting Standards Board (FASB) guidance on regulated operations (Accounting Standards Codification (ASC) 980) until recovered.

Long-Lived Asset Impairment Evaluation

DPL evaluates certain long-lived assets to be held and used (for example, equipment and real estate) for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. Examples of such events or changes include a significant decrease in the market price of a long-lived asset or a significant adverse change in the manner in which an asset is being used or its physical condition. A long-lived asset to be held and used is written down to its estimated fair value if the expected future undiscounted cash flow from the asset is less than its carrying value.

For long-lived assets that can be classified as assets to be disposed of by sale, an impairment loss is recognized to the extent that the assets' carrying value exceeds its estimated fair value including costs to sell.

Income Taxes

DPL, as an indirect subsidiary of Pepco Holdings, is included in the consolidated federal income tax return of PHI. Federal income taxes are allocated to DPL based upon the taxable income or loss amounts, determined on a separate return basis.

The financial statements include current and deferred income taxes. Current income taxes represent the amount of tax expected to be reported on DPL's state income tax returns and the amount of federal income tax allocated from Pepco Holdings.

Deferred income tax assets and liabilities represent the tax effects of temporary differences between the financial statement basis and tax basis of existing assets and liabilities, and they are measured using presently enacted tax rates. The portion of DPL's deferred tax liability applicable to its utility operations that has not been recovered from utility customers represents income taxes recoverable in the future and is included in Regulatory assets on the balance sheets. See Note (7), "Regulatory Matters," for additional information.

Deferred income tax expense generally represents the net change during the reporting period in the net deferred tax liability and deferred recoverable income taxes.

DPL recognizes interest on underpayments and overpayments of income taxes, interest on uncertain tax positions, and tax-related penalties in income tax expense.

Investment tax credits are being amortized to income over the useful lives of the related property.

Consolidation of Variable Interest Entities

DPL assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with ASC 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests. See Note (17), "Variable Interest Entities, " for additional information.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, cash invested in money market funds and commercial paper held with original maturities of three months or less. Additionally, deposits in PHI's money pool, which DPL and certain other PHI subsidiaries use to manage short-term cash management requirements, are considered cash equivalents. Deposits in the money pool are guaranteed by PHI. PHI deposits funds in the money pool to the extent that the pool has insufficient funds to meet the needs of its participants, which may require PHI to borrow funds for deposit from external sources.

Accounts Receivable and Allowance for Uncollectible Accounts

DPL's Accounts receivable balance primarily consists of customer accounts receivable arising from the sale of goods and services to customers within its service territory, other accounts receivable, and accrued unbilled revenue. Accrued unbilled revenue represents revenue earned in the current period but not billed to the customer until a future date (usually within one month after the receivable is recorded).

DPL maintains an allowance for uncollectible accounts and changes in the allowance are recorded as an adjustment to Other operation and maintenance expense in the statements of income. DPL determines the amount of the allowance based on specific identification of material amounts at risk by customer and maintains a reserve based on its historical collection experience. The adequacy of this allowance is assessed on a quarterly basis by evaluating all known factors such as the aging of the receivables, historical collection experience, the economic and competitive environment and changes in the creditworthiness of its customers. Accounts receivable are written off in the period in which the receivable is deemed uncollectible and collection efforts have been exhausted. Recoveries of Accounts receivable previously written off are recorded when it is probable they will be recovered. Although DPL believes its allowance is adequate, it cannot anticipate with any certainty the changes in the financial condition of its customers. As a result, DPL records adjustments to the allowance for uncollectible accounts in the period in which the new information that requires an adjustment to the reserve becomes known.

Inventories

Included in Inventories are transmission and distribution materials and supplies and natural gas. DPL utilizes the weighted average cost method of accounting for inventory items. Under this method, an average price is determined for the quantity of units acquired at each price level and is applied to the ending quantity to calculate the total ending inventory balance. Materials and supplies are recorded in Inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

The cost of natural gas, including transportation costs, is included in Inventory when purchased and charged to Gas purchased expense when used.

Goodwill

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

Regulatory Assets and Regulatory Liabilities

Certain aspects of DPL's business are subject to regulation by the DPSC and the Maryland Public Service Commission (MPSC). The transmission of electricity by DPL is regulated by the Federal Energy Regulatory Commission (FERC). DPL's interstate transportation and wholesale sale of natural gas are regulated by FERC.

Based on the regulatory framework in which it has operated, DPL has historically applied, and in connection with its transmission and distribution business continues to apply, FASB guidance on regulated operations (ASC 980). The guidance allows regulated entities, in appropriate circumstances, to defer the income statement impact of certain costs that are expected to be recovered in future rates through the establishment of regulatory assets and defer certain revenues that are expected to be refunded to customers through the establishment of regulatory liabilities. Management's assessment of the probability of recovery of regulatory assets requires judgment and interpretation of laws, regulatory commission orders and other factors. If management subsequently determines, based on changes in facts or circumstances, that a regulatory asset is not probable of recovery, the regulatory asset would be eliminated through a charge to earnings.

Effective June 2007, the MPSC approved a bill stabilization adjustment (BSA) mechanism for retail customers. For customers to whom the BSA applies, DPL recognizes distribution revenue based on an approved distribution charge per customer. From a revenue recognition standpoint, the BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during that period. Pursuant to this mechanism, DPL recognizes 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 (a Revenue Decoupling Adjustment). A net positive Revenue Decoupling Adjustment is recorded as a regulatory asset and a net negative Revenue Decoupling Adjustment is recorded as a regulatory liability.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The carrying value of Property, plant and equipment is evaluated for impairment whenever circumstances indicate the carrying value of those assets may not be recoverable. Upon retirement, the cost of regulated property, net of salvage, is charged to Accumulated depreciation. For additional information regarding the treatment of asset retirement obligations, see the "Asset Removal Costs" section included in this Note.

The annual provision for depreciation on electric and natural gas property, plant and equipment is computed on a straight-line basis using composite rates by classes of depreciable property. Accumulated depreciation is charged with the cost of depreciable property retired, less salvage and other recoveries. Non-operating and other property is generally depreciated on a straight-line basis over the useful lives of the assets. The system-wide composite annual depreciation rates for the years ended December 31, 2013, 2012 and 2011 for DPL's property were approximately 2.6%, 2.7% and 2.8%, respectively.

Capitalized Interest and Allowance for Funds Used During Construction

In accordance with FASB guidance on regulated operations (ASC 980), utilities can capitalize the capital costs of financing the construction of plant and equipment as Allowance for Funds Used During Construction (AFUDC). This results in the debt portion of AFUDC being recorded as a reduction of Interest expense and the equity portion of AFUDC being recorded as an increase to Other income in the accompanying statements of income.

DPL recorded AFUDC for borrowed funds of $2 million, $2 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

DPL recorded amounts for the equity component of AFUDC of $2 million, $3 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Leasing Activities

DPL’s lease transactions include plant, office space, equipment, software and vehicles. In accordance with FASB guidance on leases (ASC 840), these leases are classified as operating leases.

An operating lease in which DPL is the lessee generally results in a level income statement charge over the term of the lease, reflecting the rental payments required by the lease agreement. If rental payments are not made on a straight-line basis, DPL’s policy is to recognize rent expense on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed.

Amortization of Debt Issuance and Reacquisition Costs

DPL defers and amortizes debt issuance costs and long-term debt premiums and discounts over the lives of the respective debt issuances. When refinancing or redeeming existing debt, any unamortized premiums, discounts and debt issuance costs, as well as debt redemption costs, are classified as Regulatory assets and are amortized generally over the life of the original issue.

Asset Removal Costs

In accordance with FASB guidance, asset removal costs are recorded as regulatory liabilities. At December 31, 2013 and 2012, $173 million and $202 million, respectively, of asset removal costs are included in Regulatory liabilities in the accompanying balance sheets.

Pension and Postretirement Benefit Plans

Pepco Holdings sponsors the PHI Retirement Plan, a non-contributory, defined benefit pension plan that covers substantially all employees of DPL and certain employees of other Pepco Holdings subsidiaries. Pepco Holdings also provides supplemental retirement benefits to certain eligible executives and key employees through nonqualified retirement plans and provides certain postretirement health care and life insurance benefits for eligible retired employees.

The PHI Retirement Plan is accounted for in accordance with FASB guidance on retirement benefits (ASC 715).

Dividend Restrictions

All of DPL’s shares of outstanding common stock are held by Conectiv, its parent company. In addition to its future financial performance, the ability of DPL to pay dividends to its parent company is subject to limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by DPL and any other restrictions imposed in connection with the incurrence of liabilities. DPL has no shares of preferred stock outstanding. DPL had approximately $637 million and $578 million of retained earnings available for payment of common stock dividends at December 31, 2013 and 2012, respectively. These amounts represent the total retained earnings balances at those dates.

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 individually or in the aggregate to either the current period or prior period financial results:

Natural Gas Operating Revenue Adjustment

During 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 year ended December 31, 2012.

Default Electricity Supply Revenue and Costs 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 $11 million for the year ended December 31, 2011.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

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

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, DPL will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. DPL will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between DPL and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements are effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. DPL does not expect this new guidance to have a material impact on its financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with DPL's March 31, 2014 financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. DPL does not expect this new guidance to have a material impact on its financial statements.

(5) SEGMENT INFORMATION

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

(6) GOODWILL

All of DPL's goodwill was generated by its acquisition of Conowingo Power Company in 1995. In order to estimate the fair value of the DPL reporting unit, DPL uses two valuation techniques: an income approach and a market approach. The income approach estimates fair value based on a discounted future cash flow analysis and a terminal value that is consistent with DPL's long-term view of the business. This approach uses a discount rate based on the estimated weighted average cost of capital (WACC) for the reporting unit. DPL determines the estimated WACC by considering appropriate market-based information for the cost of equity and cost of debt as of the measurement date . The market approach estimates fair value based on a multiple of earnings before interest, taxes, depreciation, and amortization (EBITDA) that management believes is consistent with EBITDA multiples for comparable utilities. DPL has consistently used this valuation technique to estimate the fair value of the DPL reporting unit.

The estimation of fair value is dependent on a number of factors including but not limited to interest rates, growth assumptions, returns on rate base, operating and capital expenditure requirements, and other factors, changes in which could materially affect the results of impairment testing. Assumptions used were consistent with historical experience, including assumptions concerning the recovery of operating costs and capital expenditures and current market-based information. Sensitive, interrelated and uncertain variables that could decrease the estimated fair value of the DPL reporting unit include utility sector market performance, sustained adverse business conditions, changes in forecasted revenues, higher operating and maintenance capital expenditure requirements, a significant increase in the weighted average cost of capital and other factors.

As of December 31, 2013 and 2012, DPL's goodwill balance was $8 million. There are no accumulated impairment losses.

(7) REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

The components of DPL's regulatory asset and liability balances at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Regulatory Assets		
Smart Grid costs (a)	$ 83	$ 71
Recoverable income taxes	76	69
MAPP abandonment costs (a)	31	38
Demand-side management costs (a)	27	12
COPCO acquisition adjustment (a)	22	26
Deferred debt extinguishment costs (a)	13	15
Deferred energy supply costs (b)	13	13
Incremental storm restoration costs (a)	9	11
Deferred losses on gas derivatives	—	4
Other	37	29
Total Regulatory Assets	$ 311	$ 288
Regulatory Liabilities		
Asset removal costs	$ 173	$ 202
Deferred income taxes due to customers	37	38
Deferred energy supply costs	3	6
Deferred gains on gas derivatives	1	—
Other	15	12
Total Regulatory Liabilities	$ 229	$ 258

(a) A return is earned on these deferrals.
(b) A return is generally earned in Delaware on this deferral.

A description for each category of regulatory assets and regulatory liabilities follows:

Smart Grid Costs: Represents advanced metering infrastructure (AMI) costs associated with the installation of smart meters and the early retirement of existing meters throughout DPL's service territory that are recoverable from customers.

Recoverable Income Taxes: Represents amounts recoverable from DPL's customers for tax benefits applicable to utility operations that were previously recognized in income tax expense before the company was ordered to account for the tax benefits as deferred income taxes. As the temporary differences between the financial statement basis and tax basis of assets reverse, the deferred recoverable balances are reversed.

MAPP Abandonment Costs: Represents the probable recovery of abandoned costs prudently incurred in connection with the Mid-Atlantic Power Pathway (MAPP) project which was terminated on August 24, 2012. The regulatory asset includes the costs of land, land rights, supplies and materials, engineering and design, environmental services, and project management and administration. The regulatory asset will be reduced as the result of sale or alternative use of these assets. As of December 31, 2013, these assets were earning a return of 12.8%. For additional information, see "MAPP Project" discussion below.

Demand-Side Management Costs: Represents recoverable costs associated with customer energy efficiency and conservation programs in DPL's Maryland jurisdiction.

COPCO Acquisition Adjustment: On July 19, 2007, the MPSC issued an order which provided for the recovery of a portion of DPL's goodwill. As a result of this order, $41 million in DPL goodwill was transferred to a regulatory asset. This item is being amortized from August 2007 through August 2018. The return earned is 12.95%.

Deferred Debt Extinguishment Costs: Represents the costs of debt extinguishment associated with issuances of debt for which recovery through regulated utility rates is considered probable, and if approved, will be amortized to interest expense during the authorized rate recovery period.

Deferred Energy Supply Costs: The regulatory asset represents primarily deferred costs associated with a net under-recovery of Default Electricity Supply costs incurred by DPL that are probable of recovery in rates. The regulatory liability represents primarily deferred costs associated with a net over-recovery of Default Electricity Supply costs incurred that will be refunded by DPL to customers.

Incremental Storm Restoration Costs: Represents total incremental storm restoration costs incurred for repair work due to major storm events in 2012 and 2011, including Hurricane Sandy, the June 2012 derecho, and Hurricane Irene, that are recoverable from customers in the Maryland jurisdiction. DPL's costs related to Hurricane Sandy, the June 2012 derecho and Hurricane Irene are being amortized and recovered in rates, each over a five-year period.

Deferred Losses on Gas Derivatives: Represents losses associated with hedges of natural gas purchases that are recoverable through the Gas Cost Rate approved by the DPSC.

Other: Represents miscellaneous regulatory assets that generally are being amortized over 1 to 20 years.

Asset Removal Costs: The depreciation rates for DPL include a component for removal costs, as approved by the relevant federal and state regulatory commissions. Accordingly, DPL has recorded regulatory liabilities for its estimate of the difference between incurred removal costs and the amount of removal costs recovered through depreciation rates.

Deferred Income Taxes Due to Customers: Represents the portions of deferred income tax assets applicable to utility operations of DPL that have not been reflected in current customer rates for which future payment to customers is probable. As the temporary differences between the financial statement basis and tax basis of assets reverse, deferred recoverable income taxes are amortized.

Deferred Gains on Gas Derivatives: Represents gains associated with hedges of natural gas purchases that will be refunded to customers through the Gas Cost Rate approved by the DPSC.

Other: Includes miscellaneous regulatory liabilities.

Rate Proceedings

Bill Stabilization Adjustment

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

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

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

<u>*Delaware*</u>

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $39 million (as adjusted by DPL on September 20, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase seeks to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on June 1, 2013, subject to refund and pending final DPSC approval. On October 8, 2013, the DPSC approved DPL's request to implement an additional interim increase of $25.1 million, effective on October 22, 2013, bringing the total interim rates in effect subject to refund to $27.6 million. A final DPSC decision is expected by the second quarter of 2014.

Forward Looking Rate Plan

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

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

On October 22, 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that it would not address the FLRP until the pending electric distribution base rate case discussed above was concluded. DPL expects that the FLRP will be updated and re-filed at the conclusion of the electric distribution base rate case. A schedule for the FLRP docket has not yet been established.

Gas Distribution Base Rates

On December 7, 2012, DPL submitted an application with the DPSC to increase its natural gas distribution base rates. The filing sought approval of an annual rate increase of approximately $12.0 million (as adjusted by DPL on July 15, 2013), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing efforts to maintain safe and reliable gas service. On October 22, 2013, the DPSC approved a settlement entered into on August 27, 2013 by the DPSC Staff, the Delaware Division of the Public Advocate and DPL, which provides for an annual rate increase of $6.8 million. While the approved settlement provided that no understanding was reached concerning the appropriate ROE, it specified that for reporting purposes and for calculating the AFUDC, construction work in process (CWIP), regulatory asset carrying costs and other accounting metrics, the rate of 9.75% should be used. The new rates became effective on November 1, 2013.

The approved settlement also provides for a phase-in of the recovery of the deferred costs associated with DPL's deployment of the interface management unit (IMU). The IMU is part of its AMI and allows for the remote reading of gas meters. Recovery of such costs will occur through base rates over a two-year period, assuming specific milestones are met and pursuant to the following schedule: 50% of the IMU portion of DPL's AMI will be put into rates on May 1, 2014, and the remainder will be put into rates on March 1, 2015. DPL also agreed in the settlement that its next natural gas distribution base rate application may be filed with the DPSC no earlier than January 1, 2015.

Gas Cost Rates

DPL makes an annual Gas Cost Rate (GCR) filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. On August 28, 2013, DPL made its 2013 GCR filing. The rates proposed in the 2013 GCR filing would result in a GCR decrease of approximately 5.5%. On September 26, 2013, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2013, subject to refund and pending final DPSC approval.

Maryland

On March 29, 2013, DPL submitted an application with the MPSC to increase its electric distribution base rates by approximately $22.8 million, based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. DPL also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $10.2 million associated with its plan to accelerate investments in electric distribution infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force (as discussed below under "Resiliency Task Forces"). Specific projects under DPL's Grid Resiliency Charge plan included accelerating its tree-trimming cycle and upgrading five additional feeders per year for two years. In addition, DPL proposed a reliability performance-based mechanism that would allow DPL to earn up to $500,000 as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $500,000 in total if DPL did not meet at least the minimum reliability performance targets. DPL requested that any credits or charges would flow through the proposed Grid Resiliency Charge rider.

On August 30, 2013, the MPSC issued a final order approving a settlement among DPL, the MPSC staff and the Maryland Office of People's Counsel (OPC). The approved settlement provides for an annual rate increase of approximately $15 million. While the settlement does not specify an overall ROE, the parties did agree that the ROE for purposes of calculating the AFUDC and regulatory asset carrying costs would be 9.81%. The approved settlement also provides for (i) recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by amortizing the related deferred operation and maintenance expenses of approximately $6 million over a five-year period with the unamortized balance included in rate base, and (ii) a Grid Resiliency Charge for recovery of costs totaling approximately $4.2 million associated with DPL's proposed plan to accelerate investments related to certain priority feeders, provided that before implementing the surcharge, DPL provides additional information to the MPSC related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The approved settlement does not provide for approval of a portion of the Grid Resiliency Charge related to the proposed acceleration of the tree-trimming cycle, or DPL's proposed reliability performance-based mechanism. The new rates became effective on September 15, 2013.

Federal Energy Regulatory Commission

On October 17, 2013, FERC issued a ruling on challenges filed by the Delaware Municipal Electric Corporation, Inc. (DEMEC) to DPL's 2011 and 2012 annual formula rate updates. In 2006, FERC approved a formula rate for DPL that is incorporated into the PJM Interconnection, LLC (PJM) tariff. The formula rate establishes the treatment of costs and revenues and the resulting rates for DPL. Pursuant to the protocols approved by FERC and after a period of discovery, interested parties have an opportunity to file challenges regarding the application of the formula rate. The FERC order sets various issues in this proceeding for hearing, including challenges regarding formula rate inputs, deferred income items, prepayments of estimated income taxes, rate base reductions, various administrative and general expenses and the inclusion in rate base of CWIP related to the MAPP project (which has been abandoned). Settlement discussions began in this matter on November 5, 2013 before an administrative law judge at FERC.

On December 12, 2013, DEMEC filed a formal challenge to the DPL 2013 annual formula rate update, including a request to consolidate the 2013 challenge with the two prior challenges. This challenge is pending at FERC. PHI cannot predict when a final FERC decision in this proceeding will be issued.

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as DEMEC, filed a joint complaint with FERC against DPL and its affiliates Potomac Electric Power Company (Pepco) and Atlantic City Electric Company (ACE), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that DPL and its utility affiliates provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for DPL and its utility affiliates is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. DPL believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, DPL filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. DPL cannot predict when a final FERC decision in this proceeding will be issued.

MPSC New Generation Contract Requirement

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

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

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

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

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit. These appeals remain pending.

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

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

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 it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. DPL's electric distribution base rate case filed with the MPSC on March 29, 2013 attempted to address the Grid Resiliency Task Force recommendations. In August 2013, the MPSC issued an order in the DPL Maryland electric distribution base rate case that only partially approved the proposed Grid Resiliency Charge. See "Rate Proceedings – Maryland" above for more information about these base rate cases.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. DPL had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, DPL submitted a filing to FERC seeking recovery of approximately $38 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs.

On December 18, 2013, DPL submitted a settlement agreement to FERC, which provides for recovery of DPL's abandoned MAPP costs over a three-year recovery period beginning June 1, 2013. The settlement agreement, which is subject to FERC approval, would resolve all issues concerning the recovery of abandonment costs associated with the cancellation of the MAPP project. DPL cannot predict the timing or results of a final FERC decision in this proceeding.

As of December 31, 2013, DPL had a regulatory asset related to the MAPP abandoned costs of approximately $31 million, representing the original filing amount of approximately $38 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; and (ii) $6 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration.

(8) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	Original Cost	Accumulated Depreciation	Net Book Value
		(millions of dollars)	
At December 31, 2013			
Distribution	$1,788	$ 492	$ 1,296
Transmission	982	243	739
Gas	481	142	339
Construction work in progress	158	—	158
Non-operating and other property	264	139	125
Total	$3,673	$ 1,016	$ 2,657
At December 31, 2012			
Distribution	$1,664	$ 498	$ 1,166
Transmission	877	233	644
Gas	458	137	321
Construction work in progress	206	—	206
Non-operating and other property	217	132	85
Total	$3,422	$ 1,000	$ 2,422

The non-operating and other property amounts include balances for general plant, plant held for future use, intangible plant and non-utility property. Utility plant is generally subject to a first mortgage lien.

(9) 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 (the PHI OPEB Plan), as participation in multiemployer plans. For 2013, 2012 and 2011, DPL was responsible for $18 million, $23 million and $23 million, respectively, of the pension and other postretirement net periodic benefit cost incurred by PHI. DPL made discretionary tax-deductible contributions to the PHI Retirement Plan of $10 million, $85 million and $40 million for the years ended December 31, 2013, 2012 and 2011, respectively. In addition, DPL made contributions of $3 million, $7 million and $6 million, respectively, to the PHI OPEB Plan for the years ended December 31, 2013, 2012 and 2011. At December 31, 2013 and 2012, DPL's Prepaid pension expense of $228 million and $232 million, respectively, and Other postretirement benefit obligations of $23 million and $22 million, respectively, effectively represent assets and benefit obligations resulting from DPL's participation in the PHI benefit plans.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and the retiree life insurance benefits, and were effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $3 million reduction in DPL's net periodic benefit cost for other postretirement benefits in 2013. Approximately 29% of net periodic other postretirement benefit costs were capitalized in 2013.

(10) DEBT

Long-Term Debt

The components of long-term debt are shown in the table below:

Type of Debt	Interest Rate	Maturity	2013	2012
			(millions of dollars)	
First Mortgage Bonds				
	6.40%	2013	$ —	$ 250
	5.22%(a)	2016	100	100
	3.50%	2023	300	—
	4.00%	2042	250	250
			650	600
Unsecured Tax-Exempt Bonds				
	5.40%	2031	78	78
			78	78
Medium-Term Notes (unsecured)				
	7.56%-7.58%	2017	14	14
	6.81%	2018	4	4
	7.61%	2019	12	12
	7.72%	2027	10	10
			40	40
Notes (unsecured)				
	5.00%	2014	100	100
	5.00%	2015	100	100
			200	200
Total long-term debt			968	918
Net unamortized discount			(1)	(1)
Current portion of long-term debt			(100)	(250)
Total net long-term debt			$ 867	$ 667

(a) Represents a series of Collateral First Mortgage Bonds securing a series of debt securities issued by DPL.

The outstanding first mortgage bonds issued by DPL are issued under a Mortgage and Deed of Trust and are secured by a first lien on substantially all of DPL's property, plant and equipment, except for certain property excluded from the lien of the mortgage.

Maturities of DPL's long-term debt outstanding at December 31, 2013 are $100 million for each year 2014 through 2016, $14 million in 2017, $4 million in 2018 and $650 million thereafter.

DPL's long-term debt is subject to certain covenants. As of December 31, 2013, DPL is in compliance with all such covenants.

The table above does not separately identify $100 million in aggregate principal amount of debt securities issued by DPL. These debt securities are secured by a like amount of first mortgage bonds (Collateral First Mortgage Bonds) of DPL. The principal terms of each such series of debt securities, are identical to the same terms of the corresponding series of Collateral First Mortgage Bonds. Payments of principal and interest made on a series of such debt securities, satisfy the corresponding obligations on the related series of Collateral First Mortgage Bonds. For these reasons, each such series of Collateral First Mortgage Bonds and the corresponding debt securities together effectively represent a single financial obligation and are not identified in the table above separately.

Bond Issuances

During 2013, DPL issued $300 million of 3.50% first mortgage bonds due November 15, 2023. The net proceeds from the issuance of the long-term debt were used to repay at maturity $250 million of 6.40% first mortgage bonds, plus accrued but unpaid interest thereon, to repay outstanding commercial paper and for general corporate purposes.

Bond Redemptions

During 2013, DPL repaid at maturity $250 million of its 6.40% first mortgage bonds.

Short-Term Debt

DPL has traditionally used a number of sources to fulfill short-term funding needs, such as commercial paper, short-term notes, and bank lines of credit. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements. The components of DPL's short-term debt at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Variable rate demand bonds	$ 105	$ 105
Commercial paper	147	32
	$ 252	$ 137

Commercial Paper

DPL maintains an ongoing commercial paper program to address its short-term liquidity needs. As of December 31, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had $147 million and $32 million of commercial paper outstanding at December 31, 2013 and 2012, respectively. The weighted average interest rates for commercial paper issued by DPL during 2013 and 2012 were 0.29% and 0.43%, respectively. The weighted average maturity of all commercial paper issued by DPL during 2013 and 2012 was three days and four days, respectively.

Variable Rate Demand Bonds

Variable Rate Demand Bonds (VRDBs) are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. DPL expects that any bonds submitted for purchase will continue to be remarketed successfully due to the creditworthiness of the company and because the remarketing agent resets the interest rate to the then-current market rate. The bonds may be converted to a fixed rate, fixed term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, DPL views VRDBs as a source of long-term financing. The VRDBs outstanding in 2013 mature as follows: 2017 ($26 million), 2024 ($33 million), 2028 ($16 million), and 2029 ($30 million). The weighted average interest rate for VRDBs was 0.26% during 2013 and 0.38% during 2012. As of December 31, 2013, $105 million in VRDBs issued on behalf of DPL were outstanding (of which $72 million were secured by Collateral First Mortgage Bonds issued by DPL).

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On August 1, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained the same.

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

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

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of December 31, 2013.

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

As of December 31, 2013 and 2012, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $332 million and $477 million, respectively. DPL's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by Pepco and ACE and the portion of the total capacity being used by PHI.

(11) INCOME TAXES

DPL, as an indirect subsidiary of PHI, is included in the consolidated federal income tax return of PHI. Federal income taxes are allocated to DPL pursuant to a written tax sharing agreement that was approved by the Securities and Exchange Commission in connection with the establishment of PHI as a holding company. Under this tax sharing agreement, PHI's consolidated federal income tax liability is allocated based upon PHI's and its subsidiaries' separate taxable income or loss.

The provision for income taxes, reconciliation of income tax expense, and components of deferred income tax liabilities (assets) are shown below.

Provision for Income Taxes

	For the Year Ended December 31, 2013	2012 (millions of dollars)	2011
Current Tax (Benefit) Expense			
Federal	$ (8)	$ (9)	$ (22)
State and local	—	(1)	8
Total Current Tax Benefit	(8)	(10)	(14)
Deferred Tax Expense (Benefit)			
Federal	53	44	53
State and local	12	11	4
Investment tax credit amortization	(1)	(1)	(1)
Total Deferred Tax Expense	64	54	56
Total Income Tax Expense	$ 56	$ 44	$ 42

Reconciliation of Income Tax Expense

	For the Year Ended December 31, 2013		2012 (millions of dollars)		2011	
Income tax at Federal statutory rate	$ 51	35.0%	$ 41	35.0%	$40	35.0%
Increases (decreases) resulting from:						
State income taxes, net of Federal effect	8	5.5%	6	5.1%	6	5.3%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	—	—	(3)	(2.7)%
Other, net	(3)	(1.9)%	(3)	(2.5)%	(1)	(0.4)%
Income Tax Expense	$ 56	38.6%	$ 44	37.6%	$42	37.2%

Year ended December 31, 2013

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

Year ended December 31, 2011

During 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, DPL recorded a $4 million (after-tax) interest benefit. This is partially offset by 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 the recalculation of interest on its uncertain tax positions for open tax years based on different assumptions related to the application of its deposit made with the IRS in 2006 resulting in an additional tax expense of $1 million (after-tax).

Components of Deferred Income Tax Liabilities (Assets)

	As of December 31,	
	2013	2012
	(millions of dollars)	
Deferred Tax Liabilities (Assets)		
Depreciation and other basis differences related to plant and equipment	$ 712	$ 623
Deferred taxes on amounts to be collected through future rates	16	15
Federal and state net operating losses	(125)	(80)
Pension and other postretirement benefits	80	85
Electric restructuring liabilities	(5)	(5)
Other	80	49
Total Deferred Tax Liabilities, net	758	687
Deferred tax assets included in Current Assets	59	11
Deferred tax liabilities included in Other Current Liabilities	(1)	(1)
Total Deferred Tax Liabilities, net non-current	$ 816	$ 697

The net deferred tax liability represents the tax effect, at presently enacted tax rates, of temporary differences between the financial statement basis and tax basis of assets and liabilities. The portion of the net deferred tax liability applicable to DPL's operations, which has not been reflected in current service rates, represents income taxes recoverable through future rates, net, and is recorded as a regulatory asset on the balance sheet. No valuation allowance for deferred tax assets was required or recorded at December 31, 2013 and 2012. Federal and state net operating losses generally expire over 20 years from 2029 to 2032.

The Tax Reform Act of 1986 repealed the investment tax credit for property placed in service after December 31, 1985, except for certain transition property. Investment tax credits previously earned on DPL's property continue to be amortized to income over the useful lives of the related property.

Reconciliation of Beginning and Ending Balances of Unrecognized Tax Benefits

	2013	2012	2011
		(millions of dollars)	
Balance as of January 1	$ 9	$ 35	$ 40
Tax positions related to current year:			
Additions	—	—	—
Reductions	—	—	—
Tax positions related to prior years:			
Additions	—	—	7
Reductions	—	(26)(a)	(12)
Settlements	—	—	—
Balance as of December 31	$ 9	$ 9	$ 35

(a) These reductions of unrecognized tax benefits in 2012 primarily relate to a resolution reached with the IRS for determining deductible mixed service costs for additions to property, plant and equipment.

Unrecognized Benefits That, If Recognized, Would Affect the Effective Tax Rate

Unrecognized tax benefits are related to tax positions that have been taken or are expected to be taken in tax returns that are not recognized in the financial statements because management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or has concluded that it is not more likely than not that the tax position will be ultimately sustained. For the majority of these tax positions, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. At December 31, 2013, DPL had $1 million of unrecognized tax benefits that, if recognized, would lower the effective tax rate.

Interest and Penalties

DPL recognizes interest and penalties relating to its uncertain tax positions as an element of income tax expense. For the years ended December 31, 2013, 2012 and 2011, DPL recognized less than $1 million of pre-tax interest income, less than $1 million of pre-tax interest income and $6 million of pre-tax interest income ($4 million after-tax), respectively, as a component of income tax expense. As of December 31, 2013, 2012 and 2011, DPL had accrued interest receivable of $2 million, accrued interest receivable of $1 million and accrued interest receivable of $1 million, respectively, related to effectively settled and uncertain tax positions.

Possible Changes to Unrecognized Tax Benefits

It is reasonably possible that the amount of the unrecognized tax benefit with respect to some of DPL’s uncertain tax positions will significantly increase or decrease within the next 12 months. PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues of DPL for open tax years 2001 through 2011. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014, which could significantly impact the balances of unrecognized tax benefits and the related interest accruals of DPL. At this time, it is estimated that there will be a $4 million to $6 million decrease in unrecognized tax benefits within the next 12 months.

Tax Years Open to Examination

DPL, as an indirect subsidiary of PHI, is included on PHI’s consolidated Federal tax return. DPL’s federal income tax liabilities for all years through 2002 have been determined, subject to adjustment to the extent of any net operating loss or other loss or credit carrybacks from subsequent years. The open tax years for the significant states where DPL files state income tax returns (Maryland and Delaware) are the same as for the Federal returns.

Final IRS Regulations on Repair of Tangible Property

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

Other Taxes

Taxes other than income taxes for each year are shown below. These amounts are recoverable through rates.

	2013	2012	2011
	(millions of dollars)		
Gross Receipts/Delivery	$15	$14	$15
Property	24	21	19
Environmental, Use and Other	1	1	3
Total	$40	$36	$37

(12) 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 December 31, 2013 and 2012:

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

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

All derivative assets and liabilities available to be offset under master netting arrangements were netted as of December 31, 2013 and 2012. The amount of cash collateral that was offset against these derivative positions is as follows:

	December 31, 2013	December 31, 2012
	(millions of dollars)	
Cash collateral received from counterparties with the obligation to return	$ (1)	$ —

As of December 31, 2013 and 2012, 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. For the years ended December 31, 2013, 2012 and 2011, DPL had no net unrealized derivative losses and zero, zero and $5 million, respectively, of net realized losses associated with cash flow hedges recognized in the statements of income (through Purchased energy or Gas purchased expense) that were deferred as Regulatory assets.

Other Derivative Activity

DPL holds certain derivatives that are not in hedge accounting relationships and are not designated as normal purchases or normal sales. These derivatives are recorded at fair value on the balance sheets with the gain or loss for changes in the fair value recorded in income. In accordance with FASB guidance on regulated operations, offsetting regulatory liabilities or regulatory assets are recorded on the balance sheets and the recognition of the derivative gain or loss is deferred because of the DPSC-approved fuel adjustment clause. For the years ended December 31, 2013, 2012 and 2011, 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 are provided in the table below:

	For the Year Ended December 31, 2013	2012	2011
	(millions of dollars)		
Net unrealized gain (loss) arising during the period	$ 1	$ (3)	$ (13)
Net realized loss recognized during the period	(4)	(16)	(22)

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

	December 31, 2013		December 31, 2012	
Commodity	Quantity	Net Position	Quantity	Net Position
Natural Gas (One Million British Thermal Units (MMBtu))	3,977,500	Long	3,838,000	Long

Contingent Credit Risk Features

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

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

The gross fair value of DPL's derivative liabilities with credit-risk-related contingent features on December 31, 2013 and 2012, was zero and $4 million, respectively. As of those dates, DPL had posted no cash collateral in the normal course of business against its gross derivative liabilities. If DPL's debt ratings had been downgraded below investment grade as of December 31, 2013 and 2012, DPL's net settlement amounts would have been approximately zero and $2 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately zero and $2 million, respectively. The net settlement and additional collateral amounts reflect the effect of offsetting transactions under master netting agreements.

DPL's primary sources for posting cash collateral or letters of credit are PHI's credit facilities, under which DPL is a borrower. As of December 31, 2013 and 2012, the aggregate amount of cash plus borrowing capacity under the credit facilities available to meet the liquidity needs of PHI's utility subsidiaries was $332 million and $477 million, respectively.

(13) 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 December 31, 2013 and 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. DPL's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

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

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2012			
	(millions of dollars)			
ASSETS				
Executive deferred compensation plan assets				
Money market funds	$ 2	$ 2	$ —	$ —
Life insurance contracts	1	—	—	1
	$ 3	$ 2	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ —	$ —	$ 4
	$ 4	$ —	$ —	$ 4

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

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

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

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

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

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

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

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

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

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

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

Reconciliations of the beginning and ending balances of DPL's fair value measurements using significant unobservable inputs (Level 3) for the years ended December 31, 2013 and 2012 are shown below:

	Year Ended December 31, 2013		Year Ended December 31, 2012	
	Natural Gas	Life Insurance Contracts	Natural Gas	Life Insurance Contracts
	(millions of dollars)			
Balance as of January 1	$ (4)	$ 1	$ (15)	$ 1
Total gains (losses) (realized and unrealized):				
Included in income	—	—	—	—
Included in accumulated other comprehensive loss	—	—	—	—
Included in regulatory liabilities	—	—	(2)	—
Purchases	—	—	—	—
Issuances	—	—	—	—
Settlements	4	—	13	—
Transfers in (out) of Level 3	—	—	—	—
Balance as of December 31	$ —	$ 1	$ (4)	$ 1

Other Financial Instruments

The estimated fair values of DPL's Long-term debt instruments that are measured at amortized cost in DPL's financial statements and the associated level of the estimates within the fair value hierarchy as of December 31, 2013 and 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. DPL's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

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

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

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

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

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

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

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

(14) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, DPL is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. DPL is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, DPL's contracts with its vendors generally require the vendors to name DPL as an additional insured for the amount at least equal to DPL's self-insured retention. Further, DPL's contracts with its vendors require the vendors to indemnify DPL for various acts and activities that may give rise to claims against DPL. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on DPL's financial condition, results of operations or cash flows. At December 31, 2013, DPL had loss contingency liabilities for general litigation totaling approximately $2 million.

Environmental Matters

DPL is subject to regulation by various federal, regional, state, and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from DPL's customers, environmental clean-up costs incurred by DPL generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of DPL described below at December 31, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Other	Total
		(millions of dollars)		
Balance as of January 1	$ 1	$ 3	$ 2	$ 6
Accruals	—	—	1	1
Payments	—	(1)	(3)	(4)
Balance as of December 31	1	2	—	3
Less amounts in Other Current Liabilities	1	1	—	2
Amounts in Other Deferred Credits	$ —	$ 1	$ —	$ 1

Ward Transformer Site

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

Indian River Oil Release

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

Metal Bank Site

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

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

Contractual Obligations

Power Purchase Contracts

As of December 31, 2013, DPL's contractual obligations under non-derivative power purchase contracts were $64 million in 2014, $131 million in 2015 to 2016, $131 million in 2017 to 2018, and $300 million in 2019 and thereafter.

Lease Commitments

DPL leases an 11.9% interest in the Merrill Creek Reservoir. The lease is an operating lease and payments over the remaining lease term, which ends in 2032, are $84 million in the aggregate. DPL also has long-term leases for certain other facilities and equipment. Total future minimum operating lease payments for DPL, including the Merrill Creek Reservoir lease, as of December 31, 2013, are $13 million in 2014, $13 million in 2015, $11 million in 2016, $10 million in 2017, $14 million in 2018, and $111 million thereafter.

Rental expense for operating leases, including the Merrill Creek Reservoir lease, was $13 million, $12 million and $11 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(15) 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 years ended December 31, 2013, 2012 and 2011 were $154 million, $153 million and $133 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:

	For the Year Ended December 31, 2013	2012	2011
		(millions of dollars)	
Purchased power under Default Electricity Supply contracts with Conectiv Energy Supply, Inc. (a)	$ —	$ —	$ 1
Intercompany lease transactions (b)	4	4	5

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

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

	2013	2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (22)	$ (19)
Other	—	(1)
Total	$ (22)	$ (20)

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

(16) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The quarterly data presented below reflect all adjustments necessary, in the opinion of management, for a fair presentation of the interim results. Quarterly data normally vary seasonally because of temperature variations and differences between summer and winter rates. Therefore, comparisons by quarter within a year are not meaningful.

	2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(millions of dollars)		
Total Operating Revenue	$ 370	$ 266	$ 296	$ 312	$1,244
Total Operating Expenses	317	235	249	258	1,059
Operating Income	53	31	47	54	185
Other Expenses	(11)	(10)	(10)	(9)	(40)
Income Before Income Tax Expense	42	21	37	45	145
Income Tax Expense	16	9	14	17	56
Net Income	$ 26	$ 12	$ 23	$ 28	$ 89

	2012 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(millions of dollars)		
Total Operating Revenue	$ 333	$ 259	$ 340	$ 301	$1,233
Total Operating Expenses	290	229	297	263	1,079
Operating Income	43	30	43	38	154
Other Expenses	(8)	(8)	(10)	(11)	(37)
Income Before Income Tax Expense	35	22	33	27	117
Income Tax Expense	14	9	11	10	44
Net Income	$ 21	$ 13	$ 22	$ 17	$ 73

(17) VARIABLE INTEREST ENTITIES

DPL is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if DPL is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. DPL performed a qualitative analysis to determine whether a variable interest provided a controlling financial interest in a VIE at December 31, 2013, which is described below.

DPL is subject to Renewable Energy Portfolio Standards (RPS) in the state of Delaware that require it to obtain renewable energy credits (RECs) for energy delivered to its customers. DPL's costs associated with obtaining RECs to fulfill its RPS obligations are recoverable from its customers by law. As of December 31, 2013, DPL is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 MWs and one solar PPA with a 10 MW facility. Each of the facilities associated with these PPAs is operational, and DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and solar renewable energy credits (SRECs) from the solar facility up to certain amounts (as set forth below) at rates that are primarily fixed under the respective PPA. DPL has concluded that while VIEs exist under these contracts, consolidation is not required for any of these PPAs under the FASB guidance on the consolidation of variable interest entities as DPL is not the primary beneficiary. DPL has not provided financial or other support under these arrangements that it was not previously contractually required to provide during the periods presented, nor does DPL have any intention to provide such additional support.

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

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from the second wind facility through 2031 in amounts not to exceed 40 MWs, and from the third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's purchases under the three wind PPAs totaled $30 million, $27 million and $18 million for the years ended December 31, 2013, 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 $3 million, $2 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to fuel cell facilities totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL would be an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour (MWh) of energy produced by the fuel cell facilities over 21 years. DPL has no obligation to the qualified fuel cell provider other than to remit payments collected from its distribution customers pursuant to the tariff. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. At December 31, 2013 and 2012, 15 MWs and 3 MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $23 million and $4 million to distribution customers during the years ended December 31, 2013 and 2012, respectively. DPL has concluded that while a VIE exists under this arrangement, consolidation is not required for this arrangement under the FASB guidance on consolidation of variable interest entities as DPL is not the primary beneficiary.

Management's Report on Internal Control over Financial Reporting

The management of Atlantic City Electric Company (ACE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management of ACE assessed ACE's internal control over financial reporting as of December 31, 2013 based on the framework in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment, the management of ACE concluded that ACE's internal control over financial reporting was effective as of December 31, 2013.

Report of Independent Registered Public Accounting Firm

To the Shareholder and Board of Directors of
Atlantic City Electric Company

In our opinion, the consolidated financial statements of Atlantic City Electric Company (a wholly owned subsidiary of Pepco Holdings, Inc.) listed in the accompanying index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Atlantic City Electric Company and its subsidiary at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule of Atlantic City Electric Company listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Year Ended December 31,	2013	2012	2011
		(millions of dollars)	
Operating Revenue	$ 1,202	$ 1,198	$ 1,268
Operating Expenses			
Purchased energy	660	703	807
Other operation and maintenance	230	239	226
Depreciation and amortization	136	124	134
Other taxes	14	18	25
Deferred electric service costs	26	(5)	(63)
Total Operating Expenses	1,066	1,079	1,129
Operating Income	136	119	139
Other Income (Expenses)			
Interest expense	(68)	(70)	(69)
Other income	1	4	2
Total Other Expenses	(67)	(66)	(67)
Income Before Income Tax Expense	69	53	72
Income Tax Expense	19	18	33
Net Income	$ 50	$ 35	$ 39

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

ASSETS	December 31, 2013	December 31, 2012
	(millions of dollars)	
CURRENT ASSETS		
Cash and cash equivalents	$ 3	$ 6
Restricted cash equivalents	10	10
Accounts receivable, less allowance for uncollectible accounts of $10 million and $11 million, respectively	186	192
Inventories	28	30
Prepayments of income taxes	17	27
Income taxes receivable	118	5
Assets and accrued interest related to uncertain tax positions	12	—
Prepaid expenses and other	16	11
Total Current Assets	390	281
OTHER ASSETS		
Regulatory assets	569	694
Prepaid pension expense	106	88
Income taxes receivable	29	133
Restricted cash equivalents	14	17
Assets and accrued interest related to uncertain tax positions	5	12
Derivative assets	—	8
Other	12	12
Total Other Assets	735	964
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	2,901	2,771
Accumulated depreciation	(751)	(787)
Net Property, Plant and Equipment	2,150	1,984
TOTAL ASSETS	$ 3,275	$ 3,229

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

LIABILITIES AND EQUITY	December 31, 2013	December 31, 2012
	(millions of dollars, except shares)	
CURRENT LIABILITIES		
Short-term debt	$ 138	$ 133
Current portion of long-term debt	148	108
Accounts payable	21	26
Accrued liabilities	105	121
Accounts payable due to associated companies	15	14
Taxes accrued	12	10
Interest accrued	13	15
Customer deposits	22	25
Other	23	22
Total Current Liabilities	497	474
DEFERRED CREDITS		
Regulatory liabilities	57	102
Deferred income tax liabilities, net	833	766
Investment tax credits	5	6
Other postretirement benefit obligations	35	34
Derivative liabilities	—	11
Other	14	18
Total Deferred Credits	944	937
OTHER LONG-TERM LIABILITIES		
Long-term debt	753	760
Transition Bonds issued by ACE Funding	214	256
Total Other Long-Term Liabilities	967	1,016
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
EQUITY		
Common stock, $3.00 par value, 25,000,000 shares authorized, 8,546,017 shares outstanding	26	26
Premium on stock and other capital contributions	651	576
Retained earnings	190	200
Total Equity	867	802
TOTAL LIABILITIES AND EQUITY	$ 3,275	$ 3,229

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Year Ended December 31,	2013	2012	2011
	(millions of dollars)		
OPERATING ACTIVITIES			
Net income	$ 50	$ 35	$ 39
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	136	124	134
Deferred income taxes	53	62	42
Investment tax credit amortization	(1)	(1)	(1)
Changes in:			
Accounts receivable	7	(7)	26
Inventories	2	(5)	(8)
Regulatory assets and liabilities, net	19	(33)	(74)
Accounts payable and accrued liabilities	4	12	(18)
Pension contributions	(30)	(30)	(30)
Income tax-related prepayments, receivables and payables	(6)	(43)	45
Other assets and liabilities	12	19	16
Net Cash From Operating Activities	246	133	171
INVESTING ACTIVITIES			
Investment in property, plant and equipment	(261)	(256)	(138)
Department of Energy capital reimbursement awards received	2	2	4
Net other investing activities	3	(1)	(9)
Net Cash Used By Investing Activities	(256)	(255)	(143)
FINANCING ACTIVITIES			
Dividends paid to Parent	(60)	(35)	—
Capital contributions from Parent	75	—	60
Redemption of preferred stock	—	—	(6)
Issuances of long-term debt	100	—	200
Reacquisitions of long-term debt	(108)	(41)	(35)
Issuances (repayments) of short-term debt, net	6	110	(158)
Net other financing activities	(6)	3	(2)
Net Cash From Financing Activities	7	37	59
Net (Decrease) Increase In Cash and Cash Equivalents	(3)	(85)	87
Cash and Cash Equivalents at Beginning of Year	6	91	4
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 3	$ 6	$ 91
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid for interest (net of capitalized interest of less than $1 million, $2 million and $2 million, respectively)	$ 67	$ 68	$ 64
Cash (received) paid for income taxes (includes payments to (from) PHI for Federal income taxes)	(21)	1	(51)

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF EQUITY

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
Balance as of December 31, 2010	8,546,017	$ 26	$ 516	$ 161	$703
Net Income	—	—	—	39	39
Capital contribution from Parent	—	—	60	—	60
Balance as of December 31, 2011	8,546,017	26	576	200	802
Net Income	—	—	—	35	35
Dividends on common stock	—	—	—	(35)	(35)
Balance as of December 31, 2012	8,546,017	26	576	200	802
Net Income	—	—	—	50	50
Dividends on common stock	—	—	—	(60)	(60)
Capital contribution from Parent	—	—	75	—	75
Balance as of December 31, 2013	8,546,017	$ 26	$ 651	$ 190	$867

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 (Conectiv), which is wholly owned by Pepco Holdings, Inc. (Pepco Holdings or PHI).

(2) SIGNIFICANT ACCOUNTING POLICIES

Consolidation Policy

The accompanying consolidated financial statements include the accounts of ACE and its wholly owned subsidiary Atlantic City Electric Transition Funding, LLC (ACE Funding). All intercompany balances and transactions between subsidiaries have been eliminated. ACE uses the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies where it holds an interest and can exercise significant influence over the operations and policies of the entity. Certain transmission and other facilities currently held are consolidated in proportion to ACE's percentage interest in the facility.

Use of Estimates

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

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

Revenue Recognition

ACE recognizes revenue upon distribution of electricity to its customers, including unbilled revenue for electricity delivered but not yet billed. ACE's unbilled revenue was $36 million and $39 million as of December 31, 2012 and 2011, respectively, and these amounts are included in Accounts receivable. ACE calculates unbilled revenue using an output-based methodology. This methodology is based on the supply of electricity intended for distribution to customers. The unbilled revenue process requires management to make assumptions and judgments about input factors such as customer sales mix, temperature, and estimated line losses (estimates of electricity expected to be lost in the process of its transmission and distribution to customers). The assumptions and judgments are inherently uncertain and susceptible to change from period to period, and if the actual results differ from the projected results, the impact could be material.

Taxes related to the consumption of electricity by its customers are a component of ACE's tariffs and, as such, are billed to customers and recorded in Operating revenue. Accruals for the remittance of these taxes by ACE are recorded in Other taxes.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in ACE's gross revenues were $11 million, $15 million and $22 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Accounting for Derivatives

ACE began applying derivative accounting to two of its Standard Offer Capacity Agreements (SOCAs), as of June 30, 2012 because the generators cleared the 2015-2016 PJM Interconnection, LLC (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 New Jersey Board of Public Utilities (NJBPU) has ordered that ACE is obligated to distribute to or recover from its distribution customers, all payments received or made by ACE, respectively, under the SOCAs. See Note (6), "Regulatory Matters," for additional information on the SOCAs.

Long-Lived Asset Impairment Evaluation

ACE evaluates certain long-lived assets to be held and used (for example, equipment and real estate) for impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. Examples of such events or changes include a significant decrease in the market price of a long-lived asset or a significant adverse change in the manner in which an asset is being used or its physical condition. A long-lived asset to be held and used is written down to its estimated fair value if the expected future undiscounted cash flow from the asset is less than its carrying value.

For long-lived assets that can be classified as assets to be disposed of by sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value including costs to sell.

Income Taxes

ACE, as an indirect subsidiary of Pepco Holdings, is included in the consolidated federal income tax return of PHI. Federal income taxes are allocated to ACE based upon the taxable income or loss amounts, determined on a separate return basis.

The consolidated financial statements include current and deferred income taxes. Current income taxes represent the amount of tax expected to be reported on ACE's state income tax returns and the amount of federal income tax allocated from Pepco Holdings.

Deferred income tax assets and liabilities represent the tax effects of temporary differences between the financial statement basis and tax basis of existing assets and liabilities, and they are measured using presently enacted tax rates. The portion of ACE's deferred tax liability applicable to its utility operations that has not been recovered from utility customers represents income taxes recoverable in the future and is included in Regulatory assets on the consolidated balance sheets. See Note (6), "Regulatory Matters," for additional information.

Deferred income tax expense generally represents the net change during the reporting period in the net deferred tax liability and deferred recoverable income taxes.

ACE recognizes interest on underpayments and overpayments of income taxes, interest on uncertain tax positions, and tax-related penalties in income tax expense.

Investment tax credits are being amortized to income over the useful lives of the related property.

Consolidation of Variable Interest Entities

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

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, cash invested in money market funds and commercial paper held with original maturities of three months or less. Additionally, deposits in PHI’s money pool, which ACE and certain other PHI subsidiaries use to manage short-term cash management requirements, are considered cash equivalents. Deposits in the money pool are guaranteed by PHI. PHI deposits funds in the money pool to the extent that the pool has insufficient funds to meet the needs of its participants, which may require PHI to borrow funds for deposit from external sources.

Restricted Cash Equivalents

The Restricted cash equivalents included in Current assets and the Restricted cash equivalents included in Other assets consist of (i) cash held as collateral that is restricted from use for general corporate purposes and (ii) cash equivalents that are specifically segregated based on management’s intent to use such cash equivalents for a particular purpose. The classification as current or non-current conforms to the classification of the related liabilities.

Accounts Receivable and Allowance for Uncollectible Accounts

ACE’s Accounts receivable balance primarily consists of customer accounts receivable arising from the sale of goods and services to customers within its service territories, other accounts receivable, and accrued unbilled revenue. Accrued unbilled revenue represents revenue earned in the current period but not billed to the customer until a future date (usually within one month after the receivable is recorded).

ACE maintains an allowance for uncollectible accounts and changes in the allowance are recorded as an adjustment to Other operation and maintenance expense in the consolidated statements of income. ACE determines the amount of allowance based on specific identification of material amounts at risk by customer and maintains a reserve based on its historical collection experience. The adequacy of this allowance is assessed on a quarterly basis by evaluating all known factors such as the aging of the receivables, historical collection experience, the economic and competitive environment and changes in the creditworthiness of its customers. Accounts receivable are written off in the period in which the receivable is deemed uncollectible and collection efforts have been exhausted. Recoveries of Accounts receivable previously written off are recorded when it is probable they will be recovered. Although ACE believes its allowance is adequate, it cannot anticipate with any certainty the changes in the financial condition of its customers. As a result, ACE records adjustments to the allowance for uncollectible accounts in the period in which the new information that requires an adjustment to the reserve becomes known.

Inventories

Included in inventories are transmission and distribution materials and supplies. ACE utilizes the weighted average cost method of accounting for inventory items. Under this method, an average price is determined for the quantity of units acquired at each price level and is applied to the ending quantity to calculate the total ending inventory balance. Materials and supplies are recorded in Inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Regulatory Assets and Regulatory Liabilities

Certain aspects of ACE's business are subject to regulation by the NJBPU. The transmission of electricity by ACE is regulated by the Federal Energy Regulatory Commission (FERC).

Based on the regulatory framework in which it has operated, ACE has historically applied, and in connection with its transmission and distribution business continues to apply, FASB guidance on regulated operations (ASC 980). The guidance allows regulated entities, in appropriate circumstances, to defer the income statement impact of certain costs that are expected to be recovered in future rates through the establishment of regulatory assets and defer certain revenues that are expected to be refunded to customers through the establishment of regulatory liabilities. Management's assessment of the probability of recovery of regulatory assets requires judgment and interpretation of laws, regulatory commission orders and other factors. If management subsequently determines, based on changes in facts or circumstances, that a regulatory asset is not probable of recovery, the regulatory asset would be eliminated through a charge to earnings.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs, including capitalized interest. The carrying value of Property, plant and equipment is evaluated for impairment whenever circumstances indicate the carrying value of those assets may not be recoverable. Upon retirement, the cost of regulated property, net of salvage, is charged to accumulated depreciation.

The annual provision for depreciation on electric property, plant and equipment is computed on a straight-line basis using composite rates by classes of depreciable property. Accumulated depreciation is charged with the cost of depreciable property retired, less salvage and other recoveries. Non-operating and other property is generally depreciated on a straight-line basis over the useful lives of the assets. The system-wide composite annual depreciation rates for the years ended December 31, 2013, 2012 and 2011 for ACE's property were approximately 2.8%, 3.0% and 3.0%, respectively.

In 2010, ACE was awarded $19 million from the U.S. Department of Energy (DOE) to fund a portion of the costs incurred for the implementation of direct load control, distribution automation and communications infrastructure in its New Jersey service territory. ACE has elected to recognize the award proceeds as a reduction in the carrying value of the assets acquired rather than grant income over the service period.

Capitalized Interest and Allowance for Funds Used During Construction

In accordance with FASB guidance on regulated operations (ASC 980), utilities can capitalize the capital costs of financing the construction of plant and equipment as Allowance for Funds Used During Construction (AFUDC). This results in the debt portion of AFUDC being recorded as a reduction of Interest expense and the equity portion of AFUDC being recorded as an increase to Other income in the accompanying consolidated statements of income.

ACE recorded AFUDC for borrowed funds of less than $1 million for the year ended December 31, 2013, $2 million for the year ended December 31, 2012 and $2 million for the year ended December 31, 2011.

ACE recorded amounts for the equity component of AFUDC of less than $1 million for the year ended December 31, 2013, $3 million for the year ended December 31, 2012 and less than $1 million for the year ended December 31, 2011.

Leasing Activities

ACE’s lease transactions include plant, office space, equipment, software and vehicles. In accordance with FASB guidance on leases (ASC 840), these leases are classified as operating leases.

An operating lease in which ACE is the lessee generally results in a level income statement charge over the term of the lease, reflecting the rental payments required by the lease agreement. If rental payments are not made on a straight-line basis, ACE’s policy is to recognize rent expense on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the time pattern in which the leased property is physically employed.

Amortization of Debt Issuance and Reacquisition Costs

ACE defers and amortizes debt issuance costs and long-term debt premiums and discounts over the lives of the respective debt issuances. When refinancing or redeeming existing debt, any unamortized premiums, discounts and debt issuance costs, as well as debt redemption costs, are classified as regulatory assets and are amortized generally over the life of the original issue.

Pension and Postretirement Benefit Plans

Pepco Holdings sponsors the PHI Retirement Plan, a non-contributory, defined benefit pension plan that covers substantially all employees of ACE and certain employees of other Pepco Holdings subsidiaries. Pepco Holdings also provides supplemental retirement benefits to certain eligible executives and key employees through nonqualified retirement plans and provides certain postretirement health care and life insurance benefits for eligible retired employees.

The PHI Retirement Plan is accounted for in accordance with FASB guidance on retirement benefits (ASC 715).

Dividend Restrictions

All of ACE’s shares of outstanding common stock are held by Conectiv, its parent company. In addition to its future financial performance, the ability of ACE to pay dividends to its parent company is subject to limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and the regulatory requirement that ACE obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by ACE and any other restrictions imposed in connection with the incurrence of liabilities; and (iii) certain provisions of the charter of ACE which impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. Currently, the restriction in the ACE charter does not limit its ability to pay common stock dividends. ACE had approximately $190 million and $200 million of retained earnings available for payment of common stock dividends at December 31, 2013 and 2012, respectively. These amounts represent the total retained earnings balances at those dates.

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 individually or in the aggregate to either the current period or prior period financial results:

Deferred Electric Service Costs Adjustments

In 2012, ACE recorded an adjustment to correct errors associated with its calculation of deferred electric service costs. This adjustment resulted in an increase of $3 million to deferred electric service costs, all of which relates to periods prior to 2012.

Income Tax Expense

During 2011, ACE completed a reconciliation of its deferred taxes associated with certain regulatory assets and recorded adjustments which resulted in an increase to income tax expense of $1 million for the year ended December 31, 2011.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

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

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, ACE will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. ACE will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between ACE and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements are effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. ACE does not expect this new guidance to have a material impact on its consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with ACE’s March 31, 2014 consolidated financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. ACE does not expect this new guidance to have a material impact on its consolidated financial statements.

(5) SEGMENT INFORMATION

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

(6) REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

The components of ACE's regulatory asset and liability balances at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Regulatory Assets		
Securitized stranded costs (a)	$ 350	$ 416
Deferred energy supply costs (a)	117	166
Recoverable income taxes	42	33
Incremental storm restoration costs	26	34
ACE SOCAs	—	11
Other	34	34
Total Regulatory Assets	$ 569	$ 694
Regulatory Liabilities		
Deferred energy supply costs	$ 38	$ 62
Federal and state tax benefits, related to securitized stranded costs	13	16
Excess depreciation reserve	—	11
ACE SOCAs	—	8
Other	6	5
Total Regulatory Liabilities	$ 57	$ 102

(a) A return is generally earned on these deferrals.

A description for each category of regulatory assets and regulatory liabilities follows:

Securitized Stranded Costs: Certain contract termination payments under a contract between ACE and an unaffiliated non-utility generator (NUG) and costs associated with the regulated operations of ACE's electricity generation business are no longer recoverable through customer rates (collectively referred to as "stranded costs"). The stranded costs are amortized over the life of Transition Bonds issued by ACE Funding to securitize the recoverability of these stranded costs. These Transition Bonds mature between 2013 and 2023. A customer surcharge is collected by ACE to fund principal and interest payments on the Transition Bonds.

Deferred Energy Supply Costs: The regulatory asset represents primarily deferred costs associated with a net under-recovery of Basic Generation Service costs incurred by ACE that are probable of recovery in rates. The regulatory liability represents primarily deferred costs associated with a net over-recovery of Basic Generation Service costs incurred that will be refunded by ACE to customers.

Recoverable Income Taxes: Represents amounts recoverable from ACE's customers for tax benefits applicable to utility operations previously recognized in income tax expense before the company was ordered to account for the tax benefits as deferred income taxes. As the temporary differences between the financial statement basis and tax basis of assets reverse, the deferred recoverable balances are reversed.

Incremental Storm Restoration Costs: Represents total incremental storm restoration costs incurred for repair work due to major storm events in 2012 and 2011, including Hurricane Sandy, the June 2012 derecho, and Hurricane Irene, that are recoverable from customers in the New Jersey jurisdiction. ACE's costs related to Hurricane Sandy, the June 2012 derecho and Hurricane Irene are being amortized and recovered in rates, each over a three-year period.

ACE SOCAs: The regulatory asset represented unrealized losses associated with the SOCAs that ACE had entered into by order of the NJBPU. The NJBPU had ordered full recovery from distribution customers of payments made by ACE related to the SOCAs. Since these unrealized losses were non-cash, the related regulatory asset does not earn a return. The regulatory liability represented unrealized gains associated with the SOCAs that ACE had entered into by order of the NJBPU. The NJBPU had ordered that any amounts that ACE receives related to the SOCAs be remitted to its distribution customers. As further discussed below, ACE has derecognized their regulatory assets and liabilities related to the SOCAs in the fourth quarter of 2013.

Other: Represents miscellaneous regulatory assets that generally are being amortized over 1 to 20 years.

Federal and State Tax Benefits, Related to Securitized Stranded Costs: Securitized stranded costs include a portion attributable to the future tax benefit expected to be realized when the higher tax basis of the generating facilities divested by ACE is deducted for New Jersey state income tax purposes, as well as the future benefit to be realized through the reversal of federal excess deferred taxes. To account for the possibility that these tax benefits may be given to ACE's customers through lower rates in the future, ACE established a regulatory liability. The regulatory liability related to federal excess deferred taxes will remain until such time as the Internal Revenue Service (IRS) issues its final regulations with respect to normalization of these federal excess deferred taxes.

Excess Depreciation Reserve: The excess depreciation reserve was recorded as part of an ACE New Jersey rate case settlement. This excess reserve is the result of a change in estimated depreciable lives and a change in depreciation technique from remaining life to whole life that caused an over-recovery for depreciation expense from customers when the remaining life method had been used. The excess was amortized as a reduction in Depreciation and amortization expense over an 8.25 year period, and expired in 2013.

Other: Includes miscellaneous regulatory liabilities.

Rate Proceedings

Bill Stabilization Adjustment

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

Electric Distribution Base Rates

On December 11, 2012, ACE submitted an application with the NJBPU, updated on January 4, 2013, to increase its electric distribution base rates by approximately $70.4 million (excluding sales-and-use taxes), based on a requested return on equity (ROE) of 10.25%. This proposed net increase was comprised of (i) a proposed increase to ACE's distribution rates of approximately $72.1 million and (ii) a net decrease to ACE's Regulatory Asset Recovery Charge (a customer charge to recover deferred, NJBPU-approved expenses incurred as part of ACE's public service obligation) in the amount of approximately $1.7 million. The requested rate increase seeks to recover expenses associated with ACE's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. and to recover system restoration costs associated with the derecho storm in June 2012 and Hurricane Sandy in October 2012. On June 21, 2013, the NJBPU approved a settlement of the parties providing for an increase in ACE's electric distribution base rates in the amount of $25.5 million, based on an ROE of 9.75%. The base distribution revenue increase includes full recovery of the approximately $70.0 million in incremental storm restoration costs incurred as a result of recent major storm events, including the derecho storm and Hurricane Sandy, by including the related capital costs of approximately $44.2 million in rate base and amortizing the related deferred operation and maintenance expenses of approximately $25.8 million over a three-year period. Rates were effective on July 1, 2013.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012 and March 2013, ACE submitted petitions with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program for low income customers) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. In June 2012, the NJBPU approved a stipulation of settlement related to ACE's February 2012 filing, which provided for an overall annual rate increase of $55.3 million that went into effect on July 1, 2012. In May 2013, the NJBPU approved a stipulation of settlement related to ACE's March 2013 filing, which provided for an overall annual rate increase of $52.2 million (in addition to the $55.3 million approved by the NJBPU in June 2012) that went into effect on June 1, 2013. These rate increases, which primarily provide for the recovery of above-market costs associated with the NUG contracts and will have no effect on ACE's operating income, were placed into effect provisionally and were subject to a review by the NJBPU of the final underlying costs for reasonableness and prudence. On February 19, 2014, the NJBPU approved a stipulation of settlement for both proceedings, which made final the provisional rates that went into effect on July 1, 2012 and June 1, 2013, respectively.

Service Extension Contributions Refund Order

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

Generic Consolidated Tax Adjustment Proceeding

In January 2013, the NJBPU initiated a generic proceeding to examine whether a consolidated tax adjustment (CTA) should continue to be used, and if so, how it should be calculated in determining a utility's cost of service. Under the NJBPU's current policy, when a New Jersey utility is included in a consolidated group income tax return, an allocated amount of any reduction in the consolidated group's taxes as a result of losses by affiliates is used to reduce the utility's rate base, upon which the utility earns a return. Consequently, this policy has substantially reduced ACE's rate base and ACE's position is that the CTA should be eliminated. A stakeholder process has been initiated by the NJBPU to aid in this examination. No formal schedule has been set for the remainder of the proceeding or for the issuance of a decision.

Federal Energy Regulatory Commission

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc., filed a joint complaint with FERC against ACE and its affiliates Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company (DPL), as well as Baltimore Gas and Electric Company. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that ACE and its utility affiliates provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for ACE and its utility affiliates is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. ACE believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, ACE filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable. ACE cannot predict when a final FERC decision in this proceeding will be issued.

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 (13), “Derivative Instruments and Hedging Activities.” ACE and the other New Jersey electric distribution companies (EDCs) entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators, were dismissed without prejudice subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. On October 11, 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause, and is therefore null and void. On October 21, 2013 a joint motion to stay the Federal district court’s decision pending appeal was filed by the NJBPU and one of the SOCA generation companies. In that motion, the NJBPU notified the Federal district court that it would take no action to force implementation of the SOCAs pending the appeal or such other action—such as FERC approval of the SOCAs—that would cure the constitutional issues to the Federal district court’s satisfaction. On October 25, 2013, the Federal district court issued an order denying the joint motion to stay and ruling that the SOCAs are void, invalid and unenforceable. On October 31, 2013, one of the SOCA generation companies filed a notice of appeal of the October 25, 2013 Federal district court decision with the U.S. Court of Appeals for the Third Circuit (the Federal circuit court). On November 8, 2013, the other remaining SOCA generating company filed a motion to intervene in the proceedings and a notice of appeal of the October 25, 2013 Federal district court decision. On November 21, 2013, the NJBPU filed its notice of appeal of the October 25, 2013 Federal district court decision. On November 14, 2013, the Federal circuit court granted the motion to intervene and on December 13, 2013, the Federal circuit court issued an order consolidating the appeals filed by the NJBPU and the SOCA generating companies of the October 25, 2013 Federal district court decision. The matter has been placed on an expedited schedule and appeal proceedings remain pending. The Federal circuit court is tentatively scheduled to hear the appeal on March 27, 2014.

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

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

(7) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	Original Cost	Accumulated Depreciation	Net Book Value
		(millions of dollars)	
At December 31, 2013			
Generation	$ 10	$ 9	$ 1
Distribution	1,821	442	1,379
Transmission	786	221	565
Construction work in progress	110	—	110
Non-operating and other property	174	79	95
Total	$2,901	$ 751	$ 2,150
At December 31, 2012			
Generation	$ 10	$ 9	$ 1
Distribution	1,707	461	1,246
Transmission	740	214	526
Construction work in progress	133	—	133
Non-operating and other property	181	103	78
Total	$2,771	$ 787	$ 1,984

The non-operating and other property amounts include balances for general plant, plant held for future use, intangible plant and non-utility property. Utility plant is generally subject to a first mortgage lien.

Jointly Owned Plant

ACE's consolidated balance sheets include its proportionate share of assets and liabilities related to jointly owned plant. At December 31, 2013 and 2012, ACE's subsidiaries had a net book value ownership interest of $8 million in transmission and other facilities in which various parties also have ownership interests. ACE's share of the operating and maintenance expenses of the jointly-owned plant is included in the corresponding expenses in the consolidated statements of income. ACE is responsible for providing its share of the financing for the above jointly-owned facilities.

(8) 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 (the PHI OPEB Plan), as participation in multiemployer plans. For 2013, 2012 and 2011, ACE was responsible for $17 million, $24 million and $21 million, respectively, of the pension and other postretirement net periodic benefit cost incurred by PHI. ACE made discretionary tax-deductible contributions to the PHI Retirement Plan of $30 million in each of the years ended December 31, 2013, 2012 and 2011. In addition, ACE made contributions of $6 million, $7 million and $7 million, respectively, to the PHI OPEB Plan for the years ended December 31, 2013, 2012 and 2011. At December 31, 2013 and 2012, ACE's Prepaid pension expense of $106 million and $88 million, and Other postretirement benefit obligations of $35 million and $34 million, respectively, effectively represent assets and benefit obligations resulting from ACE's participation in the PHI benefit plans.

Other Postretirement Benefit Plan Amendments

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree health care and the retiree life insurance benefits, and were effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its accumulated postretirement benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $2 million reduction in ACE's net periodic benefit cost for other postretirement benefits in 2013. Approximately 42% of net periodic other postretirement benefit costs were capitalized in 2013.

(9) DEBT

Long-Term Debt

The components of long-term debt are shown in the table below:

Type of Debt	Interest Rate	Maturity	2013	2012
			(millions of dollars)	
First Mortgage Bonds				
	6.63%	2013	$ —	$ 69
	7.63% (a)	2014	7	7
	7.68% (a)	2015-2016	17	17
	7.75%	2018	250	250
	6.80% (b)(c)	2021	39	39
	4.35%	2021	200	200
	4.875% (d)(c)	2029	23	23
	5.80% (b)(e)	2034	120	120
	5.80% (b)(e)	2036	105	105
			761	830
Variable Rate Term Loan			100	—
Total long-term debt			861	830
Net unamortized discount			(1)	(1)
Current portion of long-term debt			(107)	(69)
Total net long-term debt			$ 753	$ 760

(a) Represents a series of Collateral First Mortgage Bonds securing a series of medium term notes issued by ACE.
(b) Represents a series of Collateral First Mortgage Bonds (as defined herein) which must be cancelled and released as security for ACE's obligations under the corresponding series of issuer notes (as defined herein) or tax-exempt bonds, at such time as ACE does not have any first mortgage bonds outstanding (other than its Collateral First Mortgage Bonds).
(c) Represents a series of Collateral First Mortgage Bonds securing a series of tax-exempt bonds issued for the benefit of ACE.
(d) Represents a series of Collateral First Mortgage Bonds which must be cancelled and released as security for ACE's obligations under the corresponding series of issuer notes or tax-exempt bonds, at such time as ACE does not have any first mortgage bonds outstanding (other than its Collateral First Mortgage Bonds), except that ACE may not permit such release of collateral unless ACE substitutes comparable obligations for such collateral.
(e) Represents a series of Collateral First Mortgage Bonds securing a series of senior notes issued by ACE.

The outstanding first mortgage bonds issued by ACE are issued under a mortgage and deed of trust and are secured by a first lien on substantially all of ACE's property, plant and equipment, except for certain property excluded from the lien of the mortgage.

Maturities of ACE's long-term debt outstanding at December 31, 2013 are $107 million in 2014, $15 million in 2015, $2 million in 2016, zero in 2017, $250 million in 2018 and $487 million thereafter.

ACE's long-term debt is subject to certain covenants. As of December 31, 2013, ACE was in compliance with all such covenants.

The table above which does not separately identify $249 million in aggregate principal amount of senior notes and medium term notes (issuer notes) issued by ACE and $62 million in aggregate principal amount of tax-exempt bonds issued for the benefit of ACE. These issuer notes and tax-exempt bonds are secured by a like amount of first mortgage bonds (Collateral First Mortgage Bonds) of ACE. The principal terms of each such series of issuer notes, or ACE's obligations in respect of each such series of tax-exempt bonds, are identical to the same terms of the corresponding series of Collateral First Mortgage Bonds. Payments of principal and interest made on a series of such issuer notes, or the satisfaction of ACE obligations in respect of a series of such tax-exempt bonds, satisfy the corresponding obligations on the related series of Collateral First Mortgage Bonds. For these reasons, each such series of Collateral First Mortgage Bonds and the corresponding issuer notes or tax-exempt bonds together effectively represent a single financial obligation and are not identified in the table above separately.

Bond Redemptions

During 2013, ACE repaid at maturity $69 million of its 6.63% non-callable first mortgage bonds. ACE also funded the redemption, prior to maturity, of $4 million of outstanding weekly variable rate pollution control revenue refunding bonds due 2017, issued by the Pollution Control Financing Authority of Salem County, New Jersey for ACE's benefit.

Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the London Interbank Offered Rate (LIBOR) with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE's Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of December 31, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.92%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of December 31, 2013.

Transition Bonds Issued by ACE Funding

The components of transition bonds are shown in the table below:

Type of Debt	Interest Rate	Maturity	2013	2012
			(millions of dollars)	
Transition Bonds				
	4.46%	2016	$ 8	$ 19
	4.91%	2017	46	75
	5.05%	2020	54	54
	5.55%	2023	147	147
			255	295
Current portion of long-term debt			(41)	(39)
Total net long-term Transition Bonds			$ 214	$ 256

For a description of the Transition Bonds, see Note (16), "Variable Interest Entities – ACE Funding." Maturities of ACE's Transition Bonds outstanding at December 31, 2013 are $41 million in 2014, $44 million in 2015, $46 million in 2016, $35 million in 2017, $31 million in 2018 and $58 million thereafter.

Short-Term Debt

ACE has traditionally used a number of sources to fulfill short-term funding needs, such as commercial paper, short-term notes, and bank lines of credit. Proceeds from short-term borrowings are used primarily to meet working capital needs, but may also be used to temporarily fund long-term capital requirements. The components of ACE's short-term debt at December 31, 2013 and 2012 are as follows:

	2013	2012
	(millions of dollars)	
Commercial paper	$ 120	$ 110
Variable rate demand bonds	18	23
Total	$ 138	$ 133

Commercial Paper

ACE maintains an ongoing commercial paper program to address its short-term liquidity needs. As of December 31, 2013, the maximum capacity available under the program was $350 million, subject to available borrowing capacity under the credit facility.

ACE had $120 million and $110 million of commercial paper outstanding at December 31, 2013 and 2012, respectively. The weighted average interest rates for commercial paper issued by ACE during 2013 and 2012 were 0.31% and 0.41%, respectively. The weighted average maturity of all commercial paper issued by ACE during 2013 and 2012 was four days and three days, respectively.

Variable Rate Demand Bonds

Variable Rate Demand Bonds (VRDBs) are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. ACE expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the company and because the remarketing resets the interest rate to the then-current market rate. The bonds may be converted to a fixed rate, fixed term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, ACE views VRDBs as a source of long-term financing. As of December 31, 2013, $18 million of VRDBs issued on behalf of ACE were outstanding. The outstanding VRDBs all mature in 2014. The weighted average interest rate for VRDBs was 0.11% and 0.18% during 2013 and 2012, respectively.

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On August 1, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained the same.

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

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

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility at December 31, 2013.

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

As of December 31, 2013 and 2012, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $332 million and $477 million, respectively. ACE's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by Pepco and DPL and the portion of the total capacity being used by PHI.

(10) INCOME TAXES

ACE, as an indirect subsidiary of PHI, is included in the consolidated federal income tax return of PHI. Federal income taxes are allocated to ACE pursuant to a written tax sharing agreement that was approved by the Securities and Exchange Commission in connection with the establishment of PHI as a holding company. Under this tax sharing agreement, PHI's consolidated federal income tax liability is allocated based upon PHI's and its subsidiaries' separate taxable income or loss.

The provision for consolidated income taxes, reconciliation of consolidated income tax expense, and components of consolidated deferred income tax liabilities (assets) are shown below.

Provision for Consolidated Income Taxes

	For the Year Ended December 31,		
	2013	2012	2011
		(millions of dollars)	
Current Tax (Benefit) Expense			
Federal	$ (23)	$ (31)	$ (9)
State and local	(10)	(12)	1
Total Current Tax Benefit	(33)	(43)	(8)
Deferred Tax Expense (Benefit)			
Federal	28	46	35
State and local	25	16	7
Investment tax credit amortization	(1)	(1)	(1)
Total Deferred Tax Expense	52	61	41
Total Consolidated Income Tax Expense	$ 19	$ 18	$ 33

Reconciliation of Consolidated Income Tax Expense

	For the Year Ended December 31,					
	2013		2012		2011	
			(millions of dollars)			
Income tax at Federal statutory rate	$24	35.0%	$19	35.0%	$ 25	35.0%
Increases (decreases) resulting from:						
State income taxes, net of Federal effect	5	7.2%	3	5.7%	4	6.0%
Change in estimates and interest related to uncertain and effectively settled tax positions	(9)	(13.0)%	(1)	(1.9)%	5	6.9%
Plant basis adjustments	(2)	(2.9)%	(1)	(1.9)%	—	—
Investment tax credit amortization	(1)	(1.4)%	(1)	(1.9)%	(1)	(1.3)%
Other, net	2	2.6%	(1)	(1.0)%	—	(0.8)%
Consolidated Income Tax Expense	$19	27.5%	$18	34.0%	$ 33	45.8%

Year ended December 31, 2013

ACE's consolidated effective income tax rate for the year ended December 31, 2013 of 27.5% includes income tax benefits totaling $9 million related to uncertain and effectively settled tax positions.

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

Year ended December 31, 2012

ACE's consolidated effective income tax rate for the year ended December 31, 2012 of 34.0% reflects a $1 million benefit associated with the effective settlement with the Internal Revenue Service (IRS) with respect to the methodology used historically to calculate deductible mixed service costs.

Year ended December 31, 2011

ACE's consolidated effective income tax rate for the year ended December 31, 2011 of 45.8% includes a charge totaling $5 million related to uncertain and effectively settled tax positions.

During 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 has recorded a $1 million (after-tax) interest charge in the second quarter of 2011. Additionally, in the third quarter of 2011, ACE recorded a $3 million (after-tax) interest charge 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.

Components of Consolidated Deferred Income Tax Liabilities (Assets)

	As of December 31,	
	2013	**2012**
	(millions of dollars)	
Deferred Tax Liabilities (Assets)		
Depreciation and other basis differences related to plant and equipment	$ 627	$ 538
Deferred taxes on amounts to be collected through future rates	16	15
Payment for termination of purchased power contracts with NUGs	43	47
Deferred electric service and electric restructuring liabilities	96	116
Pension and other postretirement benefits	29	34
Purchased energy	2	3
Federal and state net operating loss	(49)	(54)
Other	55	58
Total Deferred Tax Liabilities, net	819	757
Deferred tax assets included in Current Assets	15	10
Deferred tax liabilities included in Other Current Liabilities	(1)	(1)
Total Consolidated Deferred Tax Liabilities, net non-current	$ 833	$ 766

The net deferred tax liability represents the tax effect, at presently enacted tax rates, of temporary differences between the financial statement basis and tax basis of assets and liabilities. The portion of the net deferred tax liability applicable to ACE's operations, which has not been reflected in current service rates, represents income taxes recoverable through future rates, net, and is recorded as a regulatory asset on the balance sheet. No valuation allowance for deferred tax assets was required or recorded at December 31, 2013 and 2012. Federal and State net operating losses generally expire over 20 years from 2029 to 2032.

The Tax Reform Act of 1986 repealed the investment tax credit for property placed in service after December 31, 1985, except for certain transition property. Investment tax credits previously earned on ACE's property continue to be amortized to income over the useful lives of the related property.

Reconciliation of Beginning and Ending Balances of Unrecognized Tax Benefits

	2013	2012	2011
		(millions of dollars)	
Balance as of January 1	$ 17	$ 79	$ 83
Tax positions related to current year:			
Additions	2	1	2
Reductions	—	—	—
Tax positions related to prior years:			
Additions	1	8	4
Reductions	(5)	(69)(a)	(10)
Settlements	(6)	(2)	—
Balance as of December 31	$ 9	$ 17	$ 79

(a) These reductions of unrecognized tax benefits in 2012 primarily relate to a resolution reached with the IRS for determining deductible mixed service costs for additions to property, plant and equipment.

Unrecognized Benefits That, If Recognized, Would Affect the Effective Tax Rate

Unrecognized tax benefits are related to tax positions that have been taken or are expected to be taken in tax returns that are not recognized in the financial statements because management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or has concluded that it is not more likely than not that the tax position will be ultimately sustained. For the majority of these tax positions, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. At December 31, 2013, ACE had no unrecognized tax benefits that, if recognized, would lower the effective tax rate.

Interest and Penalties

ACE recognizes interest and penalties relating to its uncertain tax positions as an element of income tax expense. For the years ended December 31, 2013, 2012 and 2011, ACE recognized $12 million of pre-tax interest income ($7 million after-tax), $2 million of pre-tax interest income ($1 million after-tax), and $5 million of pre-tax interest expense ($3 million after-tax), respectively, as a component of income tax expense. As of December 31, 2013, 2012 and 2011, ACE had accrued interest receivable of $14 million, $7 million and $6 million, respectively, related to effectively settled and uncertain tax positions.

Possible Changes to Unrecognized Tax Benefits

It is reasonably possible that the amount of the unrecognized tax benefit with respect to some of ACE's uncertain tax positions will significantly increase or decrease within the next 12 months. PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues of ACE for open tax years 2001 through 2011. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2014, which could significantly impact the balances of unrecognized tax benefits and the related interest accruals of ACE. At this time, it is estimated that there will be a $4 million to $6 million decrease in unrecognized tax benefits within the next 12 months.

Tax Years Open to Examination

ACE, as an indirect subsidiary of PHI, is included on PHI's consolidated Federal tax return. ACE's federal income tax liabilities for all years through 2002 have been determined, subject to adjustment to the extent of any net operating loss or other loss or credit carrybacks from subsequent years. The open tax years for the significant states where ACE files state income tax returns (New Jersey and Pennsylvania) are the same as for the Federal returns. As a result of the final determination of these years, ACE filed amended state returns receiving $1 million in refunds.

Final IRS Regulations on Repair of Tangible Property

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

Other Taxes

Taxes other than income taxes for each year are shown below. These amounts are recoverable through rates.

	2013	2012	2011
	(millions of dollars)		
Gross Receipts/Delivery	$10	$14	$20
Property	3	3	3
Environmental, Use and Other	1	1	2
Total	$14	$18	$25

(11) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

ACE was ordered to enter into the SOCAs by the NJBPU, and under the SOCAs, ACE would have received payments from or made 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. ACE began applying derivative accounting to two of its SOCAs as of June 30, 2012 because these generators cleared the 2015-2016 PJM capacity auction in May 2012. The fair value of the derivatives embedded in the SOCAs were deferred as Regulatory assets or Regulatory liabilities because the NJBPU allowed full recovery from ACE's distribution customers for any payments made by ACE, and ACE's distribution customers would be entitled to any payments received by ACE.

As further discussed in Note (6), "Regulatory Matters," in light of a Federal district court order, which ruled that the SOCAs are void, invalid and unenforceable, and ACE's subsequent termination of the SOCAs in the fourth quarter of 2013, ACE derecognized the derivative assets and derivative liabilities related to the SOCAs in the fourth quarter of 2013.

As of December 31, 2012, ACE had non-current Derivative assets of $8 million, and non-current Derivative liabilities of $11 million associated with the two SOCAs and offsetting Regulatory liability and Regulatory asset amounts, respectively. As of December 31, 2012, ACE had 180 megawatts (MWs) of capacity in a long position, with no collateral or netting applicable to the capacity. Unrealized gains and losses associated with these capacity derivatives, which netted to unrealized gains of $3 million and unrealized losses of $3 million for the years ended December 31, 2013 and 2012, respectively, have been deferred as Regulatory liabilities and Regulatory assets.

(12) 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 December 31, 2013 and 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. ACE's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

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

	Fair Value Measurements at December 31, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Derivative instruments (b)				
Capacity (c)	$ 8	$ —	$ —	$ 8
Restricted cash equivalents				
Treasury fund	27	27	—	—
	$ 35	$ 27	$ —	$ 8
LIABILITIES				
Derivative instruments (b)				
Capacity (c)	$ 11	$ —	$ —	$ 11
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
	$ 12	$ —	$ 1	$ 11

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

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

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

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

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

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

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

ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external 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. As further discussed in Note (6), "Regulatory Matters," ACE derecognized the derivative assets and derivative liabilities related to the SOCAs in the fourth quarter of 2013.

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 December 31, 2012:

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

ACE used 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 December 31, 2012.

A reconciliation of the beginning and ending balances of ACE's fair value measurements using significant unobservable inputs (level 3) for the years ended December 31, 2013 and 2012 are shown below:

	Capacity Year Ended December 31, 2013 (millions of dollars)	Capacity Year Ended December 31, 2012 (millions of dollars)
Balance as of January 1	$ (3)	$ —
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory liabilities and regulatory assets	3	(3)
Purchases	—	—
Issuances	—	—
Settlements	—	—
Transfers in (out) of level 3	—	—
Balance as of December 31	$ —	$ (3)

Other Financial Instruments

The estimated fair values of ACE's Long-term debt instruments that are measured at amortized cost in ACE's consolidated financial statements and the associated level of the estimates within the fair value hierarchy as of December 31, 2013 and 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 categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and ACE reviews the methodologies and results.

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

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

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

Description	Total	Fair Value Measurements at December 31, 2012 Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,016	$ —	$ 884	$ 132
Transition Bonds (b)	341	—	341	—
	$1,357	$ —	$ 1,225	$ 132

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

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

(13) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, ACE is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. ACE is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, ACE's contracts with its vendors generally require the vendors to name ACE as an additional insured for the amount at least equal to ACE's self-insured retention. Further, ACE's contracts with its vendors require the vendors to indemnify ACE for various acts and activities that may give rise to claims against ACE. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on ACE's financial condition, results of operations or cash flows. At December 31, 2013, ACE had loss contingency liabilities for general litigation totaling approximately $9 million (including amounts related to the matters specifically described below) and the portion of these loss contingency liabilities in excess of the self-insured retention amount was substantially offset by insurance receivables.

Asbestos Claim

In September 2011, an asbestos complaint was filed in the New Jersey Superior Court, Law Division, against ACE (among other defendants) asserting claims under New Jersey's Wrongful Death and Survival statutes. The complaint, filed by the estate of a decedent who was the wife of a former employee of ACE, alleges that the decedent's mesothelioma was caused by exposure to asbestos brought home by her husband on his work clothes. New Jersey courts have recognized a cause of action against a premise owner in a so-called "take home" case if it can be shown that the harm was foreseeable. In this case, the complaint seeks recovery of an unspecified amount of damages for, among other things, the decedent's past medical expenses, loss of earnings, and pain and suffering between the time of injury and death, and asserts a punitive damage claim. At December 31, 2013, ACE has concluded that a loss is probable with respect to this matter and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of December 31, 2013. However, due to the inherent uncertainty of litigation, ACE is unable to estimate a maximum amount of possible loss because the damages sought are indeterminate and the matter involves facts that ACE believes are distinguishable from the facts of the "take-home" cause of action recognized by the New Jersey courts.

Electrical Contact Injury Claims

In October 2010, a farm combine came into and remained in contact with a primary electric line in ACE's service territory in New Jersey. As a result, two individuals operating the combine received fatal electrical contact injuries. While attempting to rescue those two individuals, another individual sustained third-degree burns to his torso and upper extremities. In September 2012, the individual who received third-degree burns filed suit in New Jersey Superior Court, Salem County. In October 2012, additional suits were filed in the same court by or on behalf of the estates of the deceased individuals. Plaintiffs in each of the cases are seeking indeterminate damages and allege that ACE was negligent in the design, construction, erection, operation and maintenance of its poles, power lines, and equipment, and that ACE failed to warn and protect the public from the foreseeable dangers of farm equipment contacting electric lines. Discovery is ongoing in this matter and the litigation involves a number of other defendants and the filing of numerous cross-claims. ACE has notified its insurers of the incident and believes that the insurance policies in force at the time of the incident will offset ACE's costs associated with the resolution of this matter in excess of ACE's self-insured retention amount. At December 31, 2013, ACE has concluded that a loss is probable with respect to these claims and has recorded an estimated loss contingency liability, which is included in the liability for general litigation referred to above as of December 31, 2013. ACE has also concluded as of December 31, 2013 that realization of its insurance claims associated with this matter is probable and, accordingly, has recorded an estimated insurance receivable offsetting substantially all of the loss contingency liability in excess of ACE's self-insured retention amount.

Environmental Matters

ACE is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of ACE, environmental clean-up costs incurred by ACE generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of ACE described below at December 31, 2013 are summarized as follows:

	Legacy Generation - Regulated
	(millions of dollars)
Balance as of January 1	$ 1
Accruals	—
Payments	—
Balance as of December 31	1
Less amounts in Other Current Liabilities	—
Amounts in Other Deferred Credits	$ 1

Franklin Slag Pile Site

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

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

Ward Transformer Site

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

Contractual Obligations

Power Purchase Contracts

As of December 31, 2013, ACE's contractual obligations under non-derivative power purchase contracts were $214 million in 2014, $431 million in 2015 to 2016, $355 million in 2017 to 2018 and $1,086 million in 2019 and thereafter.

Lease Commitments

ACE leases certain types of property and equipment for use in its operations. Rental expense for operating leases was $12 million, $11 million and $10 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Total future minimum operating lease payments for ACE as of December 31, 2013 are $5 million in each of the years 2014 through 2016, $4 million in each of the years 2017 and 2018, and $29 million thereafter.

(14) 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 years ended December 31, 2013, 2012 and 2011 were $115 million, $117 million and $102 million, respectively.

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

	For the Year Ended December 31, 2013	2012	2011
	(millions of dollars)		
Meter reading services provided by Millennium Account Services LLC (an ACE affiliate)(a)	$ (4)	$ (4)	$ (4)
Intercompany use revenue (b)	3	3	2

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

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

	2013	2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (15)	$ (13)
Other	—	(1)
Total	$ (15)	$ (14)

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

During 2011, PHI, through Conectiv, LLC, made a $60 million capital contribution to ACE.

(15) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The quarterly data presented below reflect all adjustments necessary, in the opinion of management, for a fair presentation of the interim results. Quarterly data normally vary seasonally because of temperature variations and differences between summer and winter rates. Therefore, comparisons by quarter within a year are not meaningful.

	2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(millions of dollars)				
Total Operating Revenue	$ 277	$ 271	$ 396	$ 258	$1,202
Total Operating Expenses	254	242	341	229	1,066
Operating Income	23	29	55	29	136
Other Expenses	(17)	(18)	(17)	(15)	(67)
Income Before Income Tax Expense (Benefit)	6	11	38	14	69
Income Tax (Benefit) Expense	(3)	4	13	5	19
Net Income	$ 9	$ 7	$ 25	$ 9	$ 50

	2012 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(millions of dollars)				
Total Operating Revenue	$ 256	$ 270	$ 413	$ 259	$1,198
Total Operating Expenses	239	230	364	246	1,079
Operating Income	17	40	49	13	119
Other Expenses	(16)	(17)	(16)	(17)	(66)
Income (Loss) Before Income Tax Expense (Benefit)	1	23	33	(4)	53
Income Tax (Benefit) Expense	(1)	9	13	(3)	18
Net Income (Loss)	$ 2	$ 14	$ 20	$ (1)	$ 35

(16) VARIABLE INTEREST ENTITIES

ACE is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if ACE or a subsidiary is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. ACE performed a qualitative analysis to determine whether a variable interest provided a controlling financial interest in a VIE at December 31, 2013, which is described below.

ACE Power Purchase Agreements

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

Because ACE has no equity or debt invested in the NUGs, the maximum exposure to loss relates primarily to any above-market costs incurred for power. Due to unpredictability in the PPAs pricing for purchased energy, ACE is unable to quantify the maximum exposure to loss. The power purchase costs are recoverable from ACE's customers through regulated rates. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the years ended December 31, 2013, 2012 and 2011 were approximately $221 million, $206 million and $218 million, respectively, of which approximately $206 million, $201 million and $206 million, respectively, consisted of power purchases under the PPAs.

ACE Funding

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

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Pepco Holdings, Inc.

None.

Potomac Electric Power Company

None.

Delmarva Power & Light Company

None.

Atlantic City Electric Company

None.

Item 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Each Reporting Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in such Reporting Company's reports under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to management of such Reporting Company, including such Reporting Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), as appropriate, to allow timely decisions regarding required disclosure. This control system, no matter how well designed and operated, can provide only reasonable assurance that the objectives of the control system are met. Such Reporting Company's disclosure controls and procedures were designed to provide reasonable assurance of achieving their stated objectives. Under the supervision, and with the participation of management, including the CEO and the CFO, each Reporting Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2013, and, based upon this evaluation, the CEO and the CFO of such Reporting Company have concluded that these disclosure controls and procedures are effective to provide reasonable assurance that material information relating to such Reporting Company and its subsidiaries that is required to be disclosed in reports filed with, or submitted to, the SEC under the Exchange Act (i) is recorded, processed, summarized and reported within the time periods specified by the SEC rules and forms and (ii) is accumulated and communicated to management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" with respect to each Reporting Company.

Attestation Report of the Registered Public Accounting Firm

The "Report of Independent Registered Public Accounting Firm" with respect to the attestation report of PHI's registered public accounting firm is hereby incorporated by reference in response to this Item 9A.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted on July 21, 2010, exempts any company that is not a "large accelerated filer" or an "accelerated filer" (as defined by SEC rules) from the requirement that such company obtain an external audit of the effectiveness of its internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act. As a result, each of Pepco, DPL and ACE is exempt from the requirement that it include in its Annual Report on Form 10-K an attestation report on internal control over financial reporting by an independent registered public accounting firm; however, management's annual report on internal control over financial reporting, pursuant to Section 404(a) of the Sarbanes-Oxley Act, is still required with respect to each of them.

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 December 31, 2013, and has concluded there was no change in such Reporting Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, such Reporting Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

Pepco Holdings, Inc.

None.

Potomac Electric Power Company

None.

Delmarva Power & Light Company

None.

Atlantic City Electric Company

None.

Part III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Pepco Holdings, Inc.

Information required by this Item 10 is incorporated herein by reference to (1) PHI's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which is expected to be filed with the SEC no later than 120 days after December 31, 2013, and (2) the section entitled "Executive Officers of PHI" contained in Part I, Item 1. "Business," of this Form 10-K.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND THEREFORE ARE FILING THIS FORM WITH THE REDUCED FILING FORMAT.

Item 11. EXECUTIVE COMPENSATION

Pepco Holdings, Inc.

Information required by this Item 11 is incorporated herein by reference to PHI's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which is expected to be filed with the SEC no later than 120 days after December 31, 2013.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND THEREFORE ARE FILING THIS FORM WITH THE REDUCED FILING FORMAT.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Pepco Holdings, Inc.

Information required by this Item 12 is incorporated herein by reference to PHI's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which is expected to be filed with the SEC no later than 120 days after December 31, 2013.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND THEREFORE ARE FILING THIS FORM WITH THE REDUCED FILING FORMAT.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pepco Holdings, Inc.

Information required by this Item 13 is incorporated herein by reference to PHI's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which is expected to be filed with the SEC no later than 120 days after December 31, 2013.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND THEREFORE ARE FILING THIS FORM WITH THE REDUCED FILING FORMAT.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pepco Holdings, Pepco, DPL and ACE

Audit Fees

The aggregate fees billed by PricewaterhouseCoopers LLP for professional services rendered for the audit of the annual financial statements of Pepco Holdings and its subsidiary reporting companies for the 2013 and 2012 fiscal years, reviews of the financial statements included in the 2013 and 2012 Forms 10-Q of Pepco Holdings and its subsidiary reporting companies, reviews of other public filings, comfort letters and other attest services were $6,180,416 and $6,140,106, respectively. The amount for 2012 includes a reduction of $65,564 to reflect actual invoices received that were less than the estimated invoices included within the 2012 audit amount that was disclosed in Pepco Holdings' proxy statement for the 2013 Annual Meeting of Stockholders.

Audit-Related Fees

The aggregate fees billed by PricewaterhouseCoopers LLP for audit-related services rendered for the 2013 and 2012 fiscal years were $497,177 and zero, respectively. The 2013 fees consist of amounts billed in connection with advice and recommendations related to financial and accounting systems implementation, and for attest services performed in connection with public service commission rate case filings.

Tax Fees

The aggregate fees billed by PricewaterhouseCoopers LLP for tax services rendered for the 2013 and 2012 fiscal years were $1,292,685 and $644,012, respectively. These services generally consisted of tax compliance, tax advice and tax planning. In addition, the amount for the 2013 fiscal year included $560,236 in fees for assistance with issues related to the evaluation of potential settlement scenarios with respect to the former cross-border energy lease investments.

All Other Fees

The aggregate fees billed by PricewaterhouseCoopers LLP for all other services other than those covered under "Audit Fees," "Audit-Related Fees" and "Tax Fees" were $7,200 for each of the 2013 and 2012 fiscal years. These fees for 2013 and 2012 represented the costs of an online accounting and financial reporting research tool.

All of the services described in "Audit Fees," "Audit-Related Fees," "Tax Fees" and "All Other Fees" were approved in advance by the Audit Committee, in accordance with the Audit Committee Policy on the Approval of Services Provided By the Independent Auditor, which will be attached as Annex A to Pepco Holdings' definitive proxy statement for the 2014 Annual Meeting of Stockholders, which is expected to be filed with the SEC no later than 120 days after December 31, 2013, and is incorporated herein by reference.

Part IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents List

1. *Financial Statements*

Pepco Holdings, Inc.

Consolidated Statements of (Loss) Income for each of the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Comprehensive (Loss) Income for each of the years ended December 31, 2013, 2012 and 2011
Consolidated Balance Sheets as of December 31, 2013 and 2012
Consolidated Statements of Cash Flows for each of the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Equity for each of the years ended December 31, 2013, 2012 and 2011
Notes to Consolidated Financial Statements

Potomac Electric Power Company

Statements of Income for each of the years ended December 31, 2013, 2012 and 2011
Balance Sheets as of December 31, 2013 and 2012
Statements of Cash Flows for each of the years ended December 31, 2013, 2012 and 2011
Statements of Equity for each of the years ended December 31, 2013, 2012 and 2011
Notes to Financial Statements

Delmarva Power & Light Company

Statements of Income for each of the years ended December 31, 2013, 2012 and 2011
Balance Sheets as of December 31, 2013 and 2012
Statements of Cash Flows for each of the years ended December 31, 2013, 2012 and 2011
Statements of Equity for each of the years ended December 31, 2013, 2012 and 2011
Notes to Financial Statements

Atlantic City Electric Company

Consolidated Statements of Income for each of the years ended December 31, 2013, 2012 and 2011
Consolidated Balance Sheets as of December 31, 2013 and 2012
Consolidated Statements of Cash Flows for each of the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Equity for each of the years ended December 31, 2013, 2012 and 2011
Notes to Consolidated Financial Statements

2. *Financial Statement Schedules*

The financial statement schedules specified by Regulation S-X, other than those listed below, are omitted because either they are not applicable or the required information is presented in the financial statements included in Part II, Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

	Registrants			
Item	**Pepco Holdings**	**Pepco**	**DPL**	**ACE**
Schedule I, Condensed Financial Information of Parent Company	345	N/A	N/A	N/A
Schedule II, Valuation and Qualifying Accounts	352	352	353	353

Schedule I, Condensed Financial Information of Parent Company is submitted below.

PEPCO HOLDINGS, INC. (Parent Company)
STATEMENTS OF (LOSS) INCOME

	For the Year Ended December 31, 2013	2012	2011
	(millions of dollars, except share data)		
Operating Revenue	$ —	$ —	$ —
Operating Expenses			
Other operation and maintenance	1	1	1
Total operating expenses	1	1	1
Operating Loss	(1)	(1)	(1)
Other Income (Expenses)			
Interest expense	(42)	(33)	(29)
Income from equity investments	204	237	243
Impairment losses	—	—	(5)
Total other income	162	204	209
Income from Continuing Operations Before Income Tax	161	203	208
Income Tax Expense (Benefit) Related to Continuing Operations	51	(15)	(14)
Net Income from Continuing Operations	110	218	222
(Loss) Income from Discontinued Operations, net of Income Taxes	(322)	67	35
Net (Loss) Income	$ (212)	$ 285	$ 257
Comprehensive (Loss) Income	$ (198)	$ 300	$ 300
Earnings Per Share			
Basic earnings per share of common stock from Continuing Operations	$ 0.45	$ 0.95	$ 0.98
Basic (loss) earnings per share of common stock from Discontinued Operations	(1.31)	0.30	0.16
Basic (loss) earnings per share of common stock	$ (0.86)	$ 1.25	$ 1.14
Diluted earnings per share of common stock from Continuing Operations	$ 0.45	$ 0.95	$ 0.98
Diluted (loss) earnings per share of common stock from Discontinued Operations	(1.31)	0.29	0.16
Diluted (loss) earnings per share of common stock	$ (0.86)	$ 1.24	$ 1.14

The accompanying Notes are an integral part of these financial statements.

PEPCO HOLDINGS, INC. (Parent Company)
BALANCE SHEETS

	As of December 31,	
	2013	2012
	(millions of dollars, except share data)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ —	$ 262
Prepayments of income taxes	151	12
Accounts receivable and other	28	7
	179	281
Investments and Other Assets		
Goodwill	1,398	1,398
Investment in consolidated companies	3,935	2,633
Net assets associated with investment in consolidated companies held for disposition	—	1,232
Other	37	55
	5,370	5,318
Total Assets	$ 5,549	$ 5,599
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term debt	$ 24	$ 464
Interest and taxes accrued	10	11
Accounts payable due to associated companies	1	2
	35	477
Deferred Credits		
Notes payable due to subsidiary companies	491	—
Liabilities and accrued interest related to uncertain tax positions	3	3
	494	3
Long-Term Debt	705	705
Commitments and Contingencies (Note 4)		
Equity		
Common stock, $.01 par value; 400,000,000 shares authorized; 250,324,898 and 230,015,427 shares outstanding, respectively	3	2
Premium on stock and other capital contributions	3,751	3,383
Accumulated other comprehensive loss	(34)	(48)
Retained earnings	595	1,077
Total equity	4,315	4,414
Total Liabilities and Equity	$ 5,549	$ 5,599

The accompanying Notes are an integral part of these financial statements.

PEPCO HOLDINGS, INC. (Parent Company)
STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2013	2012	2011
		(millions of dollars)	
OPERATING ACTIVITIES			
Net (loss) income	$ (212)	$ 285	$ 257
Loss (income) from discontinued operations, net of income taxes	322	(67)	(35)
Adjustments to reconcile net income to net cash from operating activities:			
Distributions from related parties less than earnings	(127)	(52)	(169)
Deferred income taxes	(7)	(31)	(16)
Changes in:			
Prepaid and other	2	(23)	23
Accounts payable	6	6	2
Interest and taxes	(141)	39	42
Other assets and liabilities	3	4	11
Net Cash (Used By) From Operating Activities	(154)	161	115
FINANCING ACTIVITIES			
Dividends paid on common stock	(270)	(248)	(244)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	50	51	47
Issuances of common stock	324	—	—
Capital distribution to subsidiaries, net	(250)	(110)	(20)
Decrease in notes receivable from associated companies	—	154	—
Increase in notes payable due to associated companies	491	—	—
(Repayments) issuances of short-term debt, net	(240)	(201)	235
Issuance of term loan	250	200	—
Repayments of term loans	(450)	—	—
Costs of issuances	(13)	(2)	(7)
Net Cash (Used By) From Financing Activities	(108)	(156)	11
Net (decrease) increase in cash and cash equivalents	(262)	5	126
Cash and cash equivalents at beginning of year	262	257	131
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ —	$ 262	$ 257

The accompanying Notes are an integral part of these financial statements.

NOTES TO FINANCIAL INFORMATION

(1) BASIS OF PRESENTATION

Pepco Holdings, Inc. (Pepco Holdings) is a holding company and conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Pepco Holdings included in Part II, Item 8 of this Form 10-K.

Pepco Holdings owns 100% of the common stock of all its significant subsidiaries.

(2) RECLASSIFICATIONS AND ADJUSTMENTS

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

Revision to Prior Period Financial Statements

PCI Deferred Income Tax Liability Adjustment

Since 1999, PCI had not recorded a deferred tax liability related to a temporary difference between the financial reporting basis and the tax basis of an investment in a wholly owned partnership. In the second quarter of 2013, PHI re-evaluated this accounting treatment and found it to be in error, requiring an adjustment related to prior periods. PHI determined that the cumulative adjustment required, representing a charge to earnings of $32 million, related to a period prior to the year ended December 31, 2009 (the earliest period for which selected consolidated financial data were presented in the table entitled "Selected Financial Data" in Part II, Item 6 of this Annual Report on Form 10-K). Consistent with PHI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, the accompanying PHI parent company financial statements reflect the correction of this error as an adjustment to shareholders' equity for the earliest period presented. The adjustment to correct the error did not affect PHI's parent company statements of income and cash flows for each of the three years in the period ended December 31, 2013, and only affected the reported balances of investment in consolidated companies and retained earnings as reflected in PHI's parent company balance sheets as of December 31, 2013 and 2012. The adjustment is not considered to be material to the reported balances of retained earnings and total equity reflected in PHI's parent company financial statements included in this Annual Report on Form 10-K. The table below illustrates the effects of the revision on reported balances in PHI's parent company financial statements.

	As Filed	Adjustment (millions of dollars)	As Revised
December 31, 2012			
Investment in consolidated companies	$ 2,665(a)	$ (32)	$ 2,633
Total investments and other assets	5,350	(32)	5,318
Retained earnings	1,109	(32)	1,077
Total equity	4,446	(32)	4,414
December 31, 2011			
Investment in consolidated companies	$ 2,351(a)	$ (32)	$ 2,319
Total investments and other assets	5,230	(32)	5,198
Retained earnings	1,072	(32)	1,040
Total equity	4,336	(32)	4,304
December 31, 2010			
Investment in consolidated companies	$ 1,664	$ (32)	$ 1,632
Total investments and other assets	4,959	(32)	4,927
Retained earnings	1,059	(32)	1,027
Total equity	4,230	(32)	4,198

(a) The amount differs from the amount originally reported in the 2012 Form 10-K due to the reclassification of net assets associated with investment in consolidated companies to assets held for disposition.

(3) DEBT

For information concerning Pepco Holdings' long-term debt obligations, see Note (10), "Debt," to the consolidated financial statements of Pepco Holdings.

(4) COMMITMENTS AND CONTINGENCIES

For information concerning Pepco Holdings' material contingencies and guarantees, see Note (15), "Commitments and Contingencies" to the consolidated financial statements of Pepco Holdings.

Pepco Holdings guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting businesses and underground transmission and distribution construction business. At December 31, 2013, Pepco Holdings' guarantees of Pepco Energy Services' obligations under these contracts totaled $190 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects in these businesses. These guarantees totaled $229 million at December 31, 2013.

In addition, Pepco Holdings guarantees certain obligations of Pepco, DPL, and ACE under surety bonds obtained by these subsidiaries, for construction projects and self-insured workers compensation matters. These guarantees totaled $29 million at December 31, 2013.

Pepco Holdings, pursuant to an intercompany guarantee agreement with Potomac Capital Investment Corporation (PCI), guarantees certain intercompany obligations of PCI to its subsidiaries. This guarantee totaled $725 million at December 31, 2013.

(5) INVESTMENT IN CONSOLIDATED COMPANIES

Pepco Holdings' majority owned subsidiaries are recorded using the equity method of accounting. A breakout of the balance in Investment in consolidated companies is as follows:

	2013	2012
	(millions of dollars)	
Conectiv LLC	$1,730	$1,473
Potomac Electric Power Company	1,922	1,643
Potomac Capital Investment Corporation (a)	29	(729)
Pepco Energy Services, Inc.	250	242
PHI Service Company	4	4
Total investment in consolidated companies	$3,935	$2,633

(a) The investment in PCI excludes net assets held for disposition at December 31, 2012 and primarily represents income tax obligations related to the assets held for disposition.

(6) DISCONTINUED OPERATIONS

During the second and third quarters of 2013, PCI terminated all of its interests in its six remaining cross-border energy lease investments. PCI received aggregate net cash proceeds from these early terminations of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. As a result, PHI has reported the results of operations of the cross-border energy lease investments as discontinued operations in all periods presented in the accompanying statements of (loss) income. Further, the assets and liabilities related to the cross-border energy lease investments are reported as held for disposition as of each date in the accompanying balance sheets.

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

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 for $1.64 billion. The disposition 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.

(7) RELATED PARTY TRANSACTIONS

As of December 31, 2013 and 2012, PHI had the following balances on its balance sheets due (to) from related parties:

	2013	2012
	(millions of dollars)	
(Payable to) Receivable from Related Party (current) (a)		
Conectiv Communications, Inc.	$ (4)	$ (4)
PHI Service Company	3	1
Other	—	1
Total	$ (1)	$ (2)
Payable to Related Party (non-current) (b)		
Potomac Capital Investment Corporation	$ (491)	$ —
Money Pool Balance (included in cash and cash equivalents)	$ —	$ 262

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

Schedule II, Valuation and Qualifying Accounts, for each registrant is submitted below.

Pepco Holdings, Inc.

Col. A	Col. B	Col. C		Col. D	Col. E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions(b)	Balance at End of Period
		(millions of dollars)			
Year Ended December 31, 2013 Allowance for uncollectible accounts—customer and other accounts receivable	$ 34	$ 37	$ 5	$ (38)	$ 38
Year Ended December 31, 2012 Allowance for uncollectible accounts—customer and other accounts receivable	$ 43	$ 35	$ 8	$ (52)	$ 34
Year Ended December 31, 2011 Allowance for uncollectible accounts—customer and other accounts receivable	$ 44	$ 45	$ 8	$ (54)	$ 43

(a) Collection of accounts previously written off.
(b) Uncollectible accounts written off.

Potomac Electric Power Company

Col. A	Col. B	Col. C		Col. D	Col. E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions(b)	Balance at End of Period
		(millions of dollars)			
Year Ended December 31, 2013 Allowance for uncollectible accounts—customer and other accounts receivable	$ 13	$ 15	$ 1	$ (13)	$ 16
Year Ended December 31, 2012 Allowance for uncollectible accounts—customer and other accounts receivable	$ 18	$ 13	$ 2	$ (20)	$ 13
Year Ended December 31, 2011 Allowance for uncollectible accounts—customer and other accounts receivable	$ 20	$ 21	$ 2	$ (25)	$ 18

(a) Collection of accounts previously written off.
(b) Uncollectible accounts written off.

Delmarva Power & Light Company

Col. A Description	Col. B Balance at Beginning of Period	Col. C Additions: Charged to Costs and Expenses	Col. C Additions: Charged to Other Accounts (a)	Col. D Deductions(b)	Col. E Balance at End of Period
		(millions of dollars)			
Year Ended December 31, 2013 Allowance for uncollectible accounts—customer and other accounts receivable	$ 9	$ 11	$ 1	$ (9)	$ 12
Year Ended December 31, 2012 Allowance for uncollectible accounts—customer and other accounts receivable	$ 12	$ 11	$ 3	$ (17)	$ 9
Year Ended December 31, 2011 Allowance for uncollectible accounts—customer and other accounts receivable	$ 13	$ 11	$ 3	$ (15)	$ 12

(a) Collection of accounts previously written off.
(b) Uncollectible accounts written off.

Atlantic City Electric Company

Col. A Description	Col. B Balance at Beginning of Period	Col. C Additions: Charged to Costs and Expenses	Col. C Additions: Charged to Other Accounts (a)	Col. D Deductions(b)	Col. E Balance at End of Period
		(millions of dollars)			
Year Ended December 31, 2013 Allowance for uncollectible accounts—customer and other accounts receivable	$ 11	$ 11	$ 3	$ (15)	$ 10
Year Ended December 31, 2012 Allowance for uncollectible accounts—customer and other accounts receivable	$ 12	$ 12	$ 3	$ (16)	$ 11
Year Ended December 31, 2011 Allowance for uncollectible accounts—customer and other accounts receivable	$ 11	$ 13	$ 3	$ (15)	$ 12

(a) Collection of accounts previously written off.
(b) Uncollectible accounts written off.

3. EXHIBITS

The documents listed below are being filed or furnished on behalf of PHI, Pepco, DPL and/or ACE, as indicated. The warranties, representations and covenants contained in any of the agreements included or incorporated by reference herein or which appear as exhibits hereto should not be relied upon by buyers, sellers or holders of PHI's or its subsidiaries' securities and are not intended as warranties, representations or covenants to any individual or entity except as specifically set forth in such agreement.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
3.1	PHI	Restated Certificate of Incorporation (filed in Delaware 6/2/2005)	Exh. 3.1 to PHI's Form 10-K, 3/13/06.
3.2	Pepco	Restated Articles of Incorporation and Articles of Restatement (as filed in the District of Columbia)	Exh. 3.1 to Pepco's Form 10-Q, 5/5/06.
3.3	Pepco	Restated Articles of Incorporation and Articles of Restatement (as filed in Virginia)	Exh. 3.3 to PHI's Form 10-Q, 11/4/11.
3.4	DPL	Articles of Restatement of Certificate and Articles of Incorporation (filed in Delaware and Virginia 02/22/07)	Exh. 3.3 to DPL's Form 10-K, 3/1/07.
3.5	ACE	Restated Certificate of Incorporation (filed in New Jersey 8/09/02)	Exh. B.8.1 to PHI's Amendment No. 1 to Form U5B, 2/13/03.
3.6	PHI	Bylaws	Exh. 3.6 to PHI's Form 10-K, 2/28/13.
3.7	Pepco	Bylaws	Exh. 3.2 to Pepco's Form 10-Q, 5/5/06.
3.8	DPL	Bylaws	Exh. 3.2.1 to DPL's Form 10-Q, 5/9/05.
3.9	ACE	Bylaws	Exh. 3.2.2 to ACE's Form 10-Q, 5/9/05.
4.1	PHI Pepco	Mortgage and Deed of Trust dated July 1, 1936, of Pepco to The Bank of New York Mellon as successor trustee, securing First Mortgage Bonds of Pepco, and Supplemental Indenture dated July 1, 1936	Exh. B-4 to First Amendment, 6/19/36, to Pepco's Registration Statement No. 2-2232.
		Supplemental Indentures, to the aforesaid Mortgage and Deed of Trust, dated as of - December 10, 1939	Exh. B to Pepco's Form 8-K, 1/3/40.
		July 15, 1942	Exh. B-1 to Amendment No. 2, 8/24/42, and B-3 to Post-Effective Amendment, 8/31/42, to Pepco's Registration Statement No. 2-5032.
		October 15, 1947	Exh. A to Pepco's Form 8-K, 12/8/47.
		December 31, 1948	Exh. A-2 to Pepco's Form 10-K, 4/13/49.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		December 31, 1949	Exh. (a)-1 to Pepco's Form 8-K, 2/8/50.
		February 15, 1951	Exh. (a) to Pepco's Form 8-K, 3/9/51.
		February 16, 1953	Exh. (a)-1 to Pepco's Form 8-K, 3/5/53.
		March 15, 1954 and March 15, 1955	Exh. 4-B to Pepco's Registration Statement No. 2-11627, 5/2/55.
		March 15, 1956	Exh. C to Pepco's Form 10-K, 4/4/56.
		April 1, 1957	Exh. 4-B to Pepco's Registration Statement No. 2-13884, 2/5/58.
		May 1, 1958	Exh. 2-B to Pepco's Registration Statement No. 2-14518, 11/10/58.
		May 1, 1959	Exh. 4-B to Amendment No. 1, 5/13/59, to Pepco's Registration Statement No. 2-15027.
		May 2, 1960	Exh. 2-B to Pepco's Registration Statement No. 2-17286, 11/9/60.
		April 3, 1961	Exh. A-1 to Pepco's Form 10-K, 4/24/61.
		May 1, 1962	Exh. 2-B to Pepco's Registration Statement No. 2-21037, 1/25/63.
		May 1, 1963	Exh. 4-B to Pepco's Registration Statement No. 2-21961, 12/19/63.
		April 23, 1964	Exh. 2-B to Pepco's Registration Statement No. 2-22344, 4/24/64.
		May 3, 1965	Exh. 2-B to Pepco's Registration Statement No. 2-24655, 3/16/66.
		June 1, 1966	Exh. 1 to Pepco's Form 10-K, 4/11/67.
		April 28, 1967	Exh. 2-B to Post-Effective Amendment No. 1 to Pepco's Registration Statement No. 2-26356, 5/3/67.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		July 3, 1967	Exh. 2-B to Pepco's Registration Statement No. 2-28080, 1/25/68.
		May 1, 1968	Exh. 2-B to Pepco's Registration Statement No. 2-31896, 2/28/69.
		June 16, 1969	Exh. 2-B to Pepco's Registration Statement No. 2-36094, 1/27/70.
		May 15, 1970	Exh. 2-B to Pepco's Registration Statement No. 2-38038, 7/27/70.
		September 1, 1971	Exh. 2-C to Pepco's Registration Statement No. 2-45591, 9/1/72.
		June 17, 1981	Exh. 2 to Amendment No. 1 to Pepco's Form 8-A, 6/18/81.
		November 1, 1985	Exh. 2B to Pepco's Form 8-A, 11/1/85.
		September 16, 1987	Exh. 4-B to Pepco's Registration Statement No. 33-18229, 10/30/87.
		May 1, 1989	Exh. 4-C to Pepco's Registration Statement No. 33-29382, 6/16/89.
		May 21, 1991	Exh. 4 to Pepco's Form 10-K, 3/27/92.
		May 7, 1992	Exh. 4 to Pepco's Form 10-K, 3/26/93.
		September 1, 1992	Exh. 4 to Pepco's Form 10-K, 3/26/93.
		November 1, 1992	Exh. 4 to Pepco's Form 10-K, 3/26/93.
		July 1, 1993	Exh. 4.4 to Pepco's Registration Statement No. 33-49973, 8/11/93.
		February 10, 1994	Exh. 4 to Pepco's Form 10-K, 3/25/94.
		February 11, 1994	Exh. 4 to Pepco's Form 10-K, 3/25/94.
		October 2, 1997	Exh. 4 to Pepco's Form 10-K, 3/26/98.
		November 17, 2003	Exhibit 4.1 to Pepco's Form 10-K, 3/11/04.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		March 16, 2004	Exh. 4.3 to Pepco's Form 8-K, 3/23/04.
		May 24, 2005	Exh. 4.2 to Pepco's Form 8-K, 5/26/05.
		April 1, 2006	Exh. 4.1 to Pepco's Form 8-K, 4/17/06.
		November 13, 2007	Exh. 4.2 to Pepco's Form 8-K, 11/15/07.
		March 24, 2008	Exh. 4.1 to Pepco's Form 8-K, 3/28/08.
		December 3, 2008	Exh. 4.2 to Pepco's Form 8-K, 12/8/08.
		March 28, 2012	Exh. 4.2 to Pepco's Form 8-K, 3/29/12.
		March 11, 2013	Exh. 4.2 to Pepco's Form 8-K, 3/12/13.
		November 14, 2013	Exh. 4.2 to Pepco's Form 8-K, 11/15/13.
4.2	PHI Pepco	Indenture, dated as of July 28, 1989, between Pepco and The Bank of New York Mellon, Trustee, with respect to Pepco's Medium-Term Note Program	Exh. 4 to Pepco's Form 8-K, 6/21/90.
4.3	PHI Pepco	Senior Note Indenture dated November 17, 2003 between Pepco and The Bank of New York Mellon	Exh. 4.2 to Pepco's Form 8-K, 11/21/03.
		Supplemental Indenture, to the aforesaid Senior Note Indenture, dated March 3, 2008	Exh. 4.3 to Pepco's Form 10-K, 3/2/09.
4.4	PHI DPL	Mortgage and Deed of Trust of Delaware Power & Light Company to The Bank of New York Mellon (ultimate successor to the New York Trust Company), as trustee, dated as of October 1, 1943 and copies of the First through Sixty-Eighth Supplemental Indentures thereto	Exh. 4-A to DPL's Registration Statement No. 33-1763, 11/27/85.
		Sixty-Ninth Supplemental Indenture	Exh. 4-B to DPL's Registration Statement No. 33-39756, 4/03/91.
		Seventieth through Seventy-Fourth Supplemental Indentures	Exhs. 4-B to DPL's Registration Statement No. 33-24955, 10/13/88.
		Seventy-Fifth through Seventy-Seventh Supplemental Indentures	Exhs. 4-D, 4-E and 4-F to DPL's Registration Statement No. 33-39756, 4/03/91.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		Seventy-Eighth and Seventy-Ninth Supplemental Indentures	Exhs. 4-E and 4-F to DPL's Registration Statement No. 33-46892, 4/1/92.
		Eightieth Supplemental Indenture	Exh. 4 to DPL's Registration Statement No. 33-49750, 7/17/92.
		Eighty-First Supplemental Indenture	Exh. 4-G to DPL's Registration Statement No. 33-57652, 1/29/93.
		Eighty-Second Supplemental Indenture	Exh. 4-H to DPL's Registration Statement No. 33-63582, 5/28/93.
		Eighty-Third Supplemental Indenture	Exh. 99 to DPL's Registration Statement No. 33-50453, 10/1/93.
		Eighty-Fourth through Eighty-Eighth Supplemental Indentures	Exhs. 4-J, 4-K, 4-L, 4-M and 4-N to DPL's Registration Statement No. 33-53855, 1/30/95.
		Eighty-Ninth and Ninetieth Supplemental Indentures	Exhs. 4-K and 4-L to DPL's Registration Statement No. 333-00505, 1/29/96.
		Ninety-First Supplemental Indenture	Exh. 4.L to DPL's Registration Statement No. 333-24059, 3/27/97.
		Ninety-Second Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		Ninety-Third Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		Ninety-Fourth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		Ninety-Fifth Supplemental Indenture	Exh. 4-K to DPL's Post Effective Amendment No. 1 to Registration Statement No. 333-145691-02, 11/18/08.
		Ninety-Sixth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		Ninety-Seventh Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		Ninety-Eighth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		Ninety-Ninth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		One Hundredth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		One Hundred and First Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		One Hundred and Second Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		One Hundred and Third Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		One Hundred and Fourth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/24/12.
		One Hundred and Fifth Supplemental Indenture	Exh. 4.4 to DPL's Form 8-K, 10/1/09.
		One Hundred and Sixth Supplemental Indenture	Exh. 4.4 to DPL's Form 10-K, 2/25/11.
		One Hundred and Seventh Supplemental Indenture	Exh. 4.2 to DPL's Form 10-Q, 8/3/11.
		One Hundred and Eighth Supplemental Indenture	Exh. 4.2 to DPL's Form 8-K, 6/3/11.
		One Hundred and Ninth Supplemental Indenture	Exh. 4.3 to DPL's Form 10-Q, 8/7/12.
		One Hundred and Tenth Supplemental Indenture	Exh. 4.2 to DPL's Form 8-K, 6/20/12.
		One Hundred and Eleventh Supplemental Indenture	Exh. 4.1 to DPL's Form 10-Q, 8/6/13.
		One Hundred and Twelfth Supplemental Indenture	Exh. 4.2 to DPL's Form 8-K, 11/8/13.
4.5	PHI DPL	Indenture between DPL and The Bank of New York Mellon Trust Company, N.A. (ultimate successor to Manufacturers Hanover Trust Company), as trustee, dated as of November 1, 1988	Exh. No. 4-G to DPL's Registration Statement No. 33-46892, 4/1/92.
4.6	PHI ACE	Mortgage and Deed of Trust, dated January 15, 1937, between ACE and The Bank of New York Mellon (formerly Irving Trust Company), as trustee	Exh. 2(a) to ACE's Registration Statement No. 2-66280, 12/21/79.
		Supplemental Indentures, to the aforesaid Mortgage and Deed of Trust, dated as of -	
		June 1, 1949	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		July 1, 1950	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		November 1, 1950	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		March 1, 1952	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		January 1, 1953	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		March 1, 1954	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		March 1, 1955	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		January 1, 1957	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		April 1, 1958	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		April 1, 1959	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		March 1, 1961	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		July 1, 1962	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		March 1, 1963	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		February 1, 1966	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		April 1, 1970	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		September 1, 1970	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		May 1, 1971	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		April 1, 1972	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		June 1, 1973	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		January 1, 1975	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		May 1, 1975	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		December 1, 1976	Exh. 2(b) to ACE's Registration Statement No. 2-66280, 12/21/79.
		January 1, 1980	Exh. 4(e) to ACE's Form 10-K, 3/25/81.
		May 1, 1981	Exh. 4(a) to ACE's Form 10-Q, 8/10/81.
		November 1, 1983	Exh. 4(d) to ACE's Form 10-K, 3/30/84.
		April 15, 1984	Exh. 4(a) to ACE's Form 10-Q, 5/14/84.
		July 15, 1984	Exh. 4(a) to ACE's Form 10-Q, 8/13/84.
		October 1, 1985	Exh. 4 to ACE's Form 10-Q, 11/12/85.
		May 1, 1986	Exh. 4 to ACE's Form 10-Q, 5/12/86.
		July 15, 1987	Exh. 4(d) to ACE's Form 10-K, 3/28/88.
		October 1, 1989	Exh. 4(a) to ACE's Form 10-Q for quarter ended 9/30/89.
		March 1, 1991	Exh. 4(d)(1) to ACE's Form 10-K, 3/28/91.
		May 1, 1992	Exh. 4(b) to ACE's Registration Statement No. 33-49279, 1/6/93.
		January 1, 1993	Exh. 4.05(hh) to ACE's Registration Statement No. 333-108861, 9/17/03.
		August 1, 1993	Exh. 4(a) to ACE's Form 10-Q, 11/12/93.
		September 1, 1993	Exh. 4(b) to ACE's Form 10-Q, 11/12/93.
		November 1, 1993	Exh. 4(c)(1) to ACE's Form 10-K, 3/29/94.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
		June 1, 1994	Exh. 4(a) to ACE's Form 10-Q, 8/14/94.
		October 1, 1994	Exh. 4(a) to ACE's Form 10-Q, 11/14/94.
		November 1, 1994	Exh. 4(c)(1) to ACE's Form 10-K, 3/21/95.
		March 1, 1997	Exh. 4(b) to ACE's Form 8-K, 3/24/97.
		April 1, 2004	Exh. 4.3 to ACE's Form 8-K, 4/6/04.
		August 10, 2004	Exh. 4 to PHI's Form 10-Q, 11/8/04.
		March 8, 2006	Exh. 4 to ACE's Form 8-K, 3/17/06.
		November 6, 2008	Exh. 4.2 to ACE's Form 8-K, 11/10/08.
		March 29, 2011	Exh. 4.2 to ACE's Form 8-K, 4/1/11.
4.7	PHI ACE	Indenture dated as of March 1, 1997 between ACE and The Bank of New York Mellon, as trustee	Exh. 4(e) to ACE's Form 8-K, 3/24/97.
4.8	PHI ACE	Senior Note Indenture, dated as of April 1, 2004, with The Bank of New York Mellon, as trustee	Exh. 4.2 to ACE's Form 8-K, 4/6/04.
4.9	PHI ACE	Indenture dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC (ACE Funding) and The Bank of New York Mellon, as trustee	Exh. 4.1 to ACE Funding's Form 8-K, 12/23/02.
4.10	PHI ACE	2002-1 Series Supplement dated as of December 19, 2002 between ACE Funding and The Bank of New York Mellon, as trustee	Exh. 4.2 to ACE Funding's Form 8-K, 12/23/02.
4.11	PHI ACE	2003-1 Series Supplement dated as of December 23, 2003 between ACE Funding and The Bank of New York Mellon, as trustee	Exh. 4.2 to ACE Funding's Form 8-K, 12/23/03.
4.12	PHI	Indenture between PHI and The Bank of New York Mellon, as trustee dated September 6, 2002	Exh. 4.03 to PHI's Registration Statement No. 333-100478, 10/10/02.
4.13	PHI Pepco DPL ACE	Corporate Commercial Paper – Master Note	Exh. 4.13 to PHI's Form 10-K, 2/24/12.
10.1	ACE	Bondable Transition Property Sale Agreement between ACE Funding and ACE dated as of December 19, 2002	Exh. 10.1 to ACE Funding's Form 8-K, 12/23/02.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
10.2	ACE	Bondable Transition Property Servicing Agreement between ACE Funding and ACE dated as of December 19, 2002	Exh. 10.2 to ACE Funding's Form 8-K, 12/23/02.
10.3	PHI	Purchase Agreement, dated as of April 20, 2010, by and among PHI, Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC	Exh. 2.1 to PHI's Form 8-K, 7/8/10.
10.4	Pepco	Purchase Agreement, dated November 14, 2013, among Pepco and Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Scotia Capital (USA) Inc., as representatives of the several Underwriters named therein	Exh. 1.1 to Pepco's Form 8-K, 11/15/13.
10.5	DPL	Purchase Agreement, dated November 7, 2013, among DPL and Citigroup Global Markets Inc., RBS Securities Inc., and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein	Exh. 1.1 to DPL's Form 8-K, 11/8/13.
10.6	ACE	$100,000,000 Term Loan Agreement by and among ACE, KeyBank National Association, as Administrative Agent, SunTrust Bank, as Documentation Agent, and the Lenders Party Thereto, dated May 10, 2013	Exh. 10 to ACE's Form 8-K, 5/10/13.
10.7	PHI	$250,000,000 Term Loan Agreement by and among PHI, JPMorgan Chase Bank, N.A., as Administrative Agent, The Bank of Nova Scotia, as Documentation Agent, and the Lenders Party Thereto, dated March 28, 2013	Exh. 10 to PHI's Form 8-K, 3/28/13.
10.8	Pepco	Purchase Agreement, dated March 11, 2013, among Pepco and Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Scotia Capital (USA) Inc., as representatives of the several Underwriters named therein	Exh. 1.1 to Pepco's Form 8-K, 3/12/13.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
10.9	PHI Pepco DPL ACE	Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among PHI, Pepco, DPL and ACE, the lenders party thereto, Wells Fargo Bank, National Association, as agent, issuer and swingline lender, Bank of America, N.A., as syndication agent and issuer, The Royal Bank of Scotland plc and Citicorp USA, Inc., as co-documentation agents, Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner and Smith Incorporated, as active joint lead arrangers and joint book runners, and Citigroup Global Markets Inc. and RBS Securities, Inc. as passive joint lead arrangers and joint book runners	Exh. 10.1 to PHI's Form 10-Q, 8/3/11.
10.9.1	PHI Pepco DPL ACE	First Amendment dated as of August 2, 2012 to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among PHI, Pepco, DPL and ACE, the various financial institutions party thereto, Wells Fargo Bank, National Association, as agent, issuer of letters of credit and swingline lender, Bank of America, N.A., as syndication agent and issuer of letters of credit, and The Royal Bank of Scotland plc and Citibank, N.A., as co-documentation agents	Exh. 10.25.1 to PHI's Form 10-K, 2/28/13.
10.10	DPL	Purchase Agreement, dated June 19, 2012, among DPL and J.P. Morgan Securities LLC, Credit Suisse Securities (USA) LLC and SunTrust Robinson Humphrey Inc., as representatives of the several Underwriters named therein	Exh. 1.1 to DPL's Form 8-K, 6/20/12.
10.11	PHI	$200,000,000 Term Loan Agreement by and among PHI, JPMorgan Chase Bank, N.A., as Administrative Agent, The Bank of Nova Scotia, as Documentation Agent, and the Lenders Party Thereto, dated April 24, 2012	Exh. 10 to PHI's Form 8-K, 4/25/12.
10.12	Pepco	Purchase Agreement, dated March 28, 2012, among Pepco and Wells Fargo Securities, LLC, KeyBanc Capital Markets Inc. and RBS Securities Inc., as representatives of the several Underwriters named therein	Exh. 1.1 to Pepco's Form 8-K, 3/29/12.
10.13	PHI	Confirmation of Forward Sale Transaction dated March 5, 2012, by and between PHI and Morgan Stanley & Co. LLC	Exh. 10.1 to PHI's Form 8-K, 3/8/12.
10.13.1	PHI	Confirmation of Additional Forward Sale Transaction dated March 6, 2012 between PHI and Morgan Stanley & Co. LLC	Exh. 10.2 to PHI's Form 8-K, 3/8/12.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
10.14	PHI	Purchase Agreement, dated March 5, 2012, among PHI, Morgan Stanley & Co. LLC, J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Citigroup Global Markets Inc., individually and acting as representatives of each of the other underwriters named in Schedule A thereto, and Morgan Stanley & Co. LLC, as forward counterparty.	Exh. 1.1 to PHI's Form 8-K, 3/8/12.
10.15	DPL	Reoffering Agreement, dated May 18, 2011, by and among DPL and Morgan Stanley & Co. Incorporated, as remarketing agent, and Morgan Stanley & Co. Incorporated, as underwriter	Exh. 1.1 to DPL's Form 8-K, 6/3/11.
10.16	PHI Pepco DPL ACE	Form of Issuing and Paying Agency Agreement between JPMorgan Chase Bank, National Association, and each Reporting Company	Exh. 10.41 to PHI's Form 10-K, 2/24/12.
10.16.1	PHI Pepco DPL ACE	Amendment to Form of Issuing and Paying Agency Agreement	Exh. 10.41.1 to PHI's Form 10-K, 2/24/12.
10.17	PHI	Employment Agreement of Joseph M. Rigby dated December 20, 2011 (including forms of Restricted Stock Unit Award Agreements contained therein)*	Exh. 10 to PHI's Form 8-K, 12/27/11.
10.17.1	PHI	Amendment to the 2013 Performance-Based Restricted Stock Unit Award Agreement, effective as of October 25, 2013*	Exh. 10.2 to PHI's Form 8-K, 10/25/13.
10.18	PHI	Letter Agreement between Pepco Holdings, Inc. and Frederick J. Boyle*	Exh. 10 to PHI's Form 8-K, 3/26/12.
10.19	PHI	Employment Agreement, dated September 7, 2012, by and between PHI and Kevin C. Fitzgerald (including forms of Restricted Stock Award Agreements contained therein)*	Exh. 10.1 to PHI's Form 10-Q, 11/6/12.
10.20	PHI	Retirement Agreement, dated as of September 6, 2012, by and between PHI and Kirk J. Emge*	Exh. 10 to PHI's Form 8-K, 9/7/12.
10.21	PHI	Pepco Holdings, Inc. Amended and Restated Annual Executive Incentive Compensation Plan*	Exh. 10.30.1 to PHI's Form 10-K, 2/24/12.
10.22	PHI	Pepco Holdings, Inc. Long-Term Incentive Plan (as amended and restated)*	Exh. 10.5 to PHI's Form 10-K, 3/2/09.
10.22.1	PHI	Amendment to the Pepco Holdings, Inc. Long-Term Incentive Plan*	Exh. 10.2.1 to PHI's Form 10-K, 2/24/12.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
10.23	PHI	Form of 2012 Restricted Stock Unit Agreement (Time Based) under the PHI Long-Term Incentive Plan*	Exh. 10.36 to PHI's Form 10-K, 2/24/12.
10.24	PHI	Form of 2012 Restricted Stock Unit Agreement (Performance Based) under the PHI Long-Term Incentive Plan*	Exh. 10.37 to PHI's Form 10-K, 2/24/12.
10.25	PHI	Form of 2012 Restricted Stock Unit Agreement (Performance Based/162(m)) under the PHI Long-Term Incentive Plan*	Exh. 10.38 to PHI's Form 10-K, 2/24/12.
10.26	PHI	Pepco Holdings, Inc. 2012 Long-Term Incentive Plan*	Exh. 10.10 to PHI's Form 10-K, 2/28/13.
10.27	PHI	Form of Restricted Stock Unit Agreement (Director Award) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.4 to PHI's Form 10-Q, 8/7/12.
10.28	PHI	Form of 2012 Restricted Stock Unit Agreement (Time-Vested) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.3 to PHI's Form 8-K, 5/18/12.
10.29	PHI	Form of 2012 Restricted Stock Unit Agreement (Performance-Based/162(m)) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.4 to PHI's Form 8-K, 5/18/12.
10.30	PHI	Form of 2012 Restricted Stock Unit Agreement (Performance-Based/Non-162(m)) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.5 to PHI's Form 8-K, 5/18/12.
10.31	PHI	Form of Restricted Stock Unit Agreement (Time-Vested) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.50 to PHI's Form 10-K, 2/28/13.
10.32	PHI	Form of Restricted Stock Unit Agreement (Time-Vested) under the PHI 2012 Long-Term Incentive Plan for Joseph M. Rigby*	Exh. 10.3 to PHI's Form 10-Q, 5/2/13.
10.33	PHI	Form of Restricted Stock Unit Agreement (Time-Vested) under the PHI 2012 Long-Term Incentive Plan for Kevin C. Fitzgerald*	Exh. 10.4 to PHI's Form 10-Q, 5/2/13.
10.34	PHI	Form of Restricted Stock Unit Agreement (Performance-Based/162(m)) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.51 to PHI's Form 10-K, 2/28/13.
10.35	PHI	Form of Restricted Stock Unit Agreement (Performance Based/162(m)) under the PHI 2012 Long-Term Incentive Plan for Joseph M. Rigby*	Exh. 10.8 to PHI's Form 10-Q, 5/2/13.
10.36	PHI	Form of Restricted Stock Unit Agreement (Performance Based/162(m)) under the PHI 2012 Long-Term Incentive Plan for Kevin C. Fitzgerald*	Exh. 10.9 to PHI's Form 10-Q, 5/2/13.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
10.37	PHI	Form of Restricted Stock Unit Agreement (Performance-Based/Non-162(m)) under the PHI 2012 Long-Term Incentive Plan*	Exh. 10.52 to PHI's Form 10-K, 2/28/13.
10.38	PHI	Pepco Holdings, Inc. Second Revised and Restated Executive and Director Deferred Compensation Plan*	Exh. 10.31.1 to PHI's Form 10-K, 2/24/12.
10.39	PHI Pepco	Potomac Electric Power Company Director and Executive Deferred Compensation Plan*	Exh. 10.22 to PHI's Form 10-K, 3/28/03.
10.40	PHI	Conectiv Deferred Compensation Plan*	Exh. 10.1 to PHI's Form 10-Q, 8/6/04.
10.41	PHI	Form of 2013 Non-Management Director Compensation Election Agreement*	Exh. 10.32 to PHI's Form 10-K, 2/28/13.
10.42	PHI	Form of 2014 Non-Management Director Compensation Election Agreement*	Filed herewith.
10.43	PHI	Form of 2014 Executive and Director Deferred Compensation Plan Executive Deferral Agreement*	Filed herewith.
10.44	PHI	Non-Management Directors Compensation Plan*	Exh. 10.21 to PHI's Form 10-K, 3/2/09.
10.45	PHI	Non-Management Director Compensation Arrangements*	Exh. 10.13 to PHI's Form 10-K, 2/28/13.
10.46	PHI Pepco	Change-in-Control Severance Plan for Certain Executive Employees*	Exh. 10.25 to PHI's Form 10-K, 3/2/09.
10.46.1	PHI Pepco	Amended and Restated Change in Control / Severance Plan for Certain Executive Employees*	Exh. 10 to PHI's Form 8-K, 7/31/13.
10.47	PHI	Pepco Holdings, Inc. Combined Executive Retirement Plan*	Exh. 10.28 to PHI's Form 10-K, 3/2/09.
10.47.1	PHI	Amendment to the Pepco Holdings, Inc. Combined Executive Retirement Plan*	Exh. 10.3 to PHI's Form 10-Q, 8/3/11.
10.48	PHI	The Pepco Holdings, Inc. 2011 Supplemental Executive Retirement Plan*	Exh. 10.2 to PHI's Form 10-Q, 8/3/11.
10.49	PHI	Conectiv Supplemental Executive Retirement Plan*	Exh. 10.10 to PHI's Form 10-K, 3/2/09.
10.49.1	DPL	Amendment to the Conectiv Supplemental Executive Retirement Plan*	Exh. 10.4 to PHI's Form 10-Q, 8/3/11.
10.50	PHI	PHI Named Executive Officer 2013 Compensation Determinations*	Exh. 10.40 to PHI's Form 10-K, 2/28/13.
10.51	PHI	PHI Named Executive Officer 2014 Compensation Determinations*	Filed herewith.
10.52	PHI	Form of Election with Respect to Stock Tax Withholding*	Filed herewith.
11	PHI	Statements Re: Computation of Earnings Per Common Share	**

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
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.
21	PHI	Subsidiaries of the Registrant	Filed herewith.
23.1	PHI	Consent of Independent Registered Public Accounting Firm	Filed herewith.
23.2	Pepco	Consent of Independent Registered Public Accounting Firm	Filed herewith.
23.3	DPL	Consent of Independent Registered Public Accounting Firm	Filed herewith.
23.4	ACE	Consent of Independent Registered Public Accounting Firm	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.
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.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
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.

* Management contract or compensatory plan or arrangement.

** The information required by this Exhibit is set forth in Note (12), "Stock-Based Compensation, Dividend Restrictions and Calculations of Earnings Per Share of Common Stock," of the consolidated financial statements of Pepco Holdings, Inc. included in Part II, Item 8 "Financial Statements and Supplementary Data" of this Form 10-K.

Regulation S-K Item 10(d) requires registrants to identify the physical location, by SEC file number reference, of all documents incorporated by reference that are not included in a registration statement and have been on file with the SEC for more than five years. The SEC file number references for PHI, those of its subsidiaries that are currently registrants, Conectiv and ACE Funding 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)
Conectiv (File No. 001-13895)
Atlantic City Electric Transition Funding LLC (File No. 333-59558)

Certain instruments defining the rights of the holders of long-term debt of PHI, Pepco, DPL and ACE (including medium-term notes, unsecured notes, senior notes and tax-exempt financing instruments) have not been filed as exhibits in accordance with Regulation S-K Item 601(b)(4)(iii) because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis. Each of PHI, Pepco, DPL or ACE agrees to furnish to the SEC upon request a copy of any such instruments omitted by it.

INDEX TO FURNISHED EXHIBITS

The documents listed below are being 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

(b) Exhibits.

The list of exhibits filed or furnished with this Form 10-K are set forth on the exhibit index appearing at the end of this Form 10-K.

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.
(Registrant)

February 27, 2014

By /s/ JOSEPH M. RIGBY
Joseph M. Rigby
Chairman of the Board, President and
Chief Executive Officer

POTOMAC ELECTRIC POWER COMPANY (Pepco)
(Registrant)

February 27, 2014

By /s/ DAVID M. VELAZQUEZ
David M. Velazquez,
President and Chief
Executive Officer

DELMARVA POWER & LIGHT COMPANY (DPL)
(Registrant)

February 27, 2014

By /s/ DAVID M. VELAZQUEZ
David M. Velazquez,
President and Chief
Executive Officer

ATLANTIC CITY ELECTRIC COMPANY (ACE)
(Registrant)

February 27, 2014

By /s/ DAVID M. VELAZQUEZ
David M. Velazquez,
President and Chief
Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the above named registrants and in the capacities and on the dates indicated:

/s/ JOSEPH M. RIGBY Joseph M. Rigby	Chairman of the Board, President and Chief Executive Officer of Pepco Holdings, Director of Pepco, DPL and ACE **(Principal Executive Officer of Pepco Holdings)**	February 27, 2014
/s/ DAVID M. VELAZQUEZ David M. Velazquez	President and Chief Executive Officer of Pepco, DPL and ACE, Director of Pepco and DPL **(Principal Executive Officer of Pepco, DPL and ACE)**	February 27, 2014
/s/ FRED BOYLE Frederick J. Boyle	Senior Vice President and Chief Financial Officer of Pepco Holdings, Pepco, and DPL, Chief Financial Officer of ACE and Director of Pepco **(Principal Financial Officer of Pepco Holdings, Pepco, DPL and ACE)**	February 27, 2014
/s/ RONALD K. CLARK Ronald K. Clark	Vice President and Controller of Pepco Holdings, Pepco and DPL and Controller of ACE **(Principal Accounting Officer of Pepco Holdings, Pepco, DPL and ACE)**	February 27, 2014

Signature	Title	Date
/s/ PAUL M. BARBAS Paul M. Barbas	Director, Pepco Holdings	February 27, 2014
/s/ J.B. DUNN Jack B. Dunn, IV	Director, Pepco Holdings	February 27, 2014
/s/ H. RUSSELL FRISBY, JR. H. Russell Frisby, Jr.	Director, Pepco Holdings	February 27, 2014
/s/ T. C. GOLDEN Terence C. Golden	Director, Pepco Holdings	February 27, 2014
/s/ PATRICK T. HARKER Patrick T. Harker	Director, Pepco Holdings	February 27, 2014
/s/ FRANK O. HEINTZ Frank O. Heintz	Director, Pepco Holdings	February 27, 2014
/s/ BARBARA J. KRUMSIEK Barbara J. Krumsiek	Director, Pepco Holdings	February 27, 2014
/s/ GEORGE F. MacCORMACK George F. MacCormack	Director, Pepco Holdings	February 27, 2014
/s/ LAWRENCE C. NUSSDORF Lawrence C. Nussdorf	Director, Pepco Holdings	February 27, 2014
/s/ PATRICIA A. OELRICH Patricia A. Oelrich	Director, Pepco Holdings	February 27, 2014
/s/ FRANK ROSS Frank K. Ross	Director, Pepco Holdings	February 27, 2014
/s/ PAULINE A. SCHNEIDER Pauline A. Schneider	Director, Pepco Holdings	February 27, 2014
/s/ LESTER P. SILVERMAN Lester P. Silverman	Director, Pepco Holdings	February 27, 2014
/s/ KEVIN C. FITZGERALD Kevin C. Fitzgerald	Director, Pepco and DPL	February 27, 2014
/s/ CHARLES R. DICKERSON Charles R. Dickerson	Director, Pepco	February 27, 2014

/s/ WILLIAM M. GAUSMAN William M. Gausman	Director, Pepco	February 27, 2014
/s/ MICHAEL J. SULLIVAN Michael J. Sullivan	Director, Pepco	February 27, 2014

INDEX TO EXHIBITS FILED HEREWITH

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12.2	Pepco	Statements Re: Computation of Ratios
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31.6	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer
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101. SCH	PHI Pepco DPL ACE	XBRL Taxonomy Extension Schema Document
101. CAL	PHI Pepco DPL ACE	XBRL Taxonomy Extension Calculation Linkbase Document
101. DEF	PHI Pepco DPL ACE	XBRL Taxonomy Extension Definition Linkbase Document

101. LAB	PHI Pepco DPL ACE	XBRL Taxonomy Extension Label Linkbase Document
101. PRE	PHI Pepco DPL ACE	XBRL Taxonomy Extension Presentation Linkbase Document

* Management contract or compensatory plan or arrangement.

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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 10.42

Pepco Holdings, Inc.

2014 NON-MANAGEMENT DIRECTOR COMPENSATION ELECTION AGREEMENT

I understand that I am permitted to elect, with respect to the compensation due me for my services as a director of the Company, either (i) to receive my cash compensation currently in the form of either, or a combination of, cash and shares of Company common stock ("Common Stock") pursuant to the Non-Management Director Compensation Plan or (ii) to defer the receipt of my cash compensation under the terms of the Company's Second Revised and Restated Executive and Director Deferred Compensation Plan (the "Deferred Compensation Plan"). In addition, I understand that I am permitted to elect to receive my stock-based compensation granted pursuant to the terms of the 2012 Long-Term Incentive Plan (the "2012 LTIP"), or to defer the settlement of such stock-based compensation as permitted by the 2012 LTIP pursuant to a deferral program approved by the Board of Directors. If I choose to defer the receipt of my cash compensation, I must also complete and return to the Company the attached Cash Retainer Deferral Allocation Form directing how the deferred funds are to be credited.

I am making the following election with the understanding that the elections (i) will apply to all of the compensation paid to me for service as a director in 2014, (ii) once made, cannot be altered or revoked, and (ii) apply to all such compensation paid to me in subsequent years for services as a director, unless I notify the Company of any changes, either in writing or by execution of a new election form prior to January 1 of the year for which the changes are to take effect.

1. **Current Receipt or Deferral Election.**

I hereby elect to receive my compensation for services as a director of the Company as follows (the percentages for each type of compensation must total 100%):

a. **Annual Cash Retainer**

______% Cash (by check or direct deposit).

______% Common Stock (registered as indicated in Item 4 below).

______% Credit to my account under the Deferred Compensation Plan, to be paid in cash at the time I elect in Item 2 below.

b. **Retainer Paid in Form of Restricted Stock Units ("RSUs")**

I will receive an annual stock-based retainer award in the form of RSUs (and any associated dividend equivalents) under the 2012 LTIP, to be settled in Common Stock as indicated below:

______% Common Stock (registered as indicated herein) to be received upon settlement of the RSUs (and any associated dividend equivalents), shall be issued to me upon vesting of the RSUs as provided in the award agreement.

______% Common Stock (registered as indicated herein) to be received upon settlement of the RSUs (and any associated dividend equivalents), shall be deferred under the 2012 LTIP and paid in Common Stock at the time I elect in Item 3 below.

c. **Meeting Fees**

______% Cash (by check or direct deposit).

______% Common Stock (registered as indicated in Item 4 below).

______% Credit to my account under the Deferred Compensation Plan, to be paid in cash at the time I elect in Item 2 below.

d. **Committee Chairman Retainer** (please complete whether or not you currently are a committee chairman):

______% Cash (by check or direct deposit).

______% Common Stock (registered as indicated in Item 4 below).

______% Credit to my account under the Deferred Compensation Plan, to be paid in cash at the time I elect in Item 2 below.

2. **Cash Deferral Instructions.**

If you have elected to have all or any portion of your cash retainer(s) or meeting fees credited to your account under the Deferred Compensation Plan, please complete the following:

a. **Payment Instructions Related to Cash Amounts Deferred**

I hereby elect to have the cash amounts I have deferred under the Deferred Compensation Plan (and accruals thereon) paid to me beginning on the date selected below (check one):

______ On the first day of the month immediately following the month in which I cease to be a director.

______ On January 31 of the year immediately following the month in which I cease to be a director.

______ On January 31 of the year following the calendar year in which (i) I cease to be a director or (ii) I attain the age __, whichever is later.

______ On January 31 of ______ [insert year] or, if later, January 31 of the second calendar year following the calendar year which includes the first day of the Plan year for which the election is made.

b. **Manner of Payment**

I hereby elect to have the cash amounts I have deferred under the Deferred Compensation Plan (and accruals thereon) paid to me in the following manner (check one):

______ In a lump sum on the date of payment selected above.

______ In equal annual installments over __________ consecutive years [insert a number of years between 2 and 15] beginning on the date selected above, with subsequent installments to be paid on each succeeding January 31.

______ In equal monthly installments over __________ consecutive months [insert a number of months between 24 and 180] beginning on the date selected above.

3. **Stock-Based Award Deferral Instructions**

If I have elected to defer the settlement of my RSU award (and any associated dividend equivalents) under Item 1.b. above, I hereby elect payment to me (or, if applicable, my beneficiary) in a lump sum solely in shares of Common Stock on one of the dates I designate below (but only to the extent that such award has vested):

______ On the date I cease to be a director of the Company.

______ On the January 31 following the date I cease to be a director.

______ On a specified date (which may not be prior to January 31, 2017):

____

More information on the deferral of Stock-Based Awards under the 2012 Long-Term Incentive Plan is provided in Item 6 below.

4. **Registration of Stock Certificates.**

With respect to any shares of Common Stock that may be issued (a) upon settlement of an RSU (and any associated dividend equivalents) granted to me under the 2012 LTIP, whether or not deferred under Item 1.b above, or (b) in payment of any portion of my retainer or meeting fees, please register the stock certificates for those shares in the name set forth below, and provide a mailing or street address for such person:

____

____

____

____

5. **Beneficiary Designation.**

I designate the following Beneficiary (or Beneficiaries) to receive any benefits due under the Deferred Compensation Plan and/or the 2012 LTIP in the event of my death (specify full name, relationship and address):

Primary: ____________________________________

____

____

____

Contingent: ____________________________________

____

____

____

6. **Material Terms Related to My Deferral of an Annual Stock-Based Retainer Award.**

If I have elected in Item 1.b. above to defer settlement of my annual stock-based retainer award (and any associated dividend equivalents), I hereby acknowledge and agree that such deferral shall be subject to the following material terms, which have been approved by the Board of Directors:

a. This deferral election applies only to Common Stock underlying RSUs and/or performance shares or units granted under the 2012 LTIP.

b. Such award will be settled, to the extent vested, in accordance with my irrevocable deferral election set forth herein.

c. To the extent vested, such retainer will be paid in a lump sum and solely in shares of Common Stock, and will not be credited to any of the options set forth on the Cash Retainer Deferral Allocation Form provided herewith.

d. If a dividend equivalent award has been granted with a deferred RSU or performance share or unit award, such dividend equivalent award shall also be deferred under the terms provided herein. Such dividends shall continue to be credited, when and as declared and paid by the Board of Directors, in additional shares or units of the same type and tenor as the stock-based award, based on the Fair Market Value (as defined in the 2012 LTIP) on the business day prior to the payment date of such dividend.

e. Upon payment of deferred awards, fractional shares shall be eliminated without compensation. Any fractional shares shall be rounded up to the next whole share if greater than or equal to a half-share, and rounded down to the next whole share if less than a half-share.

f. The award and deferral is subject to the other terms and conditions of the 2012 LTIP, as well as vesting, forfeiture, tax withholding and other legal requirements and conditions with respect to such award and deferral.

g. The Board of Directors retains full discretion over the terms of this deferral arrangement and may amend, suspend or terminate such arrangement at any time or from time to time, or impose additional or different restrictions, conditions or limitations on such deferral at any time as permitted or not prohibited by the terms of 2012 LTIP.

h. The terms of my deferral election are intended to comply, and should be interpreted consistently with, Section 409A of the Internal Revenue Code of 1986, as amended.

IN WITNESS WHEREOF, the undersigned has executed this Agreement effective for all purposes as of the __ day of __________, 2013.

____
Signature

____
Name (Please Print)

Acknowledged and confirmed this __ day of __________, 2013

Pepco Holdings, Inc.

____
Signature

____
Name (Please Print)

Pepco Holdings, Inc.

CASH RETAINER DEFERRAL ALLOCATION FORM

Name: ____ (the "Participant")
Last First Middle Initial

Social Security Number: ______ - ______ - ______

I request that the Company credit my election of my cash deferred amounts in the Second Revised and Restated Executive and Director Deferred Compensation Plan to the options indicated below:

(Minimum per fund – 10%) (Please be sure your percentages total = 100%)

______% Money Market
______% Equity
______% Government Income
______% Value
______% Conserv. Balanced
______% Global
______% Small Cap Stock
______% Am Cent. Value Fund
______% MFS Emerg. Growth
______% Pepco Holdings Phantom Shares
______% High Yield Bond
______% Diversified Bond
______% Stock Index
______% Natural Resources
______% Flexible Managed
______% Prudential Jennison
______% Prime Rate
______% Janus Aspen Growth
______% TRP Int'l Stock

NOTE: If you have elected to defer the settlement of your stock-based annual retainer award under the 2012 LTIP, you do not need to complete this Cash Retainer Deferral Allocation Form unless you are also deferring in whole or in part your annual cash retainer and/or meeting fees.

Participant

____
Signature

____
Date

Pepco Holdings, Inc.
Executive and Director Deferred Compensation Plan
2014 Plan Year Salary Election Form – Executive

Please complete and sign this form and send it to the attention of Ned Dove – Rm. 4025 at Edison Place.

Personal Information

Last	**First**	**Middle**
Social Security Number		**E-mail Address**

I elect to participate in the Pepco Holdings, Inc. Executive and Director Deferred Compensation Plan (the “Plan”) with respect to the time period January 1, 2014 to December 31, 2014. I have received a copy of the Plan and understand the terms and conditions of the Plan. I further understand that with respect to the deferral election I have made herein, notwithstanding the terms of the Plan, the following shall apply:

1. I can only receive the deferrals elected herein in accordance with my election below or, in the case of death or an unforeseen financial emergency; and
2. I further understand that if I meet the definition of “Specified Employee” under the applicable provisions of the Internal Revenue Code, notwithstanding my election herein, the earliest I can receive my compensation deferred herein that is payable upon a separation from service is six (6) months and one day after my separation from service; and
3. I cannot change the time or form of my deferral made herein unless
   a. such revised election is not effective for 12 months after it is made;
   b. such revised election if made for a distribution at a specified time or on a fixed schedule is made at least 12 months prior to the first scheduled payment; and
   c. an election to delay a distribution must be for a period of at least five years.

Deferral Election – Base Salary

Please select all that apply.

• **Defer Evenly Throughout the Year** (no matching credits)	I hereby elect to defer ______% of my Base Salary paid each pay period in 2014. I understand that none of my deferrals under this deferral option will be credited with matching contributions.
• **Defer to Obtain Missed Matching Contributions in 401 (k) Plan**	I hereby elect to defer 6% of my Base Salary to the extent (if any) that my Base Salary exceeds $260,000. My deferrals under this option will be matched with credits in my Plan account based on the matching contribution formula in the 401(k) plan in which I participate. I understand that this deferral option is intended to provide an amount of deferrals necessary to obtain matching contributions that the Internal Revenue Code prevents from being made under the 401(k) plan. However, my deferrals under this deferral option will be made without regard to any election I actually make (or do not make) under the 401(k) Plan.
• **Non-Participation**	I elect not to defer any portion of my Base Salary in the 2014 Plan Year.

Benefit Payout Election

I elect to have the above-referenced deferred amounts paid to me beginning *(check one)*:

- (i) on the first day of the month following my separation from service.
- (ii) on January 31 of the calendar year following my separation from service.
- (iii) on January 31 of the calendar year following the later of my attainment of age ______ or separation from service.
- (iv) on January 31 of ______ *(Note: The designated year may not be earlier than 2016)*.

Manner of Payment

Benefits deferred under the Plan shall be paid to me (or, if applicable, my beneficiary) in the following manner *(check one)*. Note that recent changes to the tax law may require that payments to an executive who is a "Specified Employee" be delayed for a period of six (6) months and one day following the executive's termination of employment:

- a lump sum.
- annual installments over ______ *(2-15)* years.
- monthly installments over ______ *(24-180)* months.

I further recognize that nothing contained herein or in the Plan shall be construed as a contract of employment between me and Pepco Holdings, Inc., as a right to continue employment or as a limitation of Pepco Holdings, lnc.'s right of discharge. In addition, Pepco Holdings, Inc. and its subsidiaries reserve the right to amend or terminate its employee benefit plans, including this Plan, at any time, subject to the terms of those plans.

I understand that if I die during active service, my beneficiary shall receive an amount equal to two times my account balance resulting from deferrals under this agreement.

Asset Allocation Election

I elect to allocate my new deferrals to the following Measurement Funds (percentage total must equal 100%):

Prudential Conservative Balanced	%
Prudential Flexible Managed	%
Prudential Money Market	%
Prudential Government Income	%
Prudential Diversified Bond	%
Prudential High Yield Bond	%
Prudential Value	%
American Century VP Value	%
Prudential Stock Index	%
Prudential Equity	%
Prudential Jennison	%
MFS VIT Growth	%
Janus Aspen Janus Portfolio	%
Prudential Small Capitalization Stock	%
Prudential Global	%
T. Rowe Price International Stock	%
Prudential Natural Resources	%
Prime Rate Fund	%
Total	**100%**

Please note that these elections affect future deferrals only. To change your current allocations, please log onto your account at plandestination.com.

Acknowledged & Accepted as of the Date Indicated (Please Sign Below)

Signature of Participant **Date**

Signature of Committee Member **Date**

Pepco Holdings, Inc.
Executive and Director Deferred Compensation Plan
Salary Beneficiary Designation – Executive

Please complete and sign this form and send it to the attention of Ned Dove – Rm. 4025 at Edison Place.

Personal Information

Last	**First**	**Middle**	**Social Security Number**

I hereby designate the following Beneficiary(ies) to receive any benefit payable under the Plan by reason of my death, as provided in the Plan document.

Primary Beneficiary(ies) (Whole percentages only and must total 100%)

Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**
Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**
Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**

Contingent Beneficiary(ies) (Whole percentages only and must total 100%)

Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**
Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**

Spousal Consent

I, __________, am the spouse of __________. I acknowledge that my spouse has named someone other than me as a Primary Beneficiary of the survivor benefit under the Pepco Holdings, Inc. Executive and Director Deferred Compensation Plan, and I hereby approve of that designation. I agree that the designation shall be binding upon me with the same effect as if I had personally executed said designation.

Signature of Spouse **Date**

- Check the box if you are **not** married and thus the "Spousal Consent" does not apply.

Please Sign Below

This Beneficiary Designation Form is effective until the participant files another such designation.

Signature of Participant **Date**

Pepco Holdings, Inc.
Executive and Director Deferred Compensation Plan
2014 Plan Year Incentive Compensation Election Form – Executive

---

Please complete and sign this form and send it to the attention of Ned Dove – Rm. 4025 at Edison Place.

Personal Information – the "Participant"

Last	**First**	**Middle**

Social Security Number	**E-mail Address**

I elect to participate in the Pepco Holdings, Inc. Executive and Director Deferred Compensation Plan (the "Plan") with respect to the time period January 1, 2014 to December 31, 2014. I have received a copy of the Plan and understand the terms and conditions of the Plan. I further understand that with respect to the deferral election I have made herein, notwithstanding the terms of the Plan, the following shall apply:

1. I can only receive the deferrals elected herein in accordance with my election below or, in the case of death or an unforeseen financial emergency; and
2. I further understand that if I meet the definition of "Specified Employee" under the applicable provisions of the Internal Revenue Code, notwithstanding my election herein, the earliest I can receive my compensation deferred herein that is payable upon a separation from service is six (6) months and one day after my separation from service; and
3. I cannot change the time or form of my deferral made herein unless
   a. such revised election is not effective for 12 months after it is made;
   b. such revised election if made for a distribution at a specified time or on a fixed schedule is made at least 12 months prior to the first scheduled payment; and
   c. an election to delay a distribution must be for a period of at least five years.

Deferral Election – Incentive Compensation

In the event that an incentive award becomes payable to me for the 2014 Plan Year, I hereby irrevocably elect:

- that ______% of the award is to be paid in a lump sum upon determination of the award.
- that ______% of the award is to be deferred.

Benefit Payout Election

I elect to have the above-referenced deferred amounts paid to me beginning *(check one)*:

- (i) on the first day of the month following my separation from service.
- (ii) on January 31 of the calendar year following my separation from service.
- (iii) on January 31 of the calendar year following the later of my attainment of age ______ or separation from service.
- (iv) on January 31 of ______ *(Note: The designated year may not be earlier than 2016)*.

Manner of Payment

Benefits deferred under the Plan shall be paid to me (or, if applicable, my beneficiary) in the following manner *(check one)*. Note that recent changes to the tax law may require that payments to an executive who is a "Specified Employee" be delayed for a period of six (6) months and one day following the executive's termination of employment:

- a lump sum.
- annual installments over ______ *(2-15)* years.
- monthly installments over ______ *(24-180)* months.

I further recognize that nothing contained herein or in the Plan shall be construed as a contract of employment between me and Pepco Holdings, Inc., as a right to continue employment or as a limitation of Pepco Holdings, Inc.'s right of discharge.

I understand that if I die during active service, my beneficiary shall receive an amount equal to two times my account balance resulting from deferrals under this agreement.

Asset Allocation Election

I elect to allocate my new deferrals to the following Measurement Funds (percentage total must equal 100%):

Prudential Conservative Balanced	%
Prudential Flexible Managed	%
Prudential Money Market	%
Prudential Government Income	%
Prudential Diversified Bond	%
Prudential High Yield Bond	%
Prudential Value	%
American Century VP Value	%
Prudential Stock Index	%
Prudential Equity	%
Prudential Jennison	%
MFS VIT Growth	%
Janus Aspen Janus Portfolio	%
Prudential Small Capitalization Stock	%
Prudential Global	%
T. Rowe Price International Stock	%
Prudential Natural Resources	%
Prime Rate Fund	%
Total	**100%**

Please note that these elections affect future deferrals only. To change your current allocations, please log onto your account at plandestination.com.

I have been designated as a participant in the Pepco Holdings, Inc. Amended and Restated Executive Incentive Compensation Plan (the "EICP") for the 2014 Plan Year. I have received a copy of the Plan and the EICP, and understand the terms and conditions of the Plan and the EICP, all of which are hereby incorporated into this agreement.

Acknowledged & Accepted (Please Sign Below)

Signature of Participant	**Date**
Signature of Committee Member	**Date**

Pepco Holdings, Inc.
Executive and Director Deferred Compensation Plan
Incentive Compensation Beneficiary Designation – Executive

Please complete and sign this form and send it to the attention of Ned Dove – Rm. 4025 at Edison Place.

Personal Information

Last	**First**	**Middle**	**Social Security Number**

I hereby designate the following Beneficiary(ies) to receive any benefit payable under the Plan by reason of my death, as provided in the Plan document.

Primary Beneficiary(ies) (Whole percentages only and must total 100%)

Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**
Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**
Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**

Contingent Beneficiary(ies) (Whole percentages only and must total 100%)

Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**
Beneficiary Name	**Percentage**
Relationship to Participant	**Social Security Number**

Spousal Consent

I, __________, am the spouse of __________. I acknowledge that my spouse has named someone other than me as a Primary Beneficiary of the survivor benefit under the Pepco Holdings, Inc. Executive and Director Deferred Compensation Plan, and I hereby approve of that designation. I agree that the designation shall be binding upon me with the same effect as if I had personally executed said designation.

Signature of Spouse	**Date**

- Check the box if you are **not** married and thus the "Spousal Consent" does not apply.

Please Sign Below

This Beneficiary Designation Form is effective until the participant files another such designation.

Signature of Participant	**Date**

Exhibit 10.51

NAMED EXECUTIVE OFFICER COMPENSATION DETERMINATIONS

2014 Named Executive Officer Compensation Determinations

The following is a description of certain compensation decisions made in 2014 by the Pepco Holdings, Inc. (PHI) Board of Directors (the Board) and/or the Compensation/Human Resources Committee of the Board (the Committee) with respect to compensation to be earned or payable in 2014 to (i) persons set forth in the first table below who are identified as named executive officers (each, a Named Executive Officer) in the Summary Compensation Table in PHI's proxy statement for its 2013 Annual Meeting of Stockholders (the 2013 Proxy Statement), and (ii) one executive officer of PHI who was not identified as a named executive officer in the 2013 Proxy Statement but who is anticipated to be identified as a named executive officer of PHI in PHI's proxy statement for its 2014 Annual Meeting of Stockholders.

As to each Named Executive Officer listed in the table immediately below, the compensation decisions consisted of (i) the establishment of annual base salary for 2014; (ii) the establishment of the Named Executive Officer's 2014 annual cash incentive award opportunities under the Amended and Restated Executive Incentive Compensation Plan (the EICP); and (iii) the grant of long-term restricted stock unit (RSU) awards under the Pepco Holdings, Inc. 2012 Long-Term Incentive Plan (the LTIP). In addition, with respect to Joseph M. Rigby, PHI's Chairman of the Board, President and Chief Executive Officer, the performance goals for a performance-based RSU award pursuant to the terms of his employment agreement were established in February 2014, as discussed below.

				LTIP Awards (2)			
				Performance-Based RSU Awards (# of RSUs) (3)			
Named Executive Officer	Title	2014 Annual Base Salary	Target 2014 Annual Cash EICP Award Opportunity as a Percentage of Annual Base Salary (1)	Threshold	Target	Maximum	Time-Based RSU Award (# of RSUs) (4)
Joseph M. Rigby (5)	Chairman of the Board, President and Chief Executive Officer	$1,015,000	100%	22,317	89,270	178,540	44,635
David M. Velazquez	Executive Vice President	$ 534,000	60%	5,871	23,482	46,964	11,741
Frederick J. Boyle	Senior Vice President and Chief Financial Officer	$ 500,000	60%	5,497	21,987	43,974	10,993
Kevin C. Fitzgerald (5)	Executive Vice President and General Counsel	$ 550,000	60%	6,047	24,186	48,372	12,093

(1) Each executive may earn a cash incentive award of up to 180% (subject to the exercise of negative discretion as described below) of his target award opportunity under the EICP as determined by the Committee, depending on the extent to which the pre-established performance goals are achieved. See "Amended and Restated Executive Incentive Compensation Plan" below for a discussion of 2014 performance goals.

(2) The shares of PHI common stock, $.01 par value per share (Common Stock), underlying performance-based and time-based RSU awards in the aggregate had a fair market value on the date of grant equal to the following percentage of the Named Executive Officer's 2014 annual base salary: 250% for Mr. Rigby and 125% for each of Messrs. Velazquez, Boyle and Fitzgerald.

(3) See "2014 LTIP Awards — Performance-Based RSU Awards" below for a description of the annual performance-based RSU awards granted under the LTIP.

(4) See "2014 LTIP Awards — Time-Based RSU Awards" below for a description of the annual time-based RSU awards granted under the LTIP.

(5) In addition to the awards listed in the table above, in February 2014, Mr. Rigby received, and Mr. Fitzgerald is eligible to receive, a performance-based RSU award pursuant to the terms of his employment agreement. Each such award has or will have a performance period beginning on January 1, 2014 and ending on December 31, 2014 and which will vest: (i) if the executive remains continuously employed by PHI during the performance period and (ii) to the extent that performance goals (described below) with respect to such performance period are met. Mr. Fitzgerald also received in 2014 a $15,000 non-base adjustment in cash with respect to his performance in 2013.

As to the executive officer of PHI listed in the table immediately below, the compensation decisions consisted of (i) the establishment of annual base salary for 2014; (ii) the establishment of a 2014 annual cash incentive award opportunity under the EICP; and (iii) the grant of long-term RSU awards under the LTIP.

				LTIP Awards (2)			
				Performance-Based RSU Award (# of RSUs) (3)			
Executive Officer	Title	2014 Annual Base Salary	Target 2014 Annual Cash EICP Award Opportunity as a Percentage of Annual Base Salary (1)	Threshold	Target	Maximum	Time-Based RSU Award (# of RSUs) (4)
John U. Huffman	President, Pepco Energy Services, Inc.	$ 388,000	60%	3,412	13,649	27,298	6,824

(1) Mr. Huffman may earn a cash incentive award of up to 180% (subject to the exercise of negative discretion as described below) of his target award opportunity under the EICP as determined by the Committee, depending on the extent to which the pre-established performance goals are achieved. See "Amended and Restated Executive Incentive Compensation Plan" below for 2014 performance goals.

(2) The shares of Common Stock underlying performance-based and time-based RSU awards in the aggregate had a market value on the date of grant equal to 100% of Mr. Huffman's 2014 annual base salary.

(3) See "2014 LTIP Awards — Performance-Based RSU Awards" below for a description of the performance-based RSU award issued under the LTIP.

(4) See "2014 LTIP Awards — Time-Based RSU Awards" below for a description of the time-based RSU award issued under the LTIP.

Amended and Restated Executive Incentive Compensation Plan

Each of the executives listed in the tables above is a participant in the EICP. On February 27, 2014, the Committee established the following performance goals to be used for the determination of 2014 EICP awards for each of the executives named below:

- Messrs. Rigby, Boyle and Fitzgerald: (1) net earnings per share, (2) electric system reliability, (3) customer satisfaction, (4) diversity, and (5) safety.
- Mr. Velazquez: (1) Power Delivery earnings per share (excluding certain items), (2) core capital expenditures, compared to budget (excluding certain items), (3) operation and maintenance spending, compared to budget, (4) compliance results, (5) electric system reliability, (6) customer satisfaction, (7) diversity, and (8) safety.
- Mr. Huffman: (1) Pepco Energy Services' net income (excluding power plants), (2) performance of Pepco Energy Services' energy savings performance contracting business, (3) net income from power plants, (4) performance of Pepco Energy Services' undergrounding transmission and distribution business, (5) diversity, and (6) safety.

The payment of awards under the EICP to each of these PHI executives is also conditioned upon the achievement by PHI of specified threshold earnings requirements in order for an EICP award to be paid to the executive, regardless of the extent to which the other performance goals may be achieved. The EICP award opportunities discussed in the tables above do not reflect any discretion by the Compensation Committee under the terms of the EICP to increase or reduce an award by up to 30% (subject to compliance with Section 162(m) of the Internal Revenue Code of 1986 (the Code)).

2014 LTIP Awards

The Committee has granted awards of performance-based RSUs and time-based RSUs under the LTIP with respect to the 2014 to 2016 performance/retention cycle. Participants in the LTIP are key employees and officers of PHI and its subsidiaries selected by the Chairman of the Board of PHI and approved by the Committee, as well as non-management directors of PHI, including each of the persons listed in the tables above. Subject to the terms and conditions of each RSU award, each RSU represents a contractual right to receive one share of Common Stock at the end of the restriction or performance period. When a dividend is paid on the Common Stock, the award is credited with additional RSUs equal to the number of RSUs subject to such award multiplied by the per share cash dividend, divided by the then current market price of a share of Common Stock. Additional RSUs credited as dividend equivalents will vest only to the extent the underlying RSUs vest.

Performance-Based RSU Awards

A performance-based RSU award accounts for two-thirds of an executive's aggregate 2014 equity award under the LTIP. Depending on the extent to which the pre-established performance goal, which is based on PHI's total shareholder return relative to a PHI-selected group of peer companies (the 2014 Utility Peer Group) over a three-year period beginning on January 1, 2014 and ending on December 31, 2016, has been met, an amount of each award ranging from 25% to 200% of the target number of RSUs (including dividend equivalents credited in the form of additional RSUs) subject to the award may vest. If during the course of the three-year performance period, a significant event occurs, as determined in the discretion of the Committee, which the Committee expects to have a substantial effect on total shareholder return during the period, the Committee may revise such measures, other than with respect to awards to "covered employees" subject to Section 162(m) of the Code. No adjustment shall be made that causes an award to fail to comply with Section 162(m) of the Code. Vesting amounts related to threshold (representing 25% of the target award opportunity), target and maximum (representing 200% of the target award opportunity), with respect to each performance-based award of RSUs for each executive, are shown in the tables above.

Subject to certain exceptions provided for in the LTIP and/or in the award agreement (or, with respect to Mr. Rigby, his employment agreement), performance-based awards are subject to forfeiture if (i) the employment of the executive terminates before the end of the three-year performance period or (ii) the performance goal has not been achieved as of the end of the three-year performance period.

Time-Based RSU Awards

Each executive listed above has received a grant of time-based RSUs, which accounts for one-third of the executive's aggregate 2014 equity award under the LTIP. Subject to certain exceptions provided for in the LTIP or in the award agreement (or, with respect to Mr. Rigby, his employment agreement), time-based RSUs are subject to forfeiture if the employment of the executive terminates prior to the third anniversary of the date of grant.

Performance-Based RSU Awards Pursuant to Employment Agreements

Mr. Rigby

Pursuant to the terms of his employment agreement with PHI, Mr. Rigby is entitled to receive a series of three annual performance-based awards of 36,945 RSUs, each granted under the LTIP, over the three-year term of his employment agreement. Each award will have a performance period that begins on January 1 and ends on December 31. Each award will vest if Mr. Rigby remains continuously employed with PHI during the related performance period and to the extent that the Committee determines that the performance goals established for that performance period have been met. The performance goals for each award are established on or as soon as practicable after the beginning of each performance period, but no later than 90 days after such date. The performance goals established by the Committee in February 2014 with respect to Mr. Rigby's 2014 performance-based award under his employment agreement are as follows:

- Reliability of electric service to customers (20% weight);
- Residential customer satisfaction (15% weight);
- Achievement of at least the mid-point of PHI's 2014 earnings guidance range (15% weight); and
- Achievement of total shareholder return relative to 2014 Utility Peer Group based on measurement period from January 1, 2014 to December 31, 2014 (50% weight).

Mr. Fitzgerald

Pursuant to the terms of his employment agreement with PHI, Mr. Fitzgerald is entitled to receive a series of three annual performance-based awards, each granted under the LTIP, over the three-year term of his employment agreement. Each award will have a performance period that begins on January 1 and ends on December 31. The awards will consist of a number of RSUs to be determined by dividing $166,666.67 by the closing price of a share of Common Stock on the last trading day immediately preceding the first day of the performance period. These awards will vest if Mr. Fitzgerald remains continuously employed with PHI during each annual performance period and to the extent that the Committee determines that the performance goals established for the performance period covered by the award have been met. The performance goals for each award will be established on or as soon as practicable after the beginning of each performance period, but no later than 90 days after such date, from among the performance criteria set forth in the LTIP.

Exhibit 10.52

ELECTION OF TAX WITHHOLDING FOR SERVICE-BASED AND PERFORMANCE-BASED AWARDS

As a Participant in the Pepco Holdings, Inc. Long-Term Incentive Plan (the "Plan"), I was granted Service-Based Restricted Stock Unit Awards and Performance-Based Restricted Stock Unit Awards during the year 2011, for the performance cycle 2011 to 2013. I understand that minimum statutory withholdings for certain federal, state, local or other taxes are required for Awards which I have been granted under the Plan, which in the case of Performance-Based Awards will be determined after the Board of Directors has determined if, and to what extent, the performance goals related to such Award have been met. I elect to use the following method to meet the minimum statutory withholding requirements (**please check one of the boxes below**).

☐ I hereby elect that such number of shares of Stock having a Fair Market Value equal to the minimum statutory requirement for federal, state and local withholding and other taxes due upon vesting of Awards which I have been granted under the Plan, shall be withheld from the settlement of such Awards.

☐ I will satisfy the minimum statutory requirement for taxes due with respect to such Awards by the payment of cash immediately upon notification by the Company of the minimum statutory requirement for federal, state and local withholding and other taxes due upon vesting of such Awards.

☐ I will satisfy the minimum statutory requirement for taxes due with respect to such Awards by delivery to the Company, immediately upon its notification to me, of the number of shares of Stock I own (other than the shares I receive under the Award) having a Fair Market Value equal to the minimum statutory requirement for federal, state and local withholding and other taxes due upon vesting of such Awards.

Capitalized terms used herein, which are not defined herein, have the meanings given in the Plan.

Date:

____
Signature

____
Print Name

Exhibit 12.1 *Statements Re: Computation of Ratios*

PEPCO HOLDINGS, INC.

	For the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(millions of dollars)				
Earnings					
Net income from continuing operations	$ 110	$ 218	$ 222	$ 91	$ 163
Preferred stock dividend	—	—	—	—	—
(Income) or loss from equity investees	(2)	(1)	3	1	(2)
Minority interest loss	—	—	—	—	—
Income tax expense (benefit) related to continuing operations	319	103	114	(14)	80
Pre-tax income for common stock	427	320	339	78	241
Add: Fixed charges*	301	286	275	312	332
Add: Distributed income of equity investees	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—
Earnings	$ 728	$ 606	$ 614	$ 390	$ 573
***Fixed Charges**					
Interest on long-term debt	$ 265	$ 249	$ 239	$ 269	$ 286
Interest capitalized	—	—	—	—	—
Other interest	—	—	—	—	—
Amortization of debt discount, premium, and expense	14	16	14	21	23
Interest component of rentals	22	21	22	22	23
Pre-tax preferred stock dividend requirement	—	—	—	—	—
Fixed charges	$ 301	$ 286	$ 275	$ 312	$ 332
Ratio of earnings to fixed charges (a)	2.42	2.12	2.23	1.25	1.73

(a) Pepco Holdings, Inc. has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 12.2 Statements Re: Computation of Ratios

POTOMAC ELECTRIC POWER COMPANY

	For the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(millions of dollars)				
Earnings					
Net income for common stock	$ 150	$ 126	$ 99	$ 108	$ 106
Preferred stock dividend	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—
Minority interest loss	—	—	—	—	—
Income tax expense	79	48	36	37	76
Pre-tax income for common stock	229	174	135	145	182
Add: Fixed charges*	121	113	111	111	114
Add: Distributed income of equity investees	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—
Earnings	$ 350	$ 287	$ 246	$ 256	$ 296
***Fixed Charges**					
Interest on long-term debt	$ 109	$ 101	$ 97	$ 97	$ 99
Interest capitalized	—	—	—	—	—
Other interest	—	—	—	—	—
Amortization of debt discount, premium, and expense	5	5	4	4	4
Interest component of rentals	7	7	10	10	11
Pre-tax preferred stock dividend requirement	—	—	—	—	—
Fixed charges	$ 121	$ 113	$ 111	$ 111	$ 114
Ratio of earnings to fixed charges (a)	2.89	2.54	2.22	2.31	2.60

(a) Pepco has no preference equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 12.3 *Statements Re: Computation of Ratios*

DELMARVA POWER & LIGHT COMPANY

	For the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(millions of dollars)				
Earnings					
Net income for common stock	$ 89	$ 73	$ 71	$ 45	$ 52
Preferred stock dividend	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—
Minority interest loss	—	—	—	—	—
Income tax expense	56	44	42	31	16
Pre-tax income for common stock	145	117	113	76	68
Add: Fixed charges*	55	52	49	48	47
Add: Distributed income of equity investees	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—
Earnings	$ 200	$ 169	$ 162	$ 124	$ 115
***Fixed Charges**					
Interest on long-term debt	$ 49	$ 45	$ 42	$ 43	$ 42
Interest capitalized	—	—	—	—	—
Other interest	—	—	—	—	—
Amortization of debt discount, premium, and expense	3	4	4	3	3
Interest component of rentals	3	3	3	2	2
Pre-tax preferred stock dividend requirement	—	—	—	—	—
Fixed charges	$ 55	$ 52	$ 49	$ 48	$ 47
Ratio of earnings to fixed charges (a)	3.64	3.25	3.31	2.58	2.45

(a) DPL has no preference equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 12.4 *Statements Re: Computation of Ratios*

ATLANTIC CITY ELECTRIC COMPANY

	For the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(millions of dollars)				
Earnings					
Net income for common stock	$ 50	$ 35	$ 39	$ 53	$ 41
Preferred stock dividend	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—
Minority interest loss	—	—	—	—	—
Income tax expense	19	18	33	43	17
Pre-tax income for common stock	69	53	72	96	58
Add: Fixed charges*	72	75	74	69	72
Add: Distributed income of equity investees	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—
Earnings	$ 141	$ 128	$ 146	$ 165	$ 130
***Fixed Charges**					
Interest on long-term debt	$ 65	$ 69	$ 69	$ 63	$ 67
Interest capitalized	—	—	—	—	—
Other interest	—	—	—	—	—
Amortization of debt discount, premium, and expense	3	2	2	3	2
Interest component of rentals	4	4	3	3	3
Pre-tax preferred stock dividend requirement	—	—	—	—	—
Fixed charges	$ 72	$ 75	$ 74	$ 69	$ 72
Ratio of earnings to fixed charges (a)	1.96	1.71	1.97	2.39	1.81

(a) ACE has no preference equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 21 Subsidiaries of the Registrants

Name of Company	Jurisdiction of Incorporation or Organization
Pepco Holdings, Inc.	DE
Potomac Electric Power Company	DC and VA
POM Holdings, Inc.	DE
Pepco Energy Services, Inc.	DE
Conectiv Thermal Systems, Inc. (d/b/a Pepco Energy Services)	DE
ATS Operating Services, Inc.	DE
Atlantic Jersey Thermal Systems, Inc.	DE
Thermal Energy Limited Partnership I	DE
Potomac Power Resources, LLC	DE
Pepco Government Services LLC	DE
Pepco Energy Solutions LLC	DE
Pepco Energy Cogeneration LLC	DE
Fauquier Landfill Gas, L.L.C.	DE
Distributed Generation Partners, LLC	DE
Bethlehem Renewable Energy, LLC	DE
Rolling Hills Landfill Gas, LLC	DE
Blue Ridge Renewable Energy, LLC	DE
Eastern Landfill Gas, LLC	DE
Pepco Building Services Inc.	DE
Severn Construction Services, L.L.C.	DE
Chesapeake HVAC, Inc.	DE
W.A. Chester, L.L.C.	DE
W.A. Chester Corporation	DE
Chester Transmission Construction Canada, Inc.	Canada
Potomac Capital Investment Corporation	DE
PCI Energy Corporation	DE
AMP Funding, L.L.C.	DE
RAMP Investments, L.L.C.	DE
PCI Air Management Partners, L.L.C.	DE
PCI Ever, Inc.	DE
Kinetic Ventures VI, L.L.C.	DE
Kinetic Ventures VII, L.L.C.	DE
Friendly Skies, Inc.	Virgin Islands
PCI Air Management Corporation, a Nevada Corporation	NV
PCI-BT Investing, L.L.C.	DE
American Energy Corporation	DE
PCI Engine Trading Ltd.	Bermuda
Potomac Delaware Leasing Corporation	DE
Potomac Leasing Associates, L.P.	DE
PHI Service Company	DE
Conectiv, LLC	DE
Delmarva Power & Light Company (d/b/a Delmarva Power)	DE and VA
Conectiv Properties and Investments, Inc.	DE
Atlantic City Electric Company (d/b/a Atlantic City Electric)	NJ
Atlantic City Electric Transition Funding LLC	DE

Name of Company	Jurisdiction of Incorporation or Organization
Conectiv Solutions LLC	DE
Blacklight Power, Inc.	DE
Millennium Account Services, LLC	DE
Conectiv Services, Inc.	DE
ATE Investment, Inc.	DE
Enertech Capital Partners II L.P.	DE
Conectiv Communications, Inc.	DE
Atlantic Generation, Inc.	NJ
Project Finance Fund III, L.P.	DE
Vineland Ltd., Inc.	DE
Vineland Cogeneration Limited Partnership	DE
Vineland General, Inc.	DE
Atlantic Southern Properties, Inc.	NJ
Tech Leaders II, L.P.	DE
Delaware Operating Services Company, LLC	DE
Conectiv Energy Supply, Inc. (d/b/a Conectiv Energy and Petron Oil)	DE
Conectiv North East, LLC	DE
Energy Systems North East, LLC	DE

Exhibit 23.1

<u>CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM</u>

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-190917 and 333-190923) and the Registration Statements on Form S-8 (Nos. 333-96675, 333-121823, 333-181505 and 333-189291) of Pepco Holdings, Inc. of our report dated February 27, 2014, for Pepco Holdings, Inc. relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, which appear in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

<u>CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM</u>

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-190917-03) of Potomac Electric Power Company of our report dated February 27, 2014, for Potomac Electric Power Company relating to the financial statements and financial statement schedule, which appear in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-190917-02) of Delmarva Power & Light Company of our report dated February 27, 2014, for Delmarva Power & Light Company relating to the financial statements and financial statement schedule, which appear in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-190917-01) of Atlantic City Electric Company of our report dated February 27, 2014, for Atlantic City Electric Company relating to the financial statements and financial statement schedule, which appear in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 27, 2014

Exhibit 31.1

CERTIFICATIONS

I, Joseph M. Rigby, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ JOSEPH M. RIGBY

Joseph M. Rigby
Chairman of the Board, President
and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ FRED J. BOYLE

Frederick J. Boyle
Senior Vice President and
Chief Financial Officer

Exhibit 31.3

CERTIFICATIONS

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.4

CERTIFICATIONS

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ FRED J. BOYLE

Frederick J. Boyle
Senior Vice President and
Chief Financial Officer

Exhibit 31.5

CERTIFICATIONS

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.6

CERTIFICATIONS

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ FRED J. BOYLE
Frederick J. Boyle
Senior Vice President and
Chief Financial Officer

Exhibit 31.7

CERTIFICATIONS

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-K 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: February 27, 2014

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

CERTIFICATIONS

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-K 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 controls over financial reporting, or caused such internal controls 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: February 27, 2014

/s/ FRED 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, certify that, to the best of my knowledge, (i) the Report on Form 10-K of Pepco Holdings, Inc. for the year ended December 31, 2013 filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings, Inc.

February 27, 2014	/s/ JOSEPH M. RIGBY
	Joseph M. Rigby Chairman of the Board, President and Chief Executive Officer
February 27, 2014	/s/ FRED 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, certify that, to the best of my knowledge, (i) the Report on Form 10-K of Potomac Electric Power Company for the year ended December 31, 2013 filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

February 27, 2014	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
February 27, 2014	/s/ FRED 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.

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, certify that, to the best of my knowledge, (i) the Report on Form 10-K of Delmarva Power & Light Company for the year ended December 31, 2013 filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

February 27, 2014	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
February 27, 2014	/s/ FRED 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, certify that, to the best of my knowledge, (i) the Report on Form 10-K of Atlantic City Electric Company for the year ended December 31, 2013 filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

February 27, 2014	/s/ DAVID M. VELAZQUEZ
	David M. Velazquez President and Chief Executive Officer
February 27, 2014	/s/ FRED J. BOYLE
	Frederick J. Boyle Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Atlantic City Electric Company and will be retained by Atlantic City Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 3

EXHIBIT 3

EXECUTION VERSION

AGREEMENT AND PLAN OF MERGER

Among

PEPCO HOLDINGS, INC.,

EXELON CORPORATION

and

PURPLE ACQUISITION CORP.

Dated as of April 29, 2014

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AGREEMENT AND PLAN OF MERGER

AGREEMENT AND PLAN OF MERGER (hereinafter called this "Agreement"), dated as of April 29, 2014, among Pepco Holdings, Inc., a Delaware corporation (the "Company"), Exelon Corporation, a Pennsylvania corporation ("Parent"), and Purple Acquisition Corp., a Delaware corporation and a wholly-owned subsidiary of Parent ("Merger Sub," the Company and Merger Sub sometimes being hereinafter collectively referred to as the "Constituent Corporations").

RECITALS

WHEREAS, the respective boards of directors of each of Parent, Merger Sub and the Company have approved and declared advisable this Agreement and the merger of Merger Sub with and into the Company (the "Merger") upon the terms and subject to the conditions set forth in this Agreement and have authorized the execution hereof, and the board of directors of the Company has adopted a resolution recommending that the plan of merger set forth in this Agreement be adopted by the stockholders of the Company;

WHEREAS, pursuant to a subscription agreement between the Company and Parent entered into on the date hereof (the "Subscription Agreement"), the Company will issue, sell and deliver to Parent, and Parent will subscribe for and purchase from the Company, up to 18,000 new shares of preferred stock, par value $0.01 per share, having the relative rights, preferences, limitations and restrictions as set forth in a certificate of designation substantially in the form of Exhibit C hereto (the "Nonvoting Preferred Stock"), on the terms and subject to the conditions set forth in the Subscription Agreement (as of any date of determination, the purchase price actually paid to the Company for such shares is referred to as the "Nonvoting Preferred Stock Purchase Price"); and

WHEREAS, the Company, Parent and Merger Sub desire to make certain representations, warranties, covenants and agreements in connection with this Agreement.

NOW, THEREFORE, in consideration of the premises, and of the representations, warranties, covenants and agreements contained herein, the parties hereto agree as follows:

ARTICLE I

The Merger; Closing; Effective Time

1.1. The Merger. Upon the terms and subject to the conditions set forth in this Agreement, at the Effective Time, Merger Sub shall be merged with and into the

Company and the separate corporate existence of Merger Sub shall thereupon cease. The Company shall be the surviving corporation in the Merger (sometimes hereinafter referred to as the "Surviving Corporation"), and the separate corporate existence of the Company, with all of its rights, privileges, immunities, powers and franchises, shall continue unaffected by the Merger, except as set forth in Article II. The Merger shall have the effects specified in the Delaware General Corporation Law, as amended (the "DGCL").

1.2. Closing. Unless otherwise mutually agreed in writing between the Company and Parent, the closing for the Merger (the "Closing") shall take place at the offices of Sullivan & Cromwell LLP, 1700 New York Avenue, N.W. Suite 700, Washington, D.C., at 9:00 a.m. (Eastern Time) on the second business day (the "Closing Date") following the day on which the last to be satisfied or waived of the conditions set forth in Article VII (other than those conditions that by their nature are to be satisfied at the Closing, but subject to the fulfillment or waiver of those conditions) shall be satisfied or waived in accordance with this Agreement. For purposes of this Agreement, the term "business day" shall mean any day ending at 11:59 p.m. (Eastern Time) other than a Saturday or Sunday or a day on which banks are required or authorized to close in the City of New York.

1.3. Effective Time. At the Closing, the Company and Parent will cause a certificate of merger (the "Certificate of Merger") to be executed, acknowledged and filed with the Secretary of State of the State of Delaware as provided in Section 251 of the DGCL. The Merger shall become effective at the time when the Certificate of Merger has been duly filed with the Secretary of State of the State of Delaware or at such later time as may be agreed by the parties in writing and specified in the Certificate of Merger (the "Effective Time").

ARTICLE II

Certificate of Incorporation and Bylaws of the Surviving Corporation

2.1. The Certificate of Incorporation. At the Effective Time, the certificate of incorporation of the Surviving Corporation (the "Charter") shall be amended in its entirety to read as set forth in Exhibit A hereto, until thereafter amended as provided therein or by applicable Law.

2.2. The Bylaws. The parties hereto shall take all actions necessary so that the bylaws of the Company in effect immediately prior to the Effective Time shall be the bylaws of the Surviving Corporation (the "Bylaws"), until thereafter amended as provided therein or by applicable Law.

ARTICLE III

Directors and Officers of the Surviving Corporation

3.1. Directors. The parties hereto shall take all actions necessary so that the board of directors of Merger Sub at the Effective Time shall, from and after the Effective Time, consist of the directors of the Surviving Corporation until their successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the Charter and the Bylaws.

3.2. Officers. The officers of the Company at the Effective Time shall, from and after the Effective Time, be the officers of the Surviving Corporation until their successors shall have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the Charter and Bylaws.

ARTICLE IV

Effect of the Merger on Capital Stock; Exchange of Certificates

4.1. Effect on Capital Stock. At the Effective Time, as a result of the Merger and without any action on the part of the holder of any capital stock of the Company or the sole stockholder of Merger Sub:

(a) Merger Consideration. Each share of the common stock, par value \$0.01 per share, of the Company (a "Share" or, collectively, the "Shares") issued and outstanding immediately prior to the Effective Time other than (i) Shares owned by Parent, Merger Sub or any other direct or indirect wholly-owned Subsidiary of Parent and Shares owned by the Company or any direct or indirect wholly-owned Subsidiary of the Company, and in each case not held on behalf of third parties (but not including Shares held by the Company in any "rabbi trust" or similar arrangement in respect of any compensation plan or arrangement) and (ii) Shares that are owned by stockholders ("Dissenting Stockholders") who have perfected and not withdrawn a demand for appraisal rights pursuant to Section 262 of the DGCL (each Share referred to in clause (i) or clause (ii) being an "Excluded Share" and collectively, "Excluded Shares") shall be converted into the right to receive \$27.25 per Share in cash, without interest (the "Per Share Merger Consideration"). At the Effective Time, all of the Shares shall cease to be outstanding, shall be cancelled and shall cease to exist, and each certificate (a "Certificate") formerly representing any of the Shares (other than Excluded Shares) and each non-certificated Share represented by book-entry (a "Book Entry Share") (other than Excluded Shares) shall thereafter represent only the right to receive the Per Share Merger Consideration, without interest, and each Certificate formerly representing Shares or Book Entry Shares owned by Dissenting Stockholders shall thereafter only represent the right to receive the payment to which reference is made in Section 4.2(f).

(b) Cancellation of Excluded Shares. Each Excluded Share shall, by virtue of the Merger and without any action on the part of the holder thereof, cease to be outstanding, shall be cancelled without payment of any consideration therefor and shall cease to exist, subject to any rights the holder thereof may have under Section 4.2(f).

(c) Merger Sub. At the Effective Time, each share of common stock, par value $0.01 per share, of Merger Sub issued and outstanding immediately prior to the Effective Time shall be converted into one share of common stock, par value $0.01 per share, of the Surviving Corporation.

(d) Nonvoting Preferred Stock. Each share of Nonvoting Preferred Stock issued and outstanding at the Effective Time shall remain outstanding following the Effective Time.

4.2. Exchange of Shares.

(a) Paying Agent. Immediately prior to the Effective Time, Parent shall deposit, or shall cause to be deposited, with a paying agent selected by Parent with the Company's prior approval (such approval not to be unreasonably withheld or delayed) (the "Paying Agent"), for the benefit of the holders of Shares, a cash amount in immediately available funds necessary for the Paying Agent to make payments under Section 4.1(a) (such cash being hereinafter referred to as the "Exchange Fund"). The Paying Agent agreement pursuant to which Parent shall appoint the Paying Agent shall be in form and substance reasonably acceptable to the Company. The Paying Agent shall invest the Exchange Fund as directed by Parent; provided that such investments shall be in obligations of or guaranteed by the United States of America, in commercial paper obligations rated A-1 or P-1 or better by Moody's Investors Service, Inc. or Standard & Poor's, respectively, in certificates of deposit, bank repurchase agreements or banker's acceptances of commercial banks with capital exceeding $1 billion, or in money market funds having a rating in the highest investment category granted by a recognized credit rating agency at the time of investment. Any interest and other income resulting from such investment shall become a part of the Exchange Fund, and any amounts in excess of the amounts payable under Section 4.1(a) shall be promptly returned to the Surviving Corporation. To the extent that there are any losses with respect to any such investments, or the Exchange Fund diminishes for any reason below the level required for the Paying Agent to make prompt cash payment under Section 4.1(a), Parent shall, or shall cause the Surviving Corporation to, promptly replace or restore the cash in the Exchange Fund so as to ensure that the Exchange Fund is at all times maintained at a level sufficient for the Paying Agent to make such payments under Section 4.1(a).

(b) Exchange Procedures. (i) Promptly after the Effective Time (and in any event within two business days), the Surviving Corporation shall cause the Paying Agent to mail to each holder of record of a Certificate representing Shares (other than holders of Excluded Shares) (A) a letter of transmittal in customary form specifying that delivery shall be effected, and risk of loss and title to the Certificates shall pass, only upon delivery of the Certificates (or affidavits of loss in lieu thereof as provided in

Section 4.2(e)) to the Paying Agent, such letter of transmittal to be in such form and have such other provisions as Parent and the Company may reasonably agree, and (B) instructions for use in effecting the surrender of the Certificates (or affidavits of loss in lieu thereof as provided in Section 4.2(e)) in exchange for the Per Share Merger Consideration. Upon surrender of a Certificate (or affidavit of loss in lieu thereof as provided in Section 4.2(e)) to the Paying Agent in accordance with the terms of such letter of transmittal, duly executed, the holder of such Certificate shall be entitled to receive in exchange therefor a cash amount in immediately available funds (after giving effect to any required Tax withholdings as provided in Section 4.2(g)) equal to (x) the number of Shares represented by such Certificate (or affidavit of loss in lieu thereof as provided in Section 4.2(e)) multiplied by (y) the Per Share Merger Consideration, and the Certificate so surrendered shall forthwith be cancelled. No interest will be paid or accrued on any amount payable upon due surrender of the Certificates. In the event of a transfer of ownership of Shares that is not registered in the transfer records of the Company, a check for any cash to be exchanged upon due surrender of the Certificate may be issued to such transferee if the Certificate formerly representing such Shares is presented to the Paying Agent, accompanied by all documents reasonably required to evidence and effect such transfer and to evidence that any applicable stock transfer taxes have been paid or are not applicable.

(ii) Notwithstanding anything to the contrary in this Agreement, any holder of Book Entry Shares shall not be required to deliver a Certificate or an executed letter of transmittal to the Paying Agent to receive the Per Share Merger Consideration that such holder is entitled to receive pursuant to this Article IV. In lieu thereof, each holder of record of one or more Book Entry Shares whose Shares were converted into the right to receive the Per Share Merger Consideration shall upon receipt by the Paying Agent of an "agent's message" in customary form (or such other evidence, if any, as the Paying Agent may reasonably request), be entitled to receive, and Parent shall cause the Paying Agent to pay and deliver as promptly as reasonably practicable after the Effective Time, the Per Share Merger Consideration in respect of each such Share and the Book Entry Shares of such holder shall forthwith be cancelled.

(c) Transfers. From and after the Effective Time, there shall be no transfers on the stock transfer books of the Company of the Shares that were outstanding immediately prior to the Effective Time. If, after the Effective Time, any Certificate or Book Entry Share is presented to the Surviving Corporation, Parent or the Paying Agent for transfer, it shall be cancelled and exchanged for the cash amount in immediately available funds to which the holder thereof is entitled pursuant to this Article IV.

(d) Termination of Exchange Fund. Any portion of the Exchange Fund (including the proceeds of any investments thereof) that remains unclaimed by the stockholders of the Company 180 days after the Effective Time shall be delivered to the Surviving Corporation. Any holder of Shares (other than Excluded Shares) who has not theretofore complied with this Article IV shall thereafter look only to the Surviving Corporation for payment of the Per Share Merger Consideration (after giving effect to any required Tax withholdings as provided in Section 4.2(g)) upon due surrender of its Certificates (or affidavits of loss in lieu thereof as provided in Section 4.2(e)) or Book Entry Shares, without any interest thereon. Notwithstanding the foregoing, none of the Surviving Corporation, Parent, the Paying Agent or any other Person shall be liable to any former holder of Shares for any amount properly delivered to a public official pursuant to applicable abandoned property, escheat or similar Laws. For the purposes of this Agreement, the term "Person" shall mean any individual, corporation (including not-for-profit), general or limited partnership, limited liability company, joint venture, estate, trust, association, organization, Governmental Entity or other entity of any kind or nature.

(e) Lost, Stolen or Destroyed Certificates. In the event any Certificate shall have been lost, stolen or destroyed, upon the making of an affidavit of that fact by the Person claiming such Certificate to be lost, stolen or destroyed and, if required by Parent, the posting by such Person of a bond in customary amount and upon such terms as may be required by Parent as indemnity against any claim that may be made against it or the Surviving Corporation with respect to such Certificate, the Paying Agent will issue a check in the amount (after giving effect to any required Tax withholdings as provided in Section 4.2(g)) equal to (i) the number of Shares represented by such lost, stolen or destroyed Certificate multiplied by (ii) the Per Share Merger Consideration.

(f) Appraisal Rights. No Person who has perfected a demand for appraisal rights pursuant to Section 262 of the DGCL shall be entitled to receive the Per Share Merger Consideration with respect to the Shares owned by such Person unless and until such Person shall have effectively withdrawn or lost such Person's right to appraisal under the DGCL. Each Dissenting Stockholder shall be entitled to receive only the payment provided by Section 262 of the DGCL with respect to Shares owned by such Dissenting Stockholder. The Company shall give Parent (i) prompt notice of any demands for appraisal, threatened demands for appraisal, attempted withdrawals of such demands, and any other instruments that are received by the Company relating to stockholders' rights of appraisal (any of the foregoing, a "Demand") and (ii) the opportunity to participate in and control all negotiations and proceedings with respect to any Demand. The Company shall not, except with the prior written consent of Parent, voluntarily make any payment with respect to any Demand, offer to settle or settle any such Demand.

(g) Withholding Rights. Each of the Company, Parent, the Surviving Corporation and the Paying Agent shall be entitled to deduct and withhold from the consideration otherwise payable pursuant to this Agreement to any holder of Shares, Company RSUs, Company PSUs and Company Awards (each as defined in Section 4.3) such amounts as it is required to deduct and withhold with respect to the making of such payment under the Internal Revenue Code of 1986, as amended (the "Code") or any other applicable state, local or foreign Tax Law. To the extent that amounts are so withheld by the Company, the Surviving Corporation, Parent or the Paying Agent, as the case may be, such withheld amounts (i) shall be remitted by the Company, Parent, the Surviving Corporation or the Paying Agent, as applicable, to the applicable Governmental Entity, and (ii) shall be treated for all purposes of this Agreement as having been paid to the holder of Shares in respect of which such deduction and withholding was made by the Company, the Surviving Corporation, Parent or the Paying Agent, as the case may be.

4.3. Treatment of Stock Plans.

(a) Company Restricted Stock Units. At the Effective Time, each outstanding Company restricted stock unit that vests based solely on continued service to the Company and its Subsidiaries (a "Company RSU") under the Stock Plans (as defined in Section 5.1(b)), vested or unvested, shall be cancelled and converted into the right of the holder thereof to receive, as soon as reasonably practicable (but no later than three business days) after the Effective Time (or, to the extent such Company RSU is deferred compensation subject to Section 409A of the Code, at the earliest time permitted under the applicable Stock Plan or Benefit Plan that will not trigger a tax or penalty under Section 409A of the Code, with interest at the U.S. prime rate as shown at the end of the day on Bloomberg screen BTMM or PRIME INDEX HP, whichever is higher (the "Interest Rate") from the Closing Date through such payment date), an amount in cash equal to the product of (x) the total number of Shares subject to such Company RSU immediately prior to the Effective Time, multiplied by (y) the Per Share Merger Consideration; provided, however, that any Company RSUs granted after the date hereof will only payout on a prorated basis based on the number of days elapsed from the grant date (or, in the case of the annual 2015 grants, January 1, 2015) through the Closing Date relative to 1,095 days (and the remainder of such awards will be cancelled without payment).

(b) Company Performance Stock Units. At the Effective Time, each outstanding Company restricted stock unit that vests, in whole or in part, based on the achievement of performance objectives (a "Company PSU") under the Stock Plans, vested or unvested, shall be cancelled and converted into the right of the holder thereof to receive, as soon as reasonably practicable (but no later than three business days) after the Effective Time (or, to the extent such Company PSU is deferred compensation subject to Section 409A of the Code, at the earliest time permitted under the applicable Stock Plan or Benefit Plan that will not trigger a tax or penalty under Section 409A of the Code, with interest at the Interest Rate from the Closing Date through such payment date), an amount in cash equal to the product of (x) the total number of Shares subject to such Company PSU immediately prior to the Effective Time, determined (without proration) based on achievement of applicable performance objectives at the greater of (1) actual performance as reasonably determined by the compensation committee of the board of directors of the Company prior to the Effective Time based on performance through a day that is no more than five business days prior to the Effective Time and (2) the target level of 100%, multiplied by (y) the Per Share Merger Consideration; provided, however, that any Company PSUs granted after the date hereof will have performance determined based on the greater of (1) actual performance (determined as described above) and (2) the target level of 100%, and will only payout on a prorated basis based on the number of days elapsed from the grant date (or, in the case of the annual 2015 grants, January 1, 2015) through the Closing Date relative to 1,095 days (and the remainder of such awards will be cancelled without payment).

(c) Company Awards. At the Effective Time, each right of any kind, contingent or accrued, vested or unvested, to acquire or receive Shares or benefits measured by the value of Shares, and each award of any kind consisting of Shares that may be held, awarded, outstanding, payable or reserved for issuance under the Stock Plans and any other Benefit Plans, other than Company RSUs and Company PSUs (the "Company Awards"), shall be cancelled and shall only entitle the holder thereof to receive, as soon as reasonably practicable after the Effective Time (or, to the extent such Company Award is deferred compensation subject to Section 409A of the Code, at the earliest time permitted under the applicable Stock Plan or Benefit Plan that will not trigger a tax or penalty under Section 409A of the Code, with interest at the Interest Rate from the Closing Date through such payment date), an amount in cash equal to (x) the number of Shares subject to such Company Award immediately prior to the Effective Time determined (without proration) based on achievement of any applicable performance objectives at the greater of (1) actual performance as reasonably determined by the compensation committee of the board of directors of the Company prior to the Effective Time based on performance through a day that is no more than five business days prior to the Effective Time and (2) the target level of 100%, multiplied by (y) the Per Share Merger Consideration (or, if the Company Award provides for payments to the extent the value of the Shares exceeds a specified reference or exercise price, the amount, if any (or zero, if no such excess), by which the Per Share Merger Consideration exceeds such reference or exercise price).

(d) Corporate Actions. At or prior to the Effective Time, the Company, the board of directors of the Company and the compensation committee of the board of directors of the Company, as applicable, shall adopt any resolutions and take any actions which are necessary to effectuate the provisions of Sections 4.3(a) through 4.3(c).

4.4. Adjustments to Prevent Dilution. In the event that the Company changes the number of Shares or securities convertible or exchangeable into or exercisable for Shares issued and outstanding prior to the Effective Time as a result of a reclassification, stock split (including a reverse stock split), stock dividend or distribution, recapitalization, merger, issuer tender or exchange offer, or other similar transaction, the Per Share Merger Consideration shall be equitably adjusted.

ARTICLE V

Representations and Warranties

5.1. Representations and Warranties of the Company. Except as set forth in (x) the Company Reports filed with or furnished to the Securities and Exchange Commission (the "SEC") by the Company on or after January 1, 2012 and prior to the date hereof (excluding any disclosures of information, factors or risks contained or referenced therein under the captions "Risk Factors," "Forward-Looking Statements," or "Quantitative and Qualitative Disclosures About Market Risk," to the extent they are statements that are predictive, cautionary or forward-looking in nature, and provided that nothing in the Company Reports shall be deemed to modify or qualify the representations and warranties set forth in Sections 5.1(a) (Organization, Good Standing and Qualification), 5.1(b) (Capital Structure), Section 5.1(c) (Corporate Authority; Approval and Fairness), 5.1(l) (Takeover Statutes) or 5.1(s) (Brokers and Finders), or (y) the corresponding sections or subsections of the disclosure letter delivered to Parent by the Company prior to entering into this Agreement (the "Company Disclosure Letter") (it being agreed that disclosure of any item in any section or subsection of the Company Disclosure Letter shall be deemed disclosure with respect to any other section or subsection to which the relevance of such item is reasonably apparent), the Company hereby represents and warrants to Parent and Merger Sub that:

(a) Organization, Good Standing and Qualification. Each of the Company and its Subsidiaries is a legal entity duly organized, validly existing and in good standing under the Laws of its respective jurisdiction of organization and has all requisite corporate or similar power and authority to own, lease and operate its properties and assets and to carry on its business as presently conducted and is qualified to do business and is in good standing as a foreign corporation or similar entity in each jurisdiction where the ownership, leasing or operation of its assets or properties or conduct of its business requires such qualification, except where the failure to be so organized, qualified or in good standing, or to have such power or authority, are not, individually or in the aggregate, reasonably likely to have a Company Material Adverse Effect. The Company has made available to Parent complete and correct copies of the Company's and its Significant Subsidiaries' certificates of incorporation and bylaws or comparable governing documents, each as amended to the date hereof, and each as so made available is in effect on the date hereof.

As used in this Agreement, the term (i) "Subsidiary" means, with respect to any Person, any other Person of which at least a majority of the securities or ownership interests having by their terms ordinary voting power to elect a majority of the board of directors or other persons performing similar functions is directly or indirectly owned or controlled by such Person and/or by one or more of its Subsidiaries; (ii) "Significant Subsidiary" has the meaning set forth in Rule 1.02(w) of Regulation S-X under the Securities Exchange Act of 1934, as amended (the "Exchange Act"); (iii) "Affiliate" means, with respect to any Person, any other Person, directly or indirectly, controlling, controlled by, or under common control with, such Person. For purposes of this definition, the term "control" (including the correlative terms "controlling," "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise; and (iv) "Company Material Adverse Effect" means any change, event, occurrence or effect that, individually or taken together with other changes, events, occurrences or effects, has a material adverse effect on the financial condition, business or results of operations of the Company and its Subsidiaries, taken as a whole; provided, however, that none of the following shall constitute or be taken into account in determining whether there is or, where applicable, has been a Company Material Adverse Effect:

(A) changes in general economic or political conditions or the securities, credit, commodities or financial markets in general in the United States or the geographic area within which PJM Interconnection, LLC ("PJM") operates as a regional transmission organization (the "PJM Region"), or the Mid-Atlantic Area Council within the PJM Region;

(B) (i) acts of war or terrorism or (ii) changes, events, circumstances or developments that are weather-related or result from any natural disasters, "acts of God" or other "force majeure" events;

(C) any adoption, implementation, promulgation, repeal, modification, reinterpretation or proposal of any rule, regulation, ordinance, order, protocol or any other Law of or by any national, regional, state or local Governmental Entity or of or by the North American Electric Reliability Corporation ("NERC") or PJM;

(D) changes, events or developments in the (x) electric generating, transmission or distribution industries or natural gas transmission or distribution industries (including any changes in the operations thereof), (y) engineering or construction industries, or (z) wholesale or retail markets for commodities, materials or supplies (including equipment supplies, steel, concrete, electric power, fuel, coal, natural gas, water or coal transportation) or the hedging markets therefor;

(E) changes or developments in wholesale or retail electric power prices;

(F) system-wide changes or developments in electric transmission or distribution systems (other than changes solely affecting the Company or any of its Subsidiaries);

(G) any changes in customer usage patterns or customer selection of third-party suppliers for electricity;

(H) any loss or overtly threatened loss, or adverse change or overtly threatened adverse change, in the relationship of the Company or any of its Subsidiaries with its customers, employees, regulators, financing sources, labor unions or suppliers caused by the pendency or the announcement of the transactions contemplated by this Agreement;

(I) changes or effects from the entry into, the announcement or pendency of, or the performance of obligations required by this Agreement or consented to or requested by Parent or Merger Sub, including any change resulting from a failure to file rate cases as planned or to receive orders from State Commissions approving rate increases as contemplated by the Company's financial plans, any change in the Company's credit ratings and any actions taken by the Company and its Subsidiaries that is expressly permitted or required pursuant to this Agreement or is consented to or requested by Parent to obtain approval from any Governmental Entity for consummation of the Merger (including (i) any actions taken by Parent, the Company or any of their respective Subsidiaries to settle the Rate Cases as permitted by Section 6.5(f), (ii) any actions required to be taken by Parent, the Company or any of their respective Affiliates to obtain any Parent Approval or any Company Approval, (iii) any action by any Governmental Entity that requires Parent or the Company or any of their respective Subsidiaries or Affiliates to accept the commitments and agreements set forth in Exhibit B hereto (the "Regulatory Commitments"), (iv) the issuance, sale and delivery of the Nonvoting Preferred Stock to Parent pursuant to the Subscription Agreement and (v) any agreements consented to by Parent to obtain the Regulatory Approvals, including to implement the Regulatory Commitments);

(J) changes in GAAP or interpretation thereof after the date hereof;

(K) any failure by the Company to meet any internal or public projections or forecasts or estimates of revenues or earnings for any period ending on or after the date of this Agreement, provided that the exception in this clause shall not prevent or otherwise affect a determination that any change, event, occurrence, effect, circumstance or development underlying such failure has resulted in, or contributed to, a Company Material Adverse Effect;

(L) changes that arise out of or relate to the identity of Parent or any of its Affiliates as the acquirer of the Company;

(M) a decline in the price or trading volume of the Company common stock on the New York Stock Exchange (the "NYSE") on or after the date of this Agreement, provided that the exception in this clause shall not prevent or otherwise affect a determination that any change, event, occurrence, effect, circumstance or development underlying such decline has resulted in, or contributed to, a Company Material Adverse Effect; and

(N) changes that result from any shutdown or suspension of operations at the power plants from which the Company obtains electricity or facilities from which the Company obtains natural gas;

provided, further, however, that matters, changes, events, occurrences, effects or developments set forth in clauses (A), (B), (C), (D), (E), (F), and (G), above may be taken into account in determining whether there has been or is a Company Material Adverse Effect to the extent such matters, changes, events, occurrences, effects or developments have a materially disproportionate adverse effect on the Company and its Subsidiaries, taken as a whole, as compared to other entities (if any) engaged in the relevant business in the geographic area affected by such matters, changes, events, occurrences, effects or developments.

(b) Capital Structure. The authorized capital stock of the Company consists of 400,000,000 Shares, of which 251,025,051 Shares were outstanding as of the close of business on April 28, 2014 and 40,000,000 shares of preferred stock, par value $0.01 per share, none of which are outstanding as of the close of business on April 28, 2014, of which 9,000 shares of Nonvoting Preferred Stock are to be authorized, issued and outstanding pursuant to the Subscription Agreement on the Initial Closing Date (as such term is defined in the Subscription Agreement). All of the outstanding Shares have been duly authorized and are validly issued, fully paid and nonassessable. When issued pursuant to the Subscription Agreement, the shares of Nonvoting Preferred Stock issued to Parent will be validly issued, fully paid and nonassessable. As of April 28, 2014, other than 774,201 Shares reserved for issuance in respect of Company RSUs, 2,468,233 Shares reserved for issuance in respect of Company PSUs, and 5,725,564 Shares reserved for issuance under the Direct Stock Purchase and Dividend Reinvestment Plan, and 20,143,400 Shares reserved for issuance in respect of Company Awards under the Pepco Holdings, Inc. Long-Term Incentive Plan, the Pepco Holdings, Inc. 2012 Long-Term Incentive Plan, the Pepco Holdings, Inc. Non-Management Directors Compensation Plan, and the Pepco Holdings, Inc. Retirement Savings Plan (collectively, the "Stock Plans"), the Company has no Shares reserved for issuance. Each of the outstanding shares of capital stock or other equity securities of each of the Company's Subsidiaries is duly authorized, validly issued, fully paid and nonassessable and owned by the Company or by a direct or indirect wholly-owned Subsidiary of the Company, free and clear of any lien, charge, pledge, security interest, claim, or other encumbrance (each, a "Lien"). Except as set forth above, there are no preemptive or other outstanding rights, options, warrants, conversion rights, stock appreciation rights, performance units, redemption rights, repurchase rights, agreements, arrangements, calls, commitments or rights of any kind that obligate the Company or any of its Subsidiaries to issue or sell any shares of capital stock or other equity securities of the Company or any of its Subsidiaries or any securities or obligations convertible or exchangeable into or exercisable for, or giving any Person a right to subscribe for or acquire, any equity securities of the Company or any of its Subsidiaries, and no securities or obligations evidencing such rights are authorized, issued or outstanding. Upon any issuance of any Shares in accordance with the terms of the Stock Plans, such Shares will be duly authorized, validly issued, fully paid and nonassessable and free and clear of any Liens. The Company does not have outstanding any bonds, debentures, notes or other obligations the holders of which have the right to vote (or convertible into or exercisable for securities having the right to vote) with the stockholders of the Company on any matter. For purposes of this Agreement, a wholly-owned Subsidiary of the Company shall include any Subsidiary of the Company of which all of the shares of capital stock of such Subsidiary are owned by the Company (or a wholly-owned Subsidiary of the Company).

(c) Corporate Authority; Approval and Fairness.

(i) The Company has all requisite corporate power and authority and has taken all corporate action necessary in order to execute and deliver this Agreement and, subject only to adoption of this Agreement by the holders of a majority of the outstanding Shares entitled to vote on such matter at a stockholders' meeting duly called and held for such purpose (the "Company Requisite Vote"), to perform its obligations under this Agreement and to consummate the Merger. This Agreement has been duly executed and delivered by the Company and constitutes a valid and binding agreement of the Company enforceable against the Company in accordance with its terms, subject to bankruptcy, insolvency, fraudulent transfer, reorganization, moratorium and similar Laws of general applicability relating to or affecting creditors' rights and to general equity principles (the "Bankruptcy and Equity Exception").

(ii) The board of directors of the Company has (A) unanimously determined that the Merger is in the best interests of the Company and its stockholders, approved and declared advisable this Agreement and the Merger and resolved to recommend adoption of this Agreement to the holders of Shares (the "Company Recommendation"), (B) directed that this Agreement be submitted to the holders of Shares for their adoption and (C) received the opinion of its financial advisors, Lazard Frères & Co. LLC and Morgan Stanley & Co. LLC, to the effect that the Per Share Merger Consideration to be received by the holders of Shares in the Merger is fair from a financial point of view, as of the date of such opinions, to such holders. It is agreed and understood that such opinions are for the benefit of the Company's board of directors and may not be relied on by Parent or Merger Sub. The board of directors of the Company has taken all action so that Parent will not be an "interested stockholder" or prohibited from entering into or consummating a "business combination" with the Company (in each case as such term is used in Section 203 of the DGCL) as a result of the execution of this Agreement or the consummation of the transactions in the manner contemplated hereby.

(d) Governmental Filings and Approvals; No Violations; Certain Contracts.

(i) Other than the filings, approvals and/or notices (A) pursuant to Section 1.3, (B) under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act"), (C) under the Exchange Act, (D) under stock exchange rules, (E) with the Federal Energy Regulatory Commission (the "FERC") under the Federal Power Act (the "FERC Approval"), (F) with the Federal Communications Commission (the "FCC") (the "FCC Approval"), (G) with the Delaware Public Service Commission, the District of Columbia Public Service Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities, the Virginia State Corporation Commission (collectively, the "State Commissions") under applicable state Laws (the "State Approvals") and (H) the filings, approvals and/or notices listed in Section 5.1(d)(i) of the Company Disclosure Letter (together with the other approvals referred to in clauses (B) through (G) of this Section 5.1(d)(i), the "Company Approvals"), no notices, reports or other filings are required to be made by the Company or any of its Subsidiaries with, nor are any consents, registrations, approvals, permits or authorizations required to be obtained by the Company from, any domestic or foreign governmental or regulatory authority, agency, commission, body, court or other legislative, executive or judicial governmental entity (each, a "Governmental Entity"), NERC or PJM, in connection with the execution, delivery and performance of this Agreement by the Company and the consummation of the Merger, except those, the failure to make or obtain are not, individually or in the aggregate, reasonably likely to have a Company Material Adverse Effect or prevent, materially delay or materially impair the consummation of the Merger.

(ii) The execution, delivery and performance of this Agreement by the Company do not, and the consummation of the Merger will not, constitute or result in (A) a breach or violation of, or a default under, the certificate of incorporation or bylaws of the Company or the comparable governing documents of any of its Subsidiaries, (B) with or without notice, lapse of time or both, a breach or violation of, a termination (or right of termination) or a default under, the creation or acceleration of any obligations under, or the creation of a Lien on any of the assets of the Company or any of its Subsidiaries pursuant to, any agreement, lease, license, contract, note, mortgage, indenture, arrangement or other obligation (each, a "Contract") not otherwise terminable by the other party thereto on 90 days' or less notice without penalty, binding upon the Company or any of its Subsidiaries or (C) assuming compliance with the matters referred to in Section 5.1(d)(i), a violation of any Law to which the Company or any of its Subsidiaries is subject, except, in the case of clause (B) or (C) of this Section 5.1(d)(i), for any such breach, violation, termination, default, creation, acceleration or change that, individually or in the aggregate, is not reasonably likely to have a Company Material Adverse Effect or prevent, materially delay or materially impair the consummation of the Merger.

(e) Company Reports; Financial Statements.

(i) The Company has filed or furnished, as applicable, on a timely basis, all forms, statements, certifications, reports and documents required to be filed or furnished by it with the SEC pursuant to the Exchange Act or the Securities Act of 1933, as amended (the "Securities Act"), since December 31, 2011 (the "Applicable Date") (the forms, statements, certifications, reports and documents filed or furnished since the Applicable Date and those filed or furnished subsequent to the date hereof, including any amendments thereto, the "Company Reports"). Each of the Company Reports, at the time of its filing or being furnished complied or, if not yet filed or furnished, will comply in all material respects with the applicable requirements of the Securities Act and the Exchange Act and any rules and regulations promulgated thereunder applicable to the Company Reports. As of their respective dates (or, if amended prior to the date hereof, as of the date of such amendment), the Company Reports did not, and any Company Reports filed with or furnished to the SEC subsequent to the date hereof will not, contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements made therein, in light of the circumstances in which they were made, not misleading.

(ii) The Company is in compliance in all material respects with the applicable listing and corporate governance rules and regulations of the NYSE.

(iii) Each of the consolidated balance sheets included in or incorporated by reference into the Company Reports (including the related notes and schedules) fairly presents in all material respects, or, in the case of Company Reports filed after the date hereof, will fairly present in all material respects the consolidated financial position of the Company and its consolidated Subsidiaries as of its date and each of the consolidated statements of (loss) income, comprehensive (loss) income, cash flows and equity included in or incorporated by reference into the Company Reports (including any related notes and schedules) fairly presents in all material respects, or, in the case of Company Reports filed after the date hereof, will fairly present in all material respects, the financial position, results of operations and cash flows, as the case may be, of the Company and its consolidated Subsidiaries for the periods set forth therein (subject, in the case of unaudited statements, to notes and year-end adjustments), in each case in accordance with U.S. generally accepted accounting principles ("GAAP") applied consistently during the periods presented, except as may be noted therein.

(iv) The Company maintains internal control over financial reporting (as defined in Rule 13a-15 or 15d-15, as applicable, under the Exchange Act). Such internal control over financial reporting is effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP in all material respects. Except as has not had, and would not be reasonably likely to have, individually or in the aggregate, a Company Material Adverse Effect, (A) the Company maintains disclosure controls and procedures required by Rule 13a-15 or 15d-15 under the Exchange Act that are effective to ensure that information required to be disclosed by the Company is recorded and reported on a timely basis to the individuals responsible for the preparation of the Company's filings with the SEC and other public disclosure documents and (B) the Company has disclosed, based on its most recent evaluation prior to the date of this Agreement, to the Company's outside auditors and the audit committee of the board of directors of the Company (1) any significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information and (2) any fraud, known to the Company, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

(f) Absence of Certain Changes. Since December 31, 2013, the Company and its Subsidiaries have conducted their respective businesses only in, and have not engaged in any material transaction other than according to, the ordinary and usual course of such businesses and there has not been:

(i) any change, event, occurrence or effect in the financial condition, business or results of operations that, individually or in the aggregate, has had or is reasonably likely to have, a Company Material Adverse Effect;

(ii) any material damage, destruction or other casualty loss with respect to any material asset or property owned, leased or otherwise used by the Company or any of its Subsidiaries, whether or not covered by insurance that, individually or in the aggregate, has had or is reasonably likely to have, a Company Material Adverse Effect;

(iii) other than regular quarterly dividends on Shares, any declaration, setting aside or payment of any dividend or other distribution with respect to any shares of capital stock of the Company or any of its Subsidiaries (except for dividends or other distributions by any direct or indirect wholly-owned Subsidiary to the Company or to any other wholly-owned Subsidiary of the Company);

(iv) any material change in any method of accounting or accounting practice by the Company or any of its Subsidiaries; or

(v) any action taken that, if taken after the date of this Agreement without Parent's consent, would constitute a breach of the covenants set forth in clauses (v), (vii), (viii) or (xiv) of Section 6.1.

(g) Litigation and Liabilities.

(i) There are no civil, criminal or administrative actions, suits, claims, hearings, arbitrations, investigations or other proceedings pending or, to the Knowledge of the Company, threatened against the Company or any of its Subsidiaries that, individually or in the aggregate, has or are reasonably likely to have a Company Material Adverse Effect. Neither the Company nor any of its Subsidiaries is a party to or subject to the provisions of any judgment, order, settlement, writ, injunction, decree or award of any Governmental Entity specifically imposed upon the Company or any of its Subsidiaries which, individually or in the aggregate, has or is reasonably likely to have a Company Material Adverse Effect.

(ii) Neither the Company nor any of its Subsidiaries has any liabilities or obligations of any nature (whether accrued, absolute, contingent or otherwise) required by GAAP to be set forth on a consolidated balance sheet of the Company and its Subsidiaries, other than liabilities and obligations (A) set forth in the Company's consolidated balance sheet (and the notes thereto) included in the Company Reports filed prior to the date of this Agreement, (B) incurred in the ordinary course of business since December 31, 2013, (C) incurred in connection with the Merger or any other transaction or agreement contemplated by this Agreement, or (D) that are not, individually or in the aggregate, reasonably likely to have a Company Material Adverse Effect.

The term "Knowledge" when used in this Agreement with respect to the Company shall mean the actual knowledge of those persons set forth in Section 5.1(g) of the Company Disclosure Letter.

(h) Employee Benefits.

(i) All material benefit and compensation plans, contracts (including employment and consulting contracts), policies or arrangements covering current or former employees, directors or other individual service providers of the Company and its Subsidiaries that are maintained, sponsored or administered by the Company or its Subsidiaries, under which the Company or its Subsidiaries is subject to continuing financial obligations or with respect to which the Company or its Subsidiaries could reasonably be expected to incur any liability, including, but not limited to, "employee benefit plans" within the meaning of Section 3(3) of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), and deferred compensation, severance, pension, retirement, bonus, health and welfare, stock option, stock purchase, stock appreciation rights, stock based, and incentive plans (whether or not material, the "Benefit Plans") are listed on Section 5.1(h)(i) of the Company Disclosure Letter. True and complete copies of all Benefit Plans listed on Section 5.1(h)(i) of the Company Disclosure Letter and, as applicable, the most recent actuarial valuation and audit reports, and the IRS determination letter currently in effect have been made available to Parent.

(ii) All Benefit Plans, other than "multiemployer plans" within the meaning of Section 3(37) of ERISA (each, a "Multiemployer Plan") have been established, maintained, funded and administered and are in compliance with their terms, the terms of any applicable collective bargaining agreement, ERISA, the Code and other applicable Laws, except as would not, individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect. No Benefit Plan is a Multiemployer Plan. Each Benefit Plan (other than any Multiemployer Plan) which is subject to ERISA (an "ERISA Plan") that is an "employee pension benefit plan" within the meaning of Section 3(2) of ERISA intended to be qualified under Section 401(a) of the Code, has received a favorable determination or opinion letter from the Internal Revenue Service (the "IRS") or has applied to the IRS for such favorable determination or opinion letter under Section 401(b) of the Code. To the Knowledge of the Company, neither the Company nor any of its Subsidiaries nor any other Person has engaged in a transaction with respect to any ERISA Plan that, assuming the taxable period of such transaction expired as of the date hereof, would reasonably be expected to subject the Company or any Subsidiary to a tax or penalty imposed by either

Section 4975 of the Code or Section 502(i) of ERISA in an amount which would be material.

(iii) Neither the Company nor any of its Subsidiaries has or is reasonably expected to incur any liability under Subtitle C or D of Title IV of ERISA with respect to any ongoing, frozen or terminated "single-employer plan", within the meaning of Section 4001(a)(15) of ERISA, currently or formerly maintained by any of them, or the single-employer plan of any entity which is considered one employer with the Company under Section 4001 of ERISA or Section 414 of the Code (an "ERISA Affiliate"), except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company and its Subsidiaries have not incurred and do not expect to incur any withdrawal liability with respect to a Multiemployer Plan under Subtitle E of Title IV of ERISA (regardless of whether based on contributions of an ERISA Affiliate) that has not been satisfied, except as would not reasonably be expected, individually or in the aggregate, to have a Company Material Adverse Effect.

(iv) There are no pending or, to the Knowledge of the Company threatened, claims, audits, investigations, proceedings or litigation relating to the Benefit Plans, other than routine claims for benefits, except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Other than pursuant to an existing collective bargaining or similar agreement between the Company and any labor union, neither the Company nor any of its Subsidiaries has any obligations for retiree health and life benefits under any ERISA Plan.

(v) Neither the execution of this Agreement, the approval of the Merger by the stockholders of the Company nor the consummation of the Merger will (A) entitle any Designated Officer to severance pay or any material increase in severance pay upon any termination of employment after the date hereof (other than severance pay required by any Law) or (B) accelerate the time of payment or vesting or result in any material payment or funding (through a grantor trust or otherwise) of compensation or benefits under, increase the amount payable or result in any other material obligation pursuant to, any of the Benefit Plans.

(vi) No amount that could be received (whether in cash or property or the vesting of property), as a result of the consummation of the Merger, by any employee, director or other individual service provider of the Company or its Subsidiaries under any Benefit Plan or otherwise would not be deductible by reason of Section 280G of the Code or would be subject to an excise tax under Section 4999 of the Code, except as would not individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect. Neither the Company nor any of its Subsidiaries has any indemnity obligation on or after the Effective Time for any Taxes imposed under Section 4999 or 409A of the Code.

The term "Designated Officer" when used in this Agreement shall mean an "officer" of the Company for purposes of Rule 16a-1(f) under the Exchange Act. Section 5.1(h) of the Company Disclosure Letter contains a correct and complete list of the Designated Officers as of the date of this Agreement.

(i) Compliance with Laws; Licenses. The businesses of each of the Company and its Subsidiaries have not been since the Applicable Date, and are not being, conducted in violation of any federal, state, local or foreign law, statute or ordinance, common law, or any rule, regulation, standard, judgment, order, writ, injunction, decree, arbitration award, agency requirement, license or permit of any Governmental Entity (collectively, "Laws"), except for violations that, individually or in the aggregate, are not reasonably likely to have a Company Material Adverse Effect. Except with respect to regulatory matters covered by Section 6.5, no investigation or review by any Governmental Entity, NERC or PJM with respect to the Company or any of its Subsidiaries is pending or, to the Knowledge of the Company, threatened, nor has any Governmental Entity indicated an intention to conduct the same, except for such investigations or reviews, the outcome of which is not, individually or in the aggregate, reasonably likely to have a Company Material Adverse Effect. The Company and its Subsidiaries each has obtained and is in compliance with all permits, certifications, approvals, registrations, consents, authorizations, franchises, variances, exemptions and orders issued or granted by a Governmental Entity, NERC or PJM ("Licenses") necessary to conduct its business as presently conducted, except those the absence of which would not, individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect.

(j) Company Material Contracts. Except as has not had (since December 31, 2013) or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (i) neither the Company nor any Subsidiary of the Company is in breach of or default under the terms of any Contract that would be required to be filed by the Company as a "material contract" (as such term is defined in item 601(b)(10) of Regulation S-K of the Securities Act, except for any such Contract that is a Benefit Plan or would be a Benefit Plan but for the word "material" in the definition thereof) (each such Contract a "Company Material Contract"), (ii) as of the date hereof, to the Knowledge of the Company, no other party to any Company Material Contract is in breach of or default under the terms of any Company Material Contract and (iii) each Company Material Contract is a valid and binding obligation of the Company or its Subsidiary that is a party thereto and, to the Knowledge of the Company, is in full force and effect unless terminated in accordance with its terms.

(k) Real Property. Except as would not be reasonably expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company and its Subsidiaries have either good title, in fee or valid leasehold, easement or other rights, to the land, buildings, wires, pipes, structures and other improvements thereon and fixtures thereto, necessary to permit the Company and its Subsidiaries to conduct their business as currently conducted free and clear of any Liens.

(l) Takeover Statutes. No "fair price," "moratorium," "control share acquisition" or any anti-takeover statute or regulation (each, a "Takeover Statute") or any anti-takeover provision in the Company's certificate of incorporation or bylaws is applicable to the Company, the Shares or the Merger.

(m) Environmental Matters. Except for such matters that, individually or in the aggregate, have not had a Company Material Adverse Effect: (A) the Company and its Subsidiaries are and since the Applicable Date have been in compliance with applicable Environmental Laws; (B) the Company and its Subsidiaries possess all permits, licenses, registrations, identification numbers, authorizations and approvals required under applicable Environmental Laws for the operation of the business as presently conducted; (C) neither the Company nor any Subsidiary has received any written claim, notice of violation or citation concerning any violation or alleged violation of, or liability under, any applicable Environmental Law during the past two years which has not been fully resolved without future obligation; and (D) there are no writs, injunctions, decrees, orders or judgments outstanding, or any judicial actions, suits or proceedings pending or, to the Knowledge of the Company, threatened, concerning compliance by the Company or any Subsidiary with, or liability under, any Environmental Law; and (E) neither the Company nor any Subsidiary has any obligation or liability for the disposal, handling or release of, contamination by, or exposure of any Person to, any Hazardous Substance in violation of any Environmental Laws in the case of (A) or (B) that has given rise to liabilities under any Environmental Laws.

Notwithstanding any other representation or warranty in Article V of this Agreement, the representations and warranties contained in this Section 5.1(m) constitute the sole representations and warranties of the Company relating to any Environmental Law.

As used herein, the term "Environmental Law" means any applicable Law, regulation, code, license, permit, order, judgment, decree or injunction from any Governmental Entity concerning (A) pollution or the protection of the environment (including air, water, soil and natural resources), (B) the use, storage, handling, release or disposal of, or exposure to, Hazardous Substances or (C) public or worker health and safety as it relates to Hazardous Substance exposure, in each case in effect on or prior to Closing.

As used herein, the term "Hazardous Substance" means any substance presently listed, defined, designated or classified as hazardous, toxic, a pollutant, or radioactive under any applicable Environmental Law, including petroleum and any derivative or by-products thereof.

(n) Taxes. Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect:

(i) The Company and each of its Subsidiaries (A) have prepared in good faith and duly and timely filed (taking into account any extension of time within which to file) all Tax Returns required to be filed by any of them, and all such filed Tax Returns are true, complete and accurate; (B) have paid all Taxes that are shown as due on such filed Tax Returns or that the Company or any of its Subsidiaries are obligated to withhold from amounts owing to any employee, creditor or third party, (C) have adequate accruals and reserves, in accordance with GAAP, on the Company Reports for all Taxes payable by the Company and each of its Subsidiaries for all taxable periods and portions thereof through the date of such Company Reports; (D) have not, since the date of the Company Reports, incurred any liability for Taxes outside the ordinary course of business or otherwise inconsistent with past custom and practice (unless adequate accruals and reserves, in accordance with GAAP, have been established on the Company Reports in advance of, and with respect, to the incurrence of such liability); and (E) have not waived any statute of limitations with respect to any material amount of Taxes or agreed to any extension of time with respect to any material amount of Tax assessment or deficiency.

(ii) As of the date hereof, there are not pending or, to the Knowledge of the Company, threatened in writing, any audits (or other similar proceedings initiated by a Governmental Entity) in respect of Taxes or Tax matters to which the Company is a party.

(iii) Neither the Company nor any of its Subsidiaries is obligated by any written contract, agreement or other agreement to indemnify any other person (other than the Company and its Subsidiaries) with respect to Taxes. Neither the Company, nor any of its Subsidiaries is a party to or bound by any written Tax allocation, indemnification or sharing agreement (other than an agreement with the Company or its Subsidiaries). To the knowledge of the Company, neither the Company nor any of its Subsidiaries is liable under Treasury Regulation Section 1.1502-6 (or any similar provision of the Tax Laws of any state, local or foreign jurisdiction) or as a transferee or successor for any Tax of any person other than the Company and its Subsidiaries.

(iv) Notwithstanding any other representation or warranty in Article V of this Agreement, the representations and warranties contained in this Section 5.1(n) constitute the sole representations and warranties of the Company relating to any Tax, Tax Return or Tax matter.

As used in this Agreement, (A) the term "Tax" (including, with correlative meaning, the term "Taxes") includes all federal, state, local and foreign income, profits, franchise, gross receipts, environmental, customs duty, capital stock, severances, stamp, payroll, sales, employment, unemployment, disability, use, property, withholding, excise, production, value added, occupancy and other taxes, duties or assessments of any nature whatsoever, together with all interest, penalties and additions imposed with respect to such amounts and any interest in respect of such penalties and additions, and (B) the term "Tax Return" includes all returns and reports (including elections, declarations, disclosures, schedules, estimates and information returns) required to be supplied to a Tax authority relating to Taxes.

(o) Labor Matters. As of the date of this Agreement: (i) neither the Company nor any of its Subsidiaries is a party to or otherwise bound by any collective bargaining agreement or other Contract with a labor union or labor organization (a "CBA"), nor is the Company or any of its Subsidiaries the subject of any material proceeding asserting that the Company or any of its Subsidiaries has committed an unfair labor practice or seeking to compel it to bargain with any labor union or labor organization and (ii) there is no pending or, to the Knowledge of the Company, threatened, labor strike, dispute, walk-out, work stoppage or lockout involving the Company or any of its Subsidiaries, except in either case of clause (i) or (ii) as would not be reasonably likely to have, individually or in the aggregate, a Company Material Adverse Effect.

(p) Intellectual Property. (i) To the Knowledge of the Company, (A) the Company and its Subsidiaries have sufficient rights to use all material Intellectual Property used in its business as presently conducted, and (B) no person is violating any material Intellectual Property owned by the Company except as would not be reasonably likely to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) For purposes of this Agreement, the following term has the following meaning:

"Intellectual Property" means any intellectual property, including trademarks, service marks, Internet domain names, logos, trade dress, trade names, and all goodwill associated therewith and symbolized thereby, inventions, discoveries, patents, processes, technologies, confidential information, trade secrets, know-how, copyrights and copyrightable works, software, databases and related items.

(q) Insurance. All material fire and casualty, general liability, director and officer, business interruption, product liability, and sprinkler and water damage insurance policies maintained by the Company or any of its Subsidiaries ("Insurance Policies") are in full force and effect and all premiums due with respect to all Insurance Policies have been paid as of the date of this Agreement, with such exceptions that, individually or in the aggregate, are not reasonably likely to have a Company Material Adverse Effect.

(r) Regulatory Matters.

(i) The Company is not subject to regulation as an "electric utility" or a "gas utility", a "public utility" or "utility" under applicable state Law. Each of Atlantic City Electric Company, Delmarva Power & Light Company and Potomac Electric Power Company is a "public utility" under and as defined in the Federal Power Act and as such each is subject to regulation thereunder. Atlantic City Electric Company is also regulated as a "public utility" under New Jersey state

Law; Delmarva Power & Light Company is also regulated as a "public utility" under Delaware state Law and Virginia state Law and as an "electric company" under Maryland state Law; and Potomac Electric Power Company is also regulated as a "public utility" under the Laws of the District of Columbia, and as an "electric company" under Maryland state Law, and as a "public utility" under Virginia state Law. Pepco Energy Services is licensed as a retail electricity supplier in the jurisdictions set forth on Section 5.1(r) of the Company Disclosure Letter and is subject to the regulations generally applicable to retail electricity suppliers operating in those jurisdictions. Except for regulation of the Company and its Subsidiaries as set forth in this Section, neither the Company nor any of its Subsidiaries is subject to regulation as a public utility or public service company (or similar designation) by the FERC, any state in the United States or in any foreign nation.

(ii) Except for the Rate Cases, neither the Company nor any of its Subsidiaries (A) has rates which have been or are being collected subject to refund, pending final resolution of any proceedings pending before a Governmental Entity or on appeal to the courts, or (B) is a party (solely with respect to the business of the Company and its Subsidiaries) to any proceeding before a Governmental Entity or on appeal from orders of a Governmental Entity, in each case which individually or in the aggregate, has had or is reasonably likely to have a Company Material Adverse Effect.

(s) Brokers and Finders. Neither the Company nor any of its officers, directors or employees has employed any broker or finder or incurred any liability for any brokerage fees, commissions or finders' fees in connection with the Merger other than Lazard Frères & Co. LLC and Morgan Stanley & Co. LLC.

5.2. Representations and Warranties of Parent and Merger Sub. Except as set forth in any forms, statements, certifications, reports or documents filed with or furnished to the SEC by Parent prior to the date hereof, or the corresponding sections or subsections of the disclosure letter delivered to the Company by Parent prior to entering into this Agreement (the "Parent Disclosure Letter") (it being agreed that disclosure of any item in any section or subsection of the Parent Disclosure Letter shall be deemed disclosure with respect to any other section or subsection to which the relevance of such item is reasonably apparent), Parent and Merger Sub each hereby represent and warrant to the Company that:

(a) Organization, Good Standing and Qualification. Each of Parent and Merger Sub is a legal entity duly organized, validly existing and in good standing under the Laws of its respective jurisdiction of organization and has all requisite corporate or similar power and authority to own, lease and operate its properties and assets and to carry on its business as presently conducted and is qualified to do business and is in good standing as a foreign corporation in each jurisdiction where the ownership, leasing or operation of its assets or properties or conduct of its business requires such qualification, except where the failure to be so organized, qualified or in such good standing, or to have such power or authority, would not, individually or in the aggregate, reasonably be expected to prevent, materially delay or impair the ability of Parent and Merger Sub to consummate the Merger and the other transactions contemplated by this Agreement. Parent has made available to the Company a complete and correct copy of the certificate of incorporation and bylaws or comparable governing documents of Parent and Merger Sub, each as in effect on the date of this Agreement.

(b) Corporate Authority. No vote of holders of capital stock of Parent is necessary to approve this Agreement and the Merger and the other transactions contemplated hereby. Each of Parent and Merger Sub has all requisite corporate power and authority and has taken all corporate action necessary in order to execute, deliver and perform its obligations under this Agreement, subject only to the adoption of this Agreement by Parent as the sole stockholder of Merger Sub, which will occur immediately following the execution of this Agreement, and to consummate the Merger. This Agreement has been duly executed and delivered by each of Parent and Merger Sub and is a valid and binding agreement of Parent and Merger Sub, enforceable against each of Parent and Merger Sub in accordance with its terms, subject to the Bankruptcy and Equity Exception.

(c) Governmental Filings and Approvals; No Violations; Etc.

(i) Other than the filings, approvals and/or notices (A) pursuant to Section 1.3, (B) under the HSR Act, (C) under the Exchange Act, (D) under stock exchange rules, (E) with the FERC under the Federal Power Act (the "Parent FERC Approval") and (F) the State Approvals (collectively, the "Parent Approvals"), no notices, reports or other filings are required to be made by Parent or Merger Sub with, nor are any consents, registrations, approvals, permits or authorizations required to be obtained by Parent or Merger Sub from, any Governmental Entity in connection with the execution, delivery and performance of this Agreement by Parent and Merger Sub and the consummation by Parent and Merger Sub of the Merger and the other transactions contemplated hereby, except those, the failure to make or obtain are not, individually or in the aggregate, reasonably likely to have a material adverse effect on Parent and its subsidiaries, taken as a whole, or prevent, materially delay or materially impair the ability of Parent and Merger Sub to consummate the Merger and the other transactions contemplated by this Agreement.

(ii) The execution, delivery and performance of this Agreement by Parent and Merger Sub do not, and the consummation by Parent and Merger Sub of the Merger and the other transactions contemplated hereby will not, constitute or result in (A) a breach or violation of, or a default under, the certificate of incorporation, certificate of formation or bylaws or comparable governing documents of Parent or Merger Sub or the comparable governing instruments of any of its Subsidiaries; (B) with or without notice, lapse of time or both, a breach or violation of, a termination (or right of termination) or a default under, the creation or acceleration of any obligations or the creation of a Lien on any of the assets of Parent or any of its Subsidiaries pursuant to, any Contracts binding upon Parent or any of its Subsidiaries or any Laws or governmental or non-governmental permit or license to which Parent or any of its Subsidiaries is subject; or (C) any change in the rights or obligations of any party under any of such Contracts, except, in the case of clause (B) or (C) above, for any breach, violation, termination, default, creation, acceleration or change that would not, individually or in the aggregate, reasonably be expected to prevent or materially delay the ability of Parent or Merger Sub to consummate the Merger and the other transactions contemplated by this Agreement.

(d) Litigation. There are no civil, criminal or administrative actions, suits, claims, hearings, investigations or proceedings pending or, to the Knowledge of Parent, threatened against Parent or Merger Sub by or before any Governmental Entity that seek to enjoin, or would reasonably be expected to have the effect of preventing, making illegal, or otherwise interfering with, any of the transactions contemplated by this Agreement, except as would not, individually or in the aggregate, reasonably be expected to prevent or materially delay the ability of Parent and Merger Sub to consummate the Merger and the other transactions contemplated by this Agreement.

The term "Knowledge" when used in this Agreement with respect to Parent shall mean the actual knowledge of the Chief Executive Officer, Chief Financial Officer and General Counsel.

(e) Available Funds. Parent and Merger Sub will have available to them on or before the Effective Time all funds necessary for the payment to the Paying Agent of the aggregate Per Share Merger Consideration and to satisfy all of their obligations under this Agreement, including amounts payable under Section 4.3. Parent currently has available to it all funds necessary for the payment to the Company of the aggregate consideration payable for the Nonvoting Preferred Stock to be issued, sold and delivered by the Company to Parent on the date hereof pursuant to the Subscription Agreement.

(f) Capitalization of Merger Sub. The authorized capital stock of Merger Sub consists solely of 1,000 shares of common stock, par value $0.01 per share, all of which are validly issued and outstanding. All of the issued and outstanding capital stock of Merger Sub is, and at the Effective Time will be, owned by Parent or a direct or indirect wholly-owned Subsidiary of Parent. Merger Sub has not conducted any business prior to the date hereof and has no, and prior to the Effective Time will have no, assets, liabilities or obligations of any nature other than those incident to its formation and pursuant to this Agreement and the Merger and the other transactions contemplated by this Agreement.

(g) Regulatory Matters. Each of Parent's Subsidiaries that engages in the sale of electricity at wholesale (other than any such Subsidiaries that own one or more facilities that constitute a "qualifying facility" as such term is defined under the Public Utility Regulatory Policies Act of 1978 and the rules and regulations of FERC that are entitled to exemption from regulation under Section 205 of the Federal Power Act) is regulated as a "public utility" under the Federal Power Act and has market-based rate authorization to make such sales at market-based rates. Each of Parent's Subsidiaries that directly owns generating facilities and operates their power generation facilities is in compliance with all applicable standards of NERC, other than non-compliance that would not reasonably be expected to prevent, materially delay or impair Parent from consummating the Merger and the other transactions contemplated by the Agreement or have, individually or in the aggregate, a material impact on Parent. There are no pending, or to the Knowledge of Parent, threatened, judicial or administrative proceedings (i) that would reasonably be expected to interfere with Parent's timely receipt of the Regulatory Approvals or (ii) that would revoke a Parent's Subsidiary's market-based rate authorization.

(h) Foreign Ownership, Control or Influence. Each officer and manager of Parent is a U.S. citizen, and to the Knowledge of Parent, none of the holders owning 5% or more of Parent's equity interests is, or is controlled by, a foreign Person or entity.

(i) Brokers. No agent, broker, finder or investment banker is entitled to any brokerage, finder's or other fee or commission in connection with the transactions contemplated by this Agreement based upon arrangements made by or on behalf of Parent or Merger Sub for which the Company could have any liability.

(j) Non-Reliance on Company Estimates, Projections, Forecasts, Forward-Looking Statements and Business Plans. In connection with the due diligence investigation of the Company by Parent and Merger Sub, Parent and Merger Sub have received and may continue to receive from the Company certain estimates, projections, forecasts and other forward-looking information, as well as certain business plan and cost-related plan information, regarding the Company, its Subsidiaries and their respective businesses and operations. Parent and Merger Sub hereby acknowledge that there are uncertainties inherent in attempting to make such estimates, projections, forecasts and other forward-looking statements, with which Parent and Merger Sub are familiar, that Parent and Merger Sub are taking full responsibility for making their own evaluation of the adequacy and accuracy of all estimates, projections, forecasts and other forward-looking information, as well as such business plans and cost-related plans, so furnished to them (including the reasonableness of the assumptions underlying such estimates, projections, forecasts, forward-looking information, business plans or cost-related plans), and that Parent and Merger Sub will have no claim against the Company or any of its Subsidiaries, or any of their respective stockholders, directors, officers, employees, Affiliates, advisors, agents or representatives, or any other Person, with respect thereto. Accordingly, Parent and Merger Sub hereby acknowledge that neither the Company nor any of its Subsidiaries, nor any of their respective stockholders, directors, officers, employees, Affiliates, advisors, agents or representatives, nor any other Person, has made or is making any representation or warranty with respect to such estimates, projections, forecasts, forward-looking statements, business plans or cost-related plans (including the reasonableness of the assumptions underlying such estimates, projections, forecasts, forward-looking statements, business plans or cost-related plans).

ARTICLE VI

Covenants

6.1. Interim Operations.

(a) The Company covenants and agrees as to itself and its Subsidiaries that, after the date hereof and prior to the Effective Time (unless Parent shall otherwise approve in writing (such approval not to be unreasonably withheld, delayed or conditioned)), and except as otherwise expressly permitted by this Agreement or as required by a Governmental Entity or applicable Laws, the business of it and its Subsidiaries shall be conducted in all material respects in the ordinary course and, to the extent consistent with the foregoing, the Company and its Subsidiaries shall use their respective commercially reasonable efforts to preserve their business organizations substantially intact, maintain satisfactory relationships with Governmental Entities, NERC, PJM, customers and suppliers having significant business dealings with them and keep available the services of their key employees; provided, however, that no action taken by the Company or its Subsidiaries with respect to matters specifically addressed by clauses (i)-(xx) of this Section 6.1(a) shall be deemed a breach of this sentence unless such action would constitute a breach of such other provision. In furtherance of the foregoing, from the date of this Agreement until the Effective Time, except (A) as otherwise expressly permitted by this Agreement, (B) as Parent may approve in writing (such approval not to be unreasonably withheld, delayed or conditioned), (C) as is required by applicable Law or any Governmental Entity or (D) as set forth in Section 6.1(a) of the Company Disclosure Letter, the Company will not and will not permit its Subsidiaries to:

(i) adopt any change in its certificate of incorporation or bylaws or other applicable governing instruments;

(ii) merge or consolidate the Company or any of its Subsidiaries with any other Person or restructure, reorganize or completely or partially liquidate the Company or any of its Subsidiaries, except for any such transactions among wholly-owned Subsidiaries of the Company;

(iii) acquire (including by merger, consolidation or acquisition of equity interests or assets or any other business combination) (A) any other Person or any organization or division of any other Person or (B) any assets outside of the ordinary course of business, other than acquisitions (1) pursuant to Contracts in effect as of the date of this Agreement (copies of which have been made available to Parent), (2) made in connection with any transaction solely between the Company and a wholly-owned Subsidiary of the Company or between wholly-owned Subsidiaries of the Company or (3) that would be permissible under clause (ix) below;

(iv) issue, sell, pledge, dispose of, grant, transfer, encumber, or authorize the issuance, sale, pledge, disposition, grant, transfer, lease, license, guarantee or encumbrance of, any shares of capital stock or other equity interests of the Company or any of its Subsidiaries (other than (A) the issuance of Shares upon the vesting, exercise or settlement of Company RSUs, Company PSUs, and Company Awards (and dividend equivalents thereon, if applicable) or (B) the issuance of shares by a wholly-owned Subsidiary of the Company to the Company or another wholly-owned Subsidiary), or securities convertible or exchangeable into or exercisable for any shares of such capital stock or other equity interests, or any options, warrants or other rights of any kind to acquire any shares of such capital stock or such convertible or exchangeable securities;

(v) make any loans, advances or capital contributions to or investments in any Person (other than among the Company and any direct or indirect wholly-owned Subsidiary of the Company or among the Company's wholly-owned subsidiaries) in excess of $10,000,000 in the aggregate other than loans, advances, capital contributions or investments made in the ordinary course of business;

(vi) declare, set aside, make or pay any dividend or other distribution, payable in cash, stock, property or otherwise, with respect to any of its capital stock (except for (A) regular quarterly dividends paid to holders of Shares in an amount and on a schedule consistent with the Company's past practices and not in excess of $0.27 per Share per quarter, (B) a "stub period" dividend to stockholders of record as of immediately prior to the Effective Time equal to the product of (x) the number of days from the record date for payment of the last quarterly dividend paid by the Company prior to the Effective Time through and including immediately prior to the Effective Time and (y) a daily dividend rate determined by dividing the amount of the last quarterly dividend prior to the Effective Time by ninety-one (91), and (C) dividends paid by any direct or indirect wholly-owned Subsidiary to the Company or to any other direct or indirect wholly-owned Subsidiary) or enter into any agreement with respect to the voting of its capital stock;

(vii) except for transactions among the Company and its wholly-owned Subsidiaries or among the Company's wholly-owned Subsidiaries, reclassify, split, combine, subdivide or redeem, purchase or otherwise acquire, directly or indirectly, any of its capital stock or securities convertible or exchangeable into or exercisable for any shares of its capital stock (other than the retention or acquisition of any Shares tendered by current or former employees or directors in order to pay Taxes in connection with the vesting, exercise or settlement of Company RSUs, Company PSUs, and Company Awards (and dividend equivalents thereon, if applicable));

(viii) incur, assume or otherwise become liable for any indebtedness for borrowed money or guarantee such indebtedness of another Person (other than of a wholly-owned Subsidiary of the Company), or issue or sell any debt securities or warrants or other rights to acquire any debt security of the Company or any of its Subsidiaries, other than (A) in the ordinary course of business (including to fund expenditures permissible under clauses (iii), (v) and (ix) of this Section 6.1(a)) or (B) other indebtedness in an aggregate principal amount not to exceed $50,000,000 outstanding at any time;

(ix) except for expenditures related to operational emergencies, equipment failures or outages make or authorize any capital expenditure in excess of $100,000,000 in the aggregate during any calendar year;

(x) make any material changes with respect to financial accounting policies or procedures, except as required by GAAP;

(xi) other than with respect to Rate Cases and the regulatory approval process, which are addressed in Section 6.5 and Transaction Litigation, which is addressed in Section 6.14, settle, release, waive or compromise any litigation claim, or other pending or threatened proceedings by or before a Governmental Entity if such settlement, release, waiver or compromise (A) with respect to the payment of monetary damages, involves the payment by the Company or any of its Subsidiaries of monetary damages that together with all other settlements, releases, waivers or compromises by the Company or any of its Subsidiaries exceed $50,000,000 individually or in the aggregate during any calendar year, net of any amount covered by insurance or third-party indemnification or (B) with respect to any non-monetary terms and conditions therein, imposes or requires actions that would or would be reasonably likely to have a material effect on the continuing operations of the Company or any of its Subsidiaries or Parent or any of its Subsidiaries after the Closing;

(xii) other than with respect to the Rate Cases, initiate, file or pursue any rate cases, or make any public announcement regarding an intent to file any rate cases;

(xiii) fail to make any regulatory filings required by Law, other than those regulatory filings that are otherwise addressed by this Agreement, except to the extent such failure would not have a material adverse effect on the continuing operations of the Company or any of its Subsidiaries or Parent or any of its Subsidiaries after the Closing;

(xiv) make, revoke or amend any material Tax election, enter into any closing agreement, settlement or compromise of any claim or assessment with respect to any material Tax liability (unless such closing agreement, settlement or compromise is not materially greater than the reserves established in accordance with GAAP in respect of the claim or assessment that is the subject of such closing agreement, settlement or compromise), amend any material Tax Return, surrender a claim for a material refund of Taxes or consent to any extension or waiver of the statute of limitations period applicable to any material Tax claim or assessment;

(xv) transfer, sell, lease, license, mortgage, pledge, surrender, encumber, divest, cancel, abandon or allow to lapse or expire or otherwise dispose of any material amount of assets, product lines or businesses of the Company or its Subsidiaries, including capital stock of any of its Subsidiaries, other than sales and dispositions of inventory, supplies and other assets (A) in the ordinary course of business or (B) pursuant to Contracts in effect prior to the date of this Agreement (copies of which have been made available to Parent);

(xvi) except as required pursuant to Contracts or Benefit Plans in effect prior to the date of this Agreement (including the Company Change in Control Severance Plan), (A) grant any equity awards, or grant or provide any material severance or material termination payments or benefits to any executive employee of the Company or its Subsidiaries who have individual employment agreements with severance or termination provisions or who participate in the Change of Control Severance Plan ("Executive Employees"), (B) accelerate or materially increase the compensation or employee benefits of any Executive Employee, except for annual merit-based or promotion-based pay increases in the ordinary course of business, (C) establish, adopt, terminate or materially amend any Benefit Plan (other than routine changes to welfare plans or any changes to Benefit Plans that would not result in more than a de minimis increase to the Company's costs under such Benefit Plans), including any severance benefit plan or (D) accelerate or materially increase the compensation of other employees of the Company or its Subsidiaries, except for (1) merit-based or promotion-based pay increases in the ordinary course of business, (2) acceleration or increases required by any CBA, or (3) any acceleration or increase done after consultation with Parent;

(xvii) enter into any Company Material Contract that contains a change of control or similar provision that would require a payment to any Person counterparty thereto in connection with the consummation of the Merger that would not otherwise be due;

(xviii) grant or incur any new Lien material to the Company and its Subsidiaries, other than (A) pledges or deposits by the Company or any of its Subsidiaries in the ordinary course of business under workmen's compensation Laws, unemployment insurance Laws or similar Laws; (B) good faith deposits in connection with Contracts (other than for the payment of indebtedness) to which the Company or one of its Subsidiaries is a party, or (C) in connection with securing indebtedness permitted to be incurred under the terms of this Agreement by granting or incurring Liens on the assets of the utility Subsidiaries of the Company, in each case, in the ordinary course of business; or

(xix) agree, authorize or commit to do any of the foregoing.

(b) Nothing contained in this Agreement is intended to give Parent, directly or indirectly, the right to control or direct the Company's or its Subsidiaries' operations prior to the Effective Time, and nothing contained in this Agreement is intended to give the Company, directly or indirectly, the right to control or direct Parent's or its Subsidiaries' operations. Prior to the Effective Time, each of Parent and the Company shall exercise, consistent with the terms and conditions of this Agreement, complete control and supervision over its and its Subsidiaries' respective operations.

6.2. Acquisition Proposals.

(a) No Solicitation or Negotiation. The Company agrees that except as expressly permitted by this Section 6.2, neither it nor any of its Subsidiaries, nor any of its or their respective directors, officers or employees, shall, and that it shall instruct and use its reasonable best efforts to cause its and its Subsidiaries' investment bankers, attorneys, accountants and other advisors and representatives not to (such investment bankers, attorneys, accountants and other advisors and representatives, collectively, "Representatives"), directly or indirectly:

(i) initiate, solicit or encourage any inquiries or the making of any proposal or offer that constitutes, or could reasonably be expected to lead to, any Acquisition Proposal;

(ii) engage in, continue or otherwise participate in any discussions or negotiations regarding, or provide any non-public information or data to any Person relating to, or that could reasonably be expected to lead to, any Acquisition Proposal;

(iii) facilitate knowingly any effort or attempt to make an Acquisition Proposal;

(iv) grant any waiver, amendment or release under any standstill agreement, or otherwise fail to enforce any standstill agreement (other than in each case, the right to waive or fail to enforce any prohibition on requests for amendments to any standstill agreement (or other similar "don't ask, don't waive" provisions) with any Person who, or any of whose Affiliates, did not submit an Acquisition Proposal between April 1, 2014 and the date of this Agreement); provided, however, that the Company shall not be prohibited from taking (or, in the case of enforcement, shall not be required to take) any such action if the board of directors of the Company shall have determined in good faith, after consultation with outside legal counsel, that failing to take such action (or in the case of enforcement, taking such action) would be reasonably likely to be inconsistent with the directors' fiduciary duties under applicable Law;

(v) execute or enter into any letter of intent, agreement in principle, term sheet, memorandum of understanding, merger agreement, acquisition agreement or other similar agreement relating to an Acquisition Proposal (other than an Acceptable Confidentiality Agreement) (an "Alternative Acquisition Agreement"); or

(vi) resolve or agree to do any of the foregoing.

(b) Notwithstanding anything in the foregoing to the contrary, prior to the time, but not after, the Company Requisite Vote is obtained, the Company may (A) provide information in response to a request therefor by a Person who has made an unsolicited *bona fide* written Acquisition Proposal if prior to providing such information the Company receives from the Person so requesting such information an executed confidentiality agreement on terms that are not less restrictive to the other party than those contained in the Confidentiality Agreement, it being understood that such confidentiality agreement need not prohibit the making, or amendment, of an Acquisition Proposal (an "Acceptable Confidentiality Agreement"); and promptly discloses (and, if applicable, provides copies of) any such information to Parent to the extent not previously disclosed or provided; (B) engage or participate in any discussions or negotiations with any Person who has made such an unsolicited *bona fide* written Acquisition Proposal; or (C) after having complied with Section 6.2(d), make a Change of Recommendation or approve, recommend, or otherwise declare advisable or propose to approve, recommend or declare advisable (publicly or otherwise) with respect to such Acquisition Proposal; if and only to the extent that, (x) prior to taking any action described in clause (A), (B) or (C) above, the board of directors of the Company shall have determined in good faith, after consultation with its outside legal counsel, that failure to take such action would be reasonably likely to be inconsistent with the directors' fiduciary duties under applicable Law, (y) in each case referred to in clause (A) and (B), the board of directors of the Company shall have determined in good faith, after consultation with its financial advisors and outside legal counsel, that such Acquisition Proposal either constitutes a Superior Proposal or is reasonably likely to result in a Superior Proposal, and (z) in the case referred to in clause (C) above, the board of directors of the Company determines in good faith (after consultation with its financial advisor and outside legal counsel) that such Acquisition Proposal is a Superior Proposal.

(c) Definitions. For purposes of this Agreement:

"Acquisition Proposal" means (i) any proposal or offer with respect to a merger, joint venture, partnership, consolidation, dissolution, liquidation, tender offer, recapitalization, reorganization, share exchange, business combination or similar transaction involving the Company and/or any of its Significant Subsidiaries or (ii) any direct or indirect acquisition by any Person or "group" (as defined in the Exchange Act) resulting in, or proposal or offer, which if consummated would result in, any Person or "group" (as defined in the Exchange Act) becoming the beneficial owner, directly or indirectly, in one or a series of related transactions, of 15% or more of the total voting power or of any class of equity securities of the Company, or assets representing 15% or more of the net revenues, net income or consolidated total assets (measured by fair market value) of the Company and its Subsidiaries, taken as a whole (including equity securities of its Subsidiaries), in each case other than the Merger.

"Superior Proposal" means a *bona fide* Acquisition Proposal (for purposes of this definition, replacing all references in the definition of "Acquisition Proposal" to 15% with 75%), that the board of directors of the Company has determined in its good faith judgment is reasonably likely to be consummated in accordance with its terms, after consultation with its financial advisors and outside legal counsel, taking into account all legal, financial, and regulatory aspects of the Acquisition Proposal, and the Person making the Acquisition Proposal, and, if consummated would result in a transaction more favorable to the Company's stockholders from a financial point of view than the transaction contemplated by this Agreement (after taking into account any proposed revisions to the terms of the transactions contemplated by Section 6.2(d) of this Agreement).

(d) No Change in Recommendation or Alternative Acquisition Agreement. The board of directors of the Company and each committee of the board of directors shall not:

(i) (A) withhold, withdraw, qualify or modify (or publicly propose or resolve to withhold, withdraw, qualify or modify), in a manner adverse to Parent, the Company Recommendation (B) fail to include the Company Recommendation in the Proxy Statement, (C) approve, recommend or otherwise declare advisable or propose or resolve to approve, recommend or otherwise declare advisable (publicly or otherwise), any Acquisition Proposal, or (D) fail to publicly reaffirm the Company Recommendation within ten business days after Parent so requests in writing (provided, that Parent shall be entitled to make such a written request for reaffirmation only once for each Acquisition Proposal and once for each material amendment to such Acquisition Proposal) (any action described in clauses (A) and (D) a "Change of Recommendation"); or

(ii) Except as expressly permitted by, and after compliance with this Section 6.2(d), cause or permit the Company to enter into any Alternative Acquisition Agreement.

Notwithstanding anything to the contrary set forth in this Agreement, prior to the time, but not after, the Company Requisite Vote is obtained, the board of directors of the Company (x) may make a Change of Recommendation and in connection therewith, approve, recommend or otherwise declare advisable, and enter into an Alternative Acquisition Agreement in connection with a Superior Proposal made after the date of this Agreement (if such Superior Proposal did not result from a material breach of Section 6.2(a) and such Superior Proposal is not withdrawn) or (y) may make a Change of Recommendation as a result of the occurrence of an Intervening Event, if, the board of directors of the Company determines in good faith, after consultation with its outside legal counsel, that failure to do so would be reasonably likely to be inconsistent with the directors' fiduciary duties under applicable Law; provided, however, that the board of directors of the Company shall not (i) in the case of clause (x) make a Change of Recommendation with respect to a Superior Proposal and authorize the Company to enter into any Alterative Acquisition Agreement or (ii) in the case of clause (y) make a Change of Recommendation unless:

(i) the Company has notified Parent in writing that it intends to effect a Change of Recommendation, describing in reasonable detail the reasons for such Change of Recommendation (a "Recommendation Change Notice") (it being agreed that the Recommendation Change Notice and any amendment or update to such notice and the determination to so deliver such notice, or update or amend public disclosures with respect thereto shall not constitute a Change of Recommendation for purposes of this Agreement), and if such proposed Change of Recommendation relates to an Acquisition Proposal, has provided copies of the most current version of all documents relating to such Acquisition Proposal, and if such proposed Change of Recommendation relates to an Intervening Event, such Recommendation Change Notice specifies the facts and circumstances of such Intervening Event; and

(ii) (x) if requested by Parent, the Company shall have made its Representatives available to discuss and negotiate in good faith with Parent and its Representatives any proposed modifications to the terms and conditions of this Agreement during the three business days following the date on which the Recommendation Change Notice is delivered to Parent and (y) if Parent shall have delivered to the Company a written, binding and irrevocable offer to alter the terms or conditions of this Agreement during such three business day period, the board of directors of the Company shall have determined in good faith after consultation with its financial advisors and outside legal counsel, after considering the terms of such offer by Parent, that the failure to effect a Change of Recommendation would be reasonably likely to be inconsistent with its fiduciary duties under applicable Law, and that in the case of a Change of Recommendation with respect to an Acquisition Proposal, such Acquisition Proposal would continue to constitute a Superior Proposal if the changes offered by Parent were given effect, and that in the case of an Intervening Event, the board of directors of the Company still intends to effect a Change of Recommendation if the changes offered by Parent were given effect; provided that in the event the Acquisition Proposal is thereafter modified by the party making such Acquisition Proposal, the Company shall notify Parent in writing of such modified Acquisition Proposal and shall again comply with the requirements of this clause (ii).

"Intervening Event" shall mean any change, event or occurrence that is (a) unknown to or by the board of directors of the Company as of the date of this Agreement (or if known, the magnitude or material consequences of which were not known or understood by the board of directors of the Company as of the date of this Agreement) and (b) becomes known to or by the board of directors of the Company prior to obtaining the Company Requisite Vote.

(e) Certain Permitted Disclosure. Nothing contained in this Section 6.2 shall be deemed to prohibit the Company or the board of directors of the Company from (i) complying with its disclosure obligations under U.S. federal or state Law with regard to an Acquisition Proposal, including taking and disclosing to its stockholders a position contemplated by Rule 14d-9 or Rule 14e-2(a) under the Exchange Act (or any similar communication to stockholders); or (ii) making any "stop, look and listen" communication to the stockholders of the Company pursuant to Rule 14d-9(f) under the Exchange Act.

(f) Existing Discussions. The Company agrees that it and its Subsidiaries will, and that it will instruct and use its reasonable best efforts to cause its and its Subsidiaries' Representatives to immediately cease and cause to be terminated any existing activities, discussions or negotiations with any parties conducted heretofore with respect to any Acquisition Proposal. The Company agrees that it will take the necessary steps to promptly inform the individuals or entities referred to in the first sentence hereof of the obligations undertaken in this Section 6.2.

(g) Notice. The Company agrees that it will promptly (and, in any event, within 24 hours) notify Parent if any proposals or offers with respect to an Acquisition Proposal are received by, any non-public information is requested from, or any discussions or negotiations are sought to be initiated or continued with, the Company or any of its Representatives indicating, in connection with such notice, the identity of the Person or group of Persons making the proposal, offer or request and the material terms and conditions of any proposals or offers (including, if applicable, copies of any written requests, proposals or offers, including proposed agreements) and thereafter shall keep Parent reasonably informed, on a prompt basis (and, in any event, within 24 hours), of the status and terms of any such proposals or offers (including any material amendments thereto or any change to the scope or material terms or conditions thereof, and including copies of additional written materials or material modifications thereof) and the status of any such discussions or negotiations, including any change in the Company's intentions as previously notified.

6.3. Proxy Statement.

(a) The Company shall, as promptly as practicable after the date of this Agreement (and in any event within 30 business days following the date of this Agreement), prepare and file a proxy statement in preliminary form relating to the Stockholders Meeting (such proxy statement, including any amendment or supplement thereto, the "Proxy Statement") with the SEC. The Company agrees that as of the date of mailing to stockholders of the Company and at the time of the Stockholders Meeting, (i) the Proxy Statement will comply in all material respects with the applicable provisions of the Exchange Act and the rules and regulations thereunder and (ii) none of the information supplied by it or any of its Subsidiaries for inclusion or incorporation by reference in the Proxy Statement will contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading. Parent and Merger Sub agree that none of the information supplied by either of them or any of their Affiliates for inclusion in the Proxy Statement will contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading.

(b) The Company shall promptly notify Parent of the receipt of all comments from the SEC with respect to the Proxy Statement and of any request by the SEC for any amendment or supplement thereto or for additional information and shall promptly provide to Parent copies of all correspondence between the Company and/or any of its Representatives and the SEC with respect to the Proxy Statement. The Company and Parent shall each use its reasonable best efforts to promptly provide responses to the SEC with respect to all comments received on the Proxy Statement from the SEC. The Company shall cause the definitive Proxy Statement to be mailed promptly after the date the SEC staff advises that it has no further comments thereon or that the Company may commence mailing the Proxy Statement.

6.4. Stockholders Meeting. Subject to fiduciary obligations under applicable Law, the Company will take, in accordance with applicable Law and its certificate of incorporation and bylaws, all reasonable action necessary to convene a meeting of holders of Shares (the "Stockholders Meeting") as promptly as practicable (but in any event within 60 days) after the date on which the SEC staff advises that it has no further comments thereon or that the Company may commence mailing the Proxy Statement to consider and vote upon the adoption of this Agreement; provided, that the Company shall not postpone, recess or adjourn such meeting except (a) to the extent required by Law, (b) to allow reasonable additional time for the filing and/or mailing of any supplemental or amended disclosure that the board of directors of the Company has determined in good faith after consultation with outside legal counsel is necessary under applicable Law and for such supplemental or amended disclosure to be disseminated and reviewed by the Company's stockholders prior to the Stockholders Meeting, or (c) one adjournment for a period of up to 10 days only to solicit additional proxies so as to establish a quorum or to obtain the Company Requisite Vote, with the consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed). Subject to Section 6.2, the board of directors of the Company and any committee thereof shall recommend such adoption and, unless and until there has been a Change of Recommendation, shall include the Company Recommendation in the Proxy Statement and take all reasonable lawful action to solicit such adoption of this Agreement. Notwithstanding any Change of Recommendation, unless this Agreement is terminated pursuant to Article VIII, this Agreement shall be submitted to the holders of Shares at the Stockholders Meeting for the purpose of adopting this Agreement.

6.5. Filings; Other Actions; Notification.

(a) Cooperation. Subject to the terms and conditions set forth in this Agreement, including Section 6.5(e) below, the Company and Parent shall cooperate with each other and use (and shall cause their respective Subsidiaries to use) their respective reasonable best efforts to take or cause to be taken all actions, and do or cause to be done all things, reasonably necessary, proper or advisable on its part under this Agreement and applicable Laws to consummate and make effective the Merger as soon as practicable, including preparing and filing as promptly as practicable (and in any event shall make all filings with the State Commissions, the FERC, the FCC and pursuant to the HSR Act within 60 days of the date hereof) all documentation to effect all necessary notices, reports and other filings and to obtain as promptly as practicable all consents, registrations, approvals, permits and authorizations necessary or advisable to be obtained from any third party and/or any Governmental Entity in order to consummate the Merger. The Company and Parent will each request early termination of the waiting period with respect to the Merger under the HSR Act. Subject to applicable Laws relating to the exchange of information, Parent and the Company shall have the right to review in advance and, to the extent practicable, each will consult with the other on and consider in good faith the views of the other in connection with, all of the information relating to Parent or the Company, as the case may be, and any of their respective Subsidiaries, that appears in any filing made with, or written materials submitted to, any third party and/or any Governmental Entity in connection with the Merger (including the Proxy Statement). In exercising the foregoing rights, each of the Company and Parent shall act reasonably and as promptly as practicable. Nothing in this Agreement shall require the Company or its Subsidiaries to take or agree to take any action with respect to its business or operations unless the effectiveness of such agreement or action is conditioned upon Closing.

(b) Information. Subject to applicable Laws, the Company and Parent each shall, upon request by the other, furnish the other with all information concerning itself, its Subsidiaries, directors, officers and stockholders and such other matters as may be reasonably necessary or advisable in connection with the Proxy Statement or any other statement, filing, notice or application made by or on behalf of Parent, the Company or any of their respective Subsidiaries to any third party and/or any Governmental Entity in connection with the Merger and the transactions contemplated by this Agreement, including under the HSR Act and any other applicable antitrust Law; provided, however, that either party may designate information "for outside counsel only" and either party may redact information related to the value of the transaction. Subject to applicable Laws relating to the exchange of information and except as otherwise provided in this Agreement, Parent and the Company shall have the right to review in advance, and to the extent practicable each will consult with the other regarding, and consider in good faith the views of the other in connection with, all of the information relating to Parent or the Company, as the case may be, and any of their respective Affiliates and Representatives, that appears in any filing made with, or written materials submitted to, any Governmental Entity in connection with the Merger and the other transactions contemplated by this Agreement. In exercising the foregoing rights, each of the Company and Parent shall act reasonably and as promptly as practicable.

(c) Status. Subject to applicable Laws and the instructions of any Governmental Entity, the Company and Parent each shall keep the other apprised of the status of matters relating to completion of the transactions contemplated hereby, including promptly furnishing the other with copies of notices or other communications received by Parent or the Company, as the case may be, or any of their respective Representatives, from any third party and/or any Governmental Entity with respect to the Merger; provided, however, that either party may designate information or notices or other communications as "for outside counsel only". Neither the Company nor Parent shall permit any of its officers or any other Representatives to participate in any meeting or substantive telephone discussion with any Governmental Entity in respect of any filings, investigation or other inquiry with respect to the Merger unless to the extent practicable (i) it consults with the other party in advance and (ii) and to the extent permitted by such Governmental Entity, gives the other party the opportunity to attend and participate in such meeting or substantive telephone discussion.

(d) Regulatory Matters. Subject to the terms and conditions set forth in this Agreement, without limiting the generality of the other undertakings pursuant to this Section 6.5, each of the Company (in the case of Sections 6.5(d)(i) and 6.5(d)(iii) set forth below) and Parent (in all cases set forth below) agree to take or cause to be taken the following actions:

(i) the prompt provision to each and every federal, state, local or foreign court or Governmental Entity (including the FERC, the FCC and the State Commissions) with jurisdiction over any Company Approvals or Parent Approvals of non-privileged information and documents requested by any such Governmental Entity that are necessary, proper or advisable to permit consummation of the Merger;

(ii) the prompt use of its reasonable best efforts to avoid the entry or enactment of any permanent, preliminary or temporary injunction or other order, decree, decision, determination, judgment or Law that would delay, restrain, prevent, enjoin or otherwise prohibit consummation of the Merger; and

(iii) the prompt use of its reasonable best efforts to take, in the event that any permanent, preliminary or temporary injunction, decision, order, judgment, determination, decree or Law is entered, issued or enacted, or becomes reasonably foreseeable to be entered, issued or enacted, in any proceeding, review or inquiry of any kind that would make consummation of the Merger in accordance with the terms of this Agreement unlawful or that would delay, restrain, prevent, enjoin or otherwise prohibit consummation of the Merger, any and all steps (including the appeal thereof, the posting of a bond or the taking of the steps contemplated by clause (ii) of this Section 6.5(d)) necessary to resist, vacate, modify, reverse, suspend, prevent, eliminate, avoid or remove such actual, anticipated or threatened injunction, decision, order, judgment, determination, decree or enactment so as to permit such consummation on a schedule as close as possible to that contemplated by this Agreement;

provided that nothing herein shall require (and reasonable best efforts shall in no event require) any party or its Subsidiaries to agree to or take any action that would otherwise constitute a Burdensome Condition. A "Burdensome Condition" shall mean any terms, conditions, liabilities, obligations, commitments or sanctions imposed upon Parent, the Company or their respective Subsidiaries (A) in the Regulatory Approvals, or (B) in any Laws enacted for the purpose of imposing terms, conditions, liabilities, obligations, commitments or sanctions in connection with the Merger (any of the foregoing in clause (B) a "Merger Law"), that, individually or in the aggregate, would constitute or be reasonably likely to constitute a Regulatory Failure (as defined below), provided, however, that any such terms, conditions, liabilities, obligations, commitments or sanctions shall not be taken into account in determining whether there has been or is such a Regulatory Failure to the extent they implement the Regulatory Commitments. A "Regulatory Failure" shall mean terms, conditions, liabilities, obligations, commitments or sanctions (giving effect to the value of any negative effects net of their benefits) that in an aggregate amount constitute a material and adverse effect on the condition (financial or otherwise), assets, liabilities, businesses or results of operations of the Company and its Subsidiaries, taken as a whole, provided, that, for the purposes of determining the existence of a Regulatory Failure, (i) the Company and its Subsidiaries shall be deemed to have 50% of the assets, liabilities, businesses and results of operations of the Company and its Subsidiaries, taken as a whole, and (ii) any terms, conditions, liabilities, obligations, commitments or sanctions imposed upon Parent and its Subsidiaries shall be deemed to have been imposed on the Company and its Subsidiaries.

(e) Regulatory Commitments. The Company and Parent agree (i) that the applications submitted to FERC and the State Commissions with respect to the Merger shall include the information concerning the Merger, the Company and its Subsidiaries, and Parent required by applicable Laws of the District of Columbia, the States of Delaware, Maryland, and New Jersey, the Commonwealth of Virginia and such other jurisdictions as may be mutually determined by the Company and Parent, as the case may be, (ii) that such applications and any amendments or supplements thereto shall include the Regulatory Commitments to the extent applicable to such jurisdictions and such additional agreements or commitments as the Company and Parent agree are advisable to obtain prompt approval of such applications, and (iii) that neither the Company nor Parent shall agree to, or accept, any additional or different agreements, commitments or conditions in connection with the Merger pursuant to any settlement or otherwise with any State Commissions or any other Person, in the case of any agreement, commitment or condition to which the Company of any of its Subsidiaries is a party or otherwise affecting the Company or any of its Subsidiaries, without the prior written consent of Parent, and in the case of any agreement, commitment or condition to which Parent is a party and affecting the Company or any of its Subsidiaries, without the prior written consent of the Company if such agreement, commitment or condition is effective prior to the Effective Time. Parent further agrees that, subject to obtaining the consent of the Company as required by this Section 6.5(e), it will agree to, or accept, any additional or different agreements, commitments or conditions that do not, individually or in the aggregate, constitute a Burdensome Condition to obtain any governmental approvals necessary to promptly consummate the Merger, including any Parent Approval or the FERC Approval, the State Approvals and the FCC Approval.

(f) Rate Cases. Between the date of this Agreement and the Closing, the Company and its Subsidiaries shall be permitted to continue to diligently pursue the rate cases set forth on Section 6.5(f) of the Company Disclosure Letter (collectively, the "Rate Cases") consistent with past practice, and to the extent permitted by Law, notify Parent about any material developments, or material communications with the FERC or the applicable State Commission, relating thereto. Except as required by Exhibit B, prior to making any commitments or settlement offers in the Rate Cases, the Company shall (and shall cause its Subsidiaries to) consult with Parent and consider in good faith any suggestions made by Parent in connection therewith. The Company shall not (and shall cause its Subsidiaries not to) settle the Rate Cases without the prior written consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed) to the extent that such settlement would result in an outcome for the Company and its Subsidiaries that would be materially adverse to the Company or any of its Subsidiaries, taking into account the requests made by the Company and its Subsidiaries in the proceeding, the resolution of similar recent proceedings by the Company and its Subsidiaries and the reasonable expectations of Parent as of the date hereof for such outcome.

6.6. Access and Reports.

(a) Subject to applicable Law, upon reasonable notice, the Company shall (and shall cause its Subsidiaries to) afford Parent's officers and other authorized Representatives (including financing sources) reasonable access, during normal business hours throughout the period prior to the Effective Time, to its employees, properties, books, contracts and records and, during such period, the Company shall (and shall cause its Subsidiaries to) furnish promptly to Parent all information concerning its business, properties and personnel as may reasonably be requested, provided that no investigation pursuant to this Section 6.6 shall affect or be deemed to modify any representation or warranty made by the Company herein, and provided, further, that the foregoing shall not require the Company (i) to permit any inspection, or to disclose any information, that in the reasonable judgment of the Company would result in the disclosure of any trade secrets of third parties or violate any obligations of the Company or any of its Subsidiaries with respect to confidentiality if the Company shall have used reasonable best efforts to obtain the consent of such third party to such inspection or disclosure or (ii) to disclose any privileged information of the Company or any of its Subsidiaries. All requests for information made pursuant to this Section 6.6 shall be directed to the executive officer or other Person designated by the Company. All such information shall be governed by the terms of the Confidentiality Agreement.

(b) Financing Cooperation. The Company shall, and shall cause its Subsidiaries to, use its and their reasonable best efforts to provide such cooperation as may be reasonably requested by Parent in connection with the financing of the Transactions, including using reasonable best efforts to (i) provide reasonable assistance with the preparation of any discussions of business, financial statements, pro forma financials, projections, management discussion and analysis, and other customary financial data of the Company and its Subsidiaries, all for use in connection therewith and (ii) direct its independent accountants to provide customary and reasonable assistance to Parent including in connection with providing customary comfort letters. Parent shall reimburse the Company for all reasonable out-of-pocket costs or expenses incurred by the Company and its Subsidiaries in connection with cooperation provided for in this Section 6.6(b) to the extent the information requested of the Company was not otherwise prepared or available in the ordinary course of business. For the avoidance of doubt, Parent hereby expressly acknowledges that its obligations under this Agreement are not subject to the availability of any financing.

6.7. Stock Exchange De-listing. Prior to the Closing Date, the Company shall cooperate with Parent and use reasonable best efforts to take, or cause to be taken, all actions, and do or cause to be done all things, reasonably necessary, proper or advisable on its part under applicable Laws and rules and policies of the NYSE to enable the delisting by the Surviving Corporation of the Shares from the NYSE and the deregistration of the Shares under the Exchange Act as promptly as practicable after the Effective Time.

6.8. Publicity. The initial press release regarding the Merger shall be a joint press release and thereafter the Company and Parent each shall consult with each other prior to issuing any press releases or otherwise making public announcements with respect to the Merger and the other transactions contemplated by this Agreement and prior to making any filings with any third party and/or any Governmental Entity (including any national securities exchange or interdealer quotation service) with respect thereto, and no public release or announcement concerning the Merger or any other transactions contemplated by this Agreement shall be issued or made by any party without the prior consent of the other parties except as may be required by Law or by obligations pursuant to any listing agreement with or rules of any national securities exchange or interdealer quotation service or by the request of any Governmental Entity (in which case the party required to issue or make such press release or announcement shall give reasonable notice to the other party or parties, including the opportunity to review or comment on such press release or announcement to the extent practicable).

6.9. Employee Benefits.

(a) Parent agrees that, during the period commencing at the Effective Time and ending two years after the Effective Time ("Benefit Period"), Parent shall provide, or shall cause to be provided (1) to each employee of the Company and its Subsidiaries (other than any employee who is covered by a collective bargaining or similar agreement between the Company and any labor union) who is employed as of immediately prior to the Effective Time and continues employment with the Company or its Subsidiaries immediately after the Effective Time (each, a "Continuing Employee"), base salary, annual incentive opportunity and long-term incentive compensation opportunities, which are, in each case, no less than those provided by the Company and its Subsidiaries immediately prior to the Effective Time to each such Continuing Employee, (2) to the Continuing Employees, pension and welfare benefits and perquisites (to the extent described in the Company Disclosure Letter) that are no less favorable in the aggregate than those provided by the Company and its Subsidiaries immediately prior to the Effective Time and (3) to the Continuing Employees, severance benefits that are no less favorable than the severance benefits provided by the Company and its Subsidiaries to such Continuing Employees immediately prior to the Effective Time.

(b) For purposes of vesting, benefit accrual (but not for benefit accrual purposes under any defined benefit pension plan), vacation and sick time credit and eligibility to participate under the employee benefit plans, programs and policies of Parent and its Subsidiaries providing benefits to any Continuing Employee after the Effective Time (including the Benefit Plans) (the "New Plans"), each Continuing Employee shall be credited with his or her years of service with the Company and its Subsidiaries and their respective predecessors before the Effective Time, to the same extent and for the same purpose as such Continuing Employee was entitled, before the Effective Time, to credit for such service under any similar Benefit Plan in which such Continuing Employee participated or was eligible to participate immediately prior to the Effective Time; provided that the foregoing shall not apply to the extent that its application would result in a duplication of benefits with respect to the same period of service. In addition, and without limiting the generality of the foregoing, Parent shall cause (i) each Continuing Employee to be immediately eligible to participate, without any waiting time, in any and all New Plans to the extent coverage under such New Plan is replacing comparable coverage under a Benefit Plan in which such Continuing Employee participated immediately before the Effective Time (such plans, collectively, the "Old Plans"), and (ii) for purposes of each New Plan providing medical, dental, pharmaceutical and/or vision benefits to any Continuing Employee, any evidence of insurability requirements, all pre-existing condition exclusions and actively-at-work requirements of such New Plan to be waived for such Continuing Employee and his or her covered dependents, to the extent such conditions were inapplicable or waived under the comparable Old Plan. Parent shall cause any eligible expenses incurred by any Continuing Employee and his or her covered dependents during the portion of the plan year of the Old Plan ending on the date such Continuing Employee's participation in the corresponding New Plan begins to be taken into account under such New Plan for purposes of satisfying all deductible, coinsurance and maximum out-of-pocket requirements applicable to such Continuing Employee and his or her covered dependents for the applicable plan year; provided that such amount was taken into account for the same purpose under the similar Benefit Plan for such period and would not result in the duplication of benefits.

(c) Parent hereby acknowledges that a "change in control" or other event with similar import, within the meaning of the Benefit Plans that contain such terms will occur upon the Effective Time. Parent shall, and shall cause the Surviving Corporation and any successor thereto to, honor, assume, fulfill and discharge the Company's and its Subsidiaries' obligations under the Company's Change in Control Severance Plan and the other Benefit Plans listed on Section 6.9(c) of the Company Disclosure Letter. Parent agrees that it will not (nor cause any other Person or entity to) request that the Company or any Continuing Employee waive or relinquish any compensation or benefit entitlement or right (including any severance entitlement) existing as of the Effective Time.

(d) (i) If the Effective Time occurs during calendar year 2014, at the Effective Time the Company shall pay each participant in the Company's incentive plans (the "Incentive Plans") who remains employed through the Effective Time, an annual incentive amount in respect of the 2014 fiscal year, equal to the higher of (A) the target level (at 100% funding) and (B) the actual level of performance achieved as of the Effective Time (with such performance measure pro-rated, if applicable, for the portion of the performance cycle completed at the Effective Time), as determined by the compensation committee of the board of directors of the Company prior to the Effective Time in accordance with the terms of the applicable Incentive Plans and based on performance through the day that is no more than five business days prior to the Effective Time.

(ii) If the Effective Time has not occurred by December 31, 2014 (or December 31, 2015), the Company shall (A) determine the amounts earned under the Incentive Plans in respect of the 2014 fiscal year (or 2015 fiscal year), with performance based on either (x) the target level (at 100% funding) or (y) the actual level of performance for the 2014 fiscal year (or 2015 fiscal year), (B) pay such amounts in respect of the 2014 fiscal year (or 2015 fiscal year) no later than the Closing Date and (C) establish annual incentive award targets, maximums and performance award levels and performance measures for the 2015 fiscal year (or 2016 fiscal year) under the Incentive Plans.

(iii) If the Effective Time occurs during calendar year 2015, the Company shall pay such amounts in respect of the 2015 fiscal year on the Closing Date, with performance determined at the higher of (x) target level (at 100% funding) and (y) the actual level of performance for the 2015 fiscal year achieved as of the Effective Time (with such performance measure pro-rated, if applicable, for the portion of the performance cycle completed at the Effective Time), as determined by the compensation committee of the board of directors of the Company prior to the Effective Time based on performance through the day that is no more than five business days prior to the Effective Time.

(iv) If the Effective Time occurs during calendar year 2016, the Company shall pay such amounts in respect of the 2016 fiscal year on the Closing Date, pro-rated based on the number of calendar days elapsed in the 2016 fiscal year through the Closing Date, with performance determined at the higher of (x) target level (at 100% funding) and (y) the actual level of performance for the 2016 fiscal year achieved as of the Effective Time (with such performance measure pro-rated, if applicable, for the portion of the performance cycle completed at the Effective Time), as determined by the compensation committee of the board of directors of the Company prior to the Effective Time based on performance through the day that is no more than five business days prior to the Effective Time, and Parent shall, and shall cause the Surviving Corporation to, honor and pay incentive award amounts for the remainder of the 2016 fiscal year (with an offset for the pro rata portion previously paid) in accordance with the targets, levels and measures established by the Company prior to the Closing Date and the terms of the applicable Incentive Plans.

(e) After the Effective Time, except as required by Section 304 of the Sarbanes-Oxley Act of 2002, the Company shall have no further rights to seek recovery from employees of amounts paid under the Stock Plans or the Incentive Plans for periods ending on or prior to the Effective Time.

(f) No later than the Effective Time, the Company shall take all actions reasonably necessary to cause each Continuing Employee to become 100% vested in such Continuing Employee's accounts under each Company 401(k) plan (excluding for the avoidance of doubt any 401(k) plans maintained pursuant to any collective bargaining or similar agreement between the Company and any labor union), effective as of the Closing Date.

(g) With respect to each individual who is employed by the Company or any of its Subsidiaries immediately before the Effective Time whose terms and conditions of employment are governed by a CBA between the Company and any labor union, Parent shall, or shall cause the Surviving Corporation to, continue to honor such CBA, through its expiration, modification or termination in accordance with its terms or applicable Law.

(h) The provisions of this Section 6.9 are solely for the benefit of the parties to this Agreement, and nothing in this Agreement, whether express or implied, is intended to, or shall, (i) constitute the establishment or adoption of or an amendment to any employee benefit plan for purposes of ERISA or otherwise be treated as an amendment or modification of any Benefit Plan, New Plan or other benefit plan, agreement or arrangement, other than Section 6.9(f), (ii) limit the right of Parent, the Company or their respective Subsidiaries to amend, terminate or otherwise modify any Benefit Plan, New Plan or other benefit plan, agreement or arrangement following the Effective Time, or (iii) create any third-party beneficiary or other right (including, but not limited to, a right to employment) in any Person, including any current or former employee of the Company or any Subsidiary of the Company, any participant in any Benefit Plan, New Plan or other benefit plan, agreement or arrangement (or any dependent or beneficiary thereof).

6.10. Expenses. The Surviving Corporation shall pay all charges and expenses, including those of the Paying Agent, in connection with the transactions contemplated in Article IV, and Parent shall reimburse the Surviving Corporation for such charges and expenses. Except as otherwise provided in Section 8.5, whether or not the Merger is consummated, all costs and expenses incurred in connection with this Agreement and the Merger and the other transactions contemplated by this Agreement shall be paid by the party incurring such expense.

6.11. Indemnification; Directors' and Officers' Insurance. (a) From and after the Effective Time, each of Parent and the Surviving Corporation agrees that it will indemnify and hold harmless, to the fullest extent permitted under applicable Law (and Parent shall also advance expenses as incurred to the fullest extent permitted under applicable Law, provided that the Person to whom expenses are advanced provides an undertaking to repay such advances if it is ultimately determined that such Person is not entitled to indemnification), each present and former director and officer of the Company and its Subsidiaries (collectively, the "Indemnified Parties") against any costs or expenses (including reasonable attorneys' fees), judgments, fines, losses, claims, damages or liabilities incurred in connection with any claim, action, suit, proceeding or investigation, whether civil, criminal, administrative or investigative, arising out of or related to such Indemnified Parties' service as a director or officer of the Company or its Subsidiaries or services performed by such persons at the request of the Company or its Subsidiaries at or prior to the Effective Time, whether asserted or claimed prior to, at or after the Effective Time, including the transactions contemplated by this Agreement.

(b) Prior to the Effective Time, the Company shall and, if the Company is unable to, Parent shall cause the Surviving Corporation as of the Effective Time to, obtain and fully pay the premium for the extension of (i) the directors' and officers' liability coverage of the Company's existing directors' and officers' insurance policies, and (ii) the Company's existing fiduciary liability insurance policies, in each case for a claims reporting or discovery period of six years from and after the Effective Time from an insurance carrier with the same or better credit rating as the Company's current insurance carrier with respect to directors' and officers' liability insurance and fiduciary liability insurance (collectively, "D&O Insurance") with terms, conditions, retentions and limits of liability that are at least as favorable as the Company's existing policies with respect to any actual or alleged error, misstatement, misleading statement, act, omission, neglect, breach of duty or any matter claimed against a director or officer of the Company or any of its Subsidiaries by reason of him or her serving in such capacity that existed or occurred at or prior to the Effective Time (including in connection with this Agreement or the transactions or actions contemplated hereby). If the Company and the Surviving Corporation for any reason fail to obtain such "tail" insurance policies as of the Effective Time, the Surviving Corporation shall, and Parent shall cause the Surviving Corporation to, continue to maintain in effect for a period of at least six years from and after the Effective Time the D&O Insurance in place as of the date hereof with terms, conditions, retentions and limits of liability that are at least as favorable as provided in the Company's existing policies as of the date hereof, or the Surviving Corporation shall, and Parent shall cause the Surviving Corporation to, use reasonable best efforts to purchase comparable D&O Insurance for such six-year period with terms, conditions, retentions and limits of liability that are at least as favorable as provided in the Company's existing policies as of the date hereof; provided, however, that in no event shall Parent or the Surviving Corporation be required to expend for such policies pursuant to this sentence an annual premium amount in excess of 300% of the annual premiums currently paid by the Company for such insurance; and provided, further, that if the annual premiums of such insurance coverage exceed such amount, the

Surviving Corporation shall obtain a policy with the greatest coverage available for a cost not exceeding such amount.

(c) If Parent or the Surviving Corporation or any of their respective successors or assigns shall (i) consolidate with or merge into any other corporation or entity and shall not be the continuing or surviving corporation or entity of such consolidation or merger or (ii) transfer all or substantially all of its properties and assets to any individual, corporation or other entity, then, and in each such case, proper provisions shall be made so that the successors and assigns of Parent or the Surviving Corporation shall assume all of the obligations set forth in this Section 6.11.

(d) The provisions of this Section 6.11 are intended to be for the benefit of, and shall be enforceable by, each of the Indemnified Parties.

(e) The rights of the Indemnified Parties under this Section 6.11 shall be in addition to any rights such Indemnified Parties may have under the certificate of incorporation, certificate of formation or bylaws of the Company or any of its Subsidiaries, or under any applicable Contracts or Laws. All rights to indemnification and exculpation from liabilities for acts or omissions occurring at or prior to the Effective Time and rights to advancement of expenses relating thereto now existing in favor of any Indemnified Party as provided in the certificate of incorporation, certificate of formation or bylaws of the Company or of any Subsidiary of the Company or any indemnification agreement between such Indemnified Party and the Company or any of its Subsidiaries, in each case as in effect on the date of this Agreement, shall survive the Merger and shall not be amended, repealed or otherwise modified in any manner that would adversely affect any right thereunder of any such Indemnified Party.

6.12. Takeover Statutes. If any Takeover Statute is or may become applicable to the Merger, the Company and its board of directors shall grant such approvals and take such actions as are necessary so that such transactions may be consummated as promptly as practicable on the terms contemplated by this Agreement and otherwise act to eliminate or minimize the effects of such statute or regulation on such transactions.

6.13. No Transfer or Encumbrance of Nonvoting Preferred Stock. Parent agrees that from the date hereof until the Closing, it shall not sell, pledge, dispose of, grant, transfer or encumber any of the shares of Nonvoting Preferred Stock, and shall not enter into any agreement to do any of the foregoing.

6.14. Transaction Litigation. In the event that any stockholder litigation related to this Agreement, the Merger or the other transactions contemplated by this Agreement is brought, or, to the Knowledge of the Company, threatened in writing, against the Company and/or the members of the board of directors of the Company after the date of this Agreement and prior to the Effective Time ("Transaction Litigation"), the Company shall promptly notify Parent of any such Transaction Litigation and shall keep Parent reasonably informed with respect to the status thereof.

The Company shall give Parent the opportunity to participate in the defense of any Transaction Litigation, and the Company shall not settle or agree to settle any Transaction Litigation, without Parent's prior written consent (which consent shall not be unreasonably withheld, delayed or conditioned).

6.15. Agreements Concerning Parent and Merger Sub.

(a) During the period from the date of this Agreement through the Effective Time, Merger Sub shall not engage in any activity of any nature except for activities related to or in furtherance of the Merger.

(b) Parent hereby guarantees the due, prompt and faithful payment, performance and discharge by Merger Sub of, and the compliance by Merger Sub with, all of the covenants, agreements, obligations and undertakings of Merger Sub under this Agreement in accordance with the terms of this Agreement, and covenants and agrees to take all actions necessary or advisable to ensure such payment, performance and discharge by Merger Sub hereunder. Parent shall, immediately following execution of this Agreement, approve this Agreement in its capacity as sole stockholder of Merger Sub in accordance with applicable Law and the articles of incorporation and bylaws of Merger Sub.

ARTICLE VII

Conditions

7.1. Conditions to Each Party's Obligation to Effect the Merger. The respective obligation of each party to effect the Merger is subject to the satisfaction or waiver at or prior to the Effective Time of each of the following conditions:

(a) Stockholder Approval. This Agreement shall have been duly adopted by holders of Shares constituting the Company Requisite Vote in accordance with applicable Law and the certificate of incorporation and bylaws of the Company.

(b) Regulatory Consents. The waiting period applicable to the consummation of the Merger under the HSR Act shall have expired or been earlier terminated; each of the FERC Approval, the Parent FERC Approval, the State Approvals and the FCC Approval shall have been obtained and be in effect, and any waiting period prescribed by Law with respect to such approvals before the Merger may be consummated shall have expired (the "Regulatory Approvals").

(c) Orders. No court or other Governmental Entity of competent jurisdiction shall have enacted, issued, promulgated, enforced or entered any Law (whether temporary, preliminary or permanent) that is in effect and restrains, enjoins or otherwise prohibits or makes illegal the consummation of the Merger (collectively, an "Order").

7.2. Conditions to Obligations of Parent and Merger Sub. The obligations of Parent and Merger Sub to effect the Merger are also subject to the satisfaction or waiver by Parent at or prior to the Effective Time of the following conditions:

(a) Representations and Warranties. (i) The representation and warranty of the Company set forth in Section 5.1(f)(i) shall be true and correct in all respects as of the date of this Agreement and as of the Closing Date as though made on and as of such time; (ii) the representations and warranties of the Company set forth in the first through fourth sentences of Section 5.1(b) shall be true and correct in all respects as of the Closing Date as though made on and as of such date and time (except for such inaccuracies that are not material), (iii) the representations and warranties of the Company set forth in Section 5.1(c), and Section 5.1(l) shall be true and correct in all material respects as of the Closing Date as though made on and as of such date and time (except to the extent that any such representation and warranty expressly speaks as of an earlier date, in which case such representation and warranty shall be true and correct as of such earlier date); (iv) the representations and warranties of the Company set forth in this Agreement (other than those described in clauses (i), (ii) and (iii) above) shall be true and correct (without giving effect to any "materiality" or "Company Material Adverse Effect" qualifiers contained therein) as of the Closing Date as though made on and as of such date and time (except to the extent that any such representation and warranty expressly speaks as of an earlier date, in which case such representation and warranty shall be true and correct as of such earlier date), provided, however, that notwithstanding anything herein to the contrary, the condition set forth in this Section 7.2(a)(iii) shall be deemed to have been satisfied even if any such representations and warranties of the Company are not so true and correct unless the failure of such representations and warranties of the Company to be so true and correct, individually or in the aggregate, has had or is reasonably likely to have a Company Material Adverse Effect; and (v) Parent shall have received at the Closing a certificate signed on behalf of the Company by a senior executive officer of the Company to the effect that such officer has read this Section 7.2(a) and the conditions set forth in this Section 7.2(a) have been satisfied.

(b) Performance of Obligations of the Company. The Company shall have performed in all material respects all obligations required to be performed by it under this Agreement at or prior to the Closing Date, and Parent shall have received a certificate signed on behalf of the Company by a senior executive officer of the Company to such effect.

(c) Regulatory Approvals. The regulatory consents referred to in Section 7.1(b), together with any Merger Laws, shall not, individually or in the aggregate, impose terms, conditions, liabilities, obligations, commitments or sanctions that constitute a Burdensome Condition.

7.3. Conditions to Obligation of the Company. The obligation of the Company to effect the Merger is also subject to the satisfaction or waiver by the Company at or prior to the Effective Time of the following conditions:

(a) Representations and Warranties. (i) The representations and warranties of Parent set forth in this Agreement shall be true and correct in all respects as of the Closing Date as though made on and as of such date and time (except to the extent that any such representation and warranty expressly speaks as of an earlier date, in which case such representation and warranty shall be true and correct as of such earlier date), provided, however, that notwithstanding anything herein to the contrary, the condition set forth in this Section 7.3(a)(i) shall be deemed to have been satisfied even if any such representations and warranties of Parent are not so true and correct unless the failure of such representations and warranties of Parent to be so true and correct, individually or in the aggregate, would prevent or materially delay the ability of Parent and Merger Sub to consummate the Merger and the other transactions contemplated by this Agreement and (ii) the Company shall have received at the Closing a certificate signed on behalf of Parent by a senior executive officer of Parent to the effect that such officer has read this Section 7.3(a) and the conditions set forth in this Section 7.3(a) have been satisfied.

(b) Performance of Obligations of Parent and Merger Sub. Each of Parent and Merger Sub shall have performed in all material respects all obligations required to be performed by it under this Agreement at or prior to the Closing Date, and the Company shall have received a certificate signed on behalf of Parent and Merger Sub by a senior executive officer of Parent to such effect.

ARTICLE VIII

Termination

8.1. Termination by Mutual Consent. This Agreement may be terminated and the Merger may be abandoned at any time prior to the Effective Time, whether before or after the adoption of this Agreement by the stockholders of the Company referred to in Section 7.1(a), by mutual written consent of the Company and Parent by action of their respective boards of directors.

8.2. Termination by Either Parent or the Company. This Agreement may be terminated and the Merger may be abandoned at any time prior to the Effective Time by action of the board of directors of either Parent or the Company if:

(a) the Merger shall not have been consummated by July 29, 2015 whether such date is before or after the date of adoption of this Agreement by the stockholders of the Company referred to in Section 7.1(a) (the "Termination Date"); provided, however, that if on July 29, 2015 (i) the condition set forth in Section 7.1(b) is not satisfied but all of the other conditions to Closing shall have been satisfied or waived (other than Section 7.2(c) or those conditions that by their nature are to be satisfied at the Closing) and the condition set forth in Section 7.1(b) remains capable of being satisfied and (ii) no final and non-appealable order or any Merger Law imposed by any Governmental Entity shall be in effect as of such date of determination that constitutes a Burdensome Condition, then the Termination Date may be extended until October 29, 2015 at the election of Parent or the Company by written notice to the other party (and such date shall then be the "Termination Date"). Notwithstanding the foregoing, the Company shall not have the right to terminate this Agreement pursuant to this Section 8.2(a) if Parent has the right to terminate this Agreement pursuant to Section 8.4(a);

(b) the adoption of this Agreement by the stockholders of the Company referred to in Section 7.1(a) shall not have been obtained at the Stockholders Meeting or at any adjournment or postponement thereof; or

(c) any Order permanently restraining, enjoining or otherwise prohibiting or making illegal the consummation of the Merger shall have become final and non-appealable (whether before or after the adoption of this Agreement by the stockholders of the Company referred to in Section 7.1(a)); provided, however, that the right to terminate this Agreement pursuant to this Section 8.2(c) shall not be available to any party whose failure to comply with any provision of this Agreement has been the cause of, or materially contributed to, either the imposition of such Order or the failure of such Order to be resisted, resolved, lifted or vacated, as applicable.

8.3. Termination by the Company. This Agreement may be terminated and the Merger may be abandoned by the Company:

(a) at any time prior to the time the Company Requisite Vote is obtained, if (i) the board of directors of the Company authorizes the Company, subject to complying with the terms of this Agreement (including Section 6.2), to enter into an Alternative Acquisition Agreement with respect to a Superior Proposal and the Company notifies Parent in writing that it intends to enter into such an agreement, attaching the most current version of such agreement to such notice; (ii) concurrently with the termination of this Agreement the Company enters into an Alternative Acquisition Agreement with respect to such Superior Proposal; and (iii) the Company prior to or concurrently with such termination pays to Parent in immediately available funds any fees required to be paid pursuant to Section 8.5; or

(b) if there has been a breach of any representation, warranty, covenant or agreement made by Parent or Merger Sub in this Agreement, or any such representation and warranty shall have become untrue after the date of this Agreement, such that Section 7.3(a) or 7.3(b) would not be satisfied and such breach or condition is not curable or, if curable, is not cured prior to the earlier of (i) 30 days after written notice thereof is given by the Company to Parent or (ii) two business days prior to the Termination Date.

8.4. Termination by Parent. This Agreement may be terminated and the Merger may be abandoned at any time prior to the Effective Time by Parent if:

(a) the board of directors of the Company or the Company (i) shall have effected a Change of Recommendation, (ii) shall have delivered a Recommendation Change Notice or (iii) shall have authorized the Company to enter into an Alternative Acquisition Agreement with respect to a Superior Proposal; or

(b) there has been a breach of any representation, warranty, covenant or agreement made by the Company in this Agreement, or any such representation and warranty shall have become untrue after the date of this Agreement, such that Section 7.2(a) or 7.2(b) would not be satisfied and such breach or condition is not curable or, if curable, is not cured prior to the earlier of (i) 30 days after written notice thereof is given by the Company to Parent or (ii) two business days prior to the Termination Date.

8.5. Effect of Termination and Abandonment.

(a) Except as provided in paragraphs (b), (c), (d) and (e) below, in the event of termination of this Agreement and the abandonment of the Merger pursuant to this Article VIII, this Agreement shall become void and of no effect with no liability to any Person on the part of any party hereto (or of any of its Representatives or Affiliates); provided, however, and notwithstanding anything in the foregoing to the contrary, that (i) except as otherwise provided herein, no such termination shall relieve any party hereto of any liability or damages to the other party hereto resulting from any willful or intentional material breach of this Agreement and (ii) the provisions set forth in this Section 8.5 and Section 9.1 shall survive the termination of this Agreement.

(b) In the event that:

(i) a bona fide Acquisition Proposal shall have been made or any Person shall have made or publicly announced or otherwise communicated to the Company, the board of directors of the Company or any Representatives of the Company an intention (whether or not conditional) to make an Acquisition Proposal with respect to the Company or any of its Subsidiaries (and such Acquisition Proposal or publicly announced intention shall not have been publicly withdrawn without qualification (A) no more than 75 days following the date such Acquisition Proposal has been made, with respect to any termination pursuant to Section 8.2(a), and (B) no fewer than five business days prior to, with respect to termination pursuant to Section 8.2(b), the date of the Stockholders Meeting) and thereafter this Agreement is terminated by either Parent or the Company pursuant to Section 8.2(a), 8.2(b) or 8.4(b);

(ii) this Agreement is terminated by Parent pursuant to Section 8.4(a); or

(iii) this Agreement is terminated by the Company pursuant to Section 8.3(a);

then the Company shall promptly pay Parent the Termination Fee, payable by wire transfer of immediately available funds, (A) in the case of clause (i), immediately prior to or substantially concurrent with the entry by the Company or any of its Subsidiaries into an Alternative Acquisition Agreement with respect to, or upon consummation or approval or recommendation to the Company’s stockholders of, an Acquisition Proposal (substituting “50%” for “15%” in the definition thereof) (whether or not such Acquisition

Proposal is the same Acquisition Proposal referred to in clause (i)) within 12 months of such termination, (B) in the case of clause (ii), in no event later than five days after the date of such termination or (C) in the case of the clause (iii), immediately prior to or concurrently with, but as a condition to, the termination of this Agreement. As used herein, "Termination Fee" shall mean a cash amount equal to (x) $259,000,000 or (y) $293,000,000 plus Parent Expenses if (i) the Company terminates this Agreement pursuant to Section 8.3(a) to enter into an Alternative Acquisition Agreement from a Bidding Party, (ii) Parent terminates this Agreement pursuant to Section 8.4(a) and the action by the board of directors of the Company that gave rise to Parent's termination under Section 8.4(a) was the result of an Acquisition Proposal by a Bidding Party or (iii) the Termination Fee becomes payable in accordance with Section 8.5(b)(i) and a Bidding Party made the Acquisition Proposal referred to in Section 8.5(b)(i) or the Acquisition Proposal referred to in Section 8.5(b)(i)(A). "Bidding Party" means any Person or group of Persons, or any of their respective controlled Affiliates, who has made an Acquisition Proposal on or after April 1, 2014 and prior to the date hereof. Notwithstanding anything to the contrary in this Agreement, the parties hereby acknowledge that in the event that the Termination Fee (together with the Parent Expenses) is paid by the Company pursuant to this Section 8.5(b), the Termination Fee (together with the Parent Expenses) shall be Parent's and Merger Sub's sole and exclusive remedy for monetary damages under this Agreement.

(c) If (i) the Company or Parent terminates this Agreement pursuant to Section 8.2(a) or 8.2(c) or (ii) the Company terminates this Agreement pursuant to Section 8.3(b) because of a failure by Parent to comply with its obligations under Section 6.5(d) or Section 6.5(e), and, in each of (i) and (ii), at the time of such termination, any of the conditions set forth in Sections 7.1(b), 7.1(c) or 7.2(c) shall not have been satisfied, and in addition, in the case of a termination under 8.2(c), at the time of termination a Governmental Entity shall have enacted such Order with respect to the Regulatory Approvals, and in each of (i) and (ii), at the time of such termination, all other conditions to the Closing set forth in Sections 7.1 and 7.2 shall have been satisfied or waived (other than those conditions that by their terms are to be satisfied at the Closing but which conditions would be satisfied or would be capable of being satisfied if the Closing Date were the date of such termination, or those conditions that have not been satisfied as a result of a breach by Parent) (each of (i) and (ii), a "Regulatory Termination"), then (A) Parent shall pay Company a termination fee equal to the Nonvoting Preferred Stock Purchase Price (the "Parent Termination Fee") which Parent Termination Fee shall be paid by Parent by means of the Company redeeming, as of the time of such termination, all of the outstanding shares of Nonvoting Preferred Stock for no consideration, and all of the outstanding shares of Nonvoting Preferred Stock will no longer be outstanding as of the time of such redemption, and (B) Parent shall promptly, but in no event later than five days after being notified of such by the Company, pay all of the documented out-of-pocket expenses incurred by the Company in connection with this Agreement and the transactions contemplated by this Agreement, up to a maximum amount of $40,000,000, payable by wire transfer of immediately available funds. Notwithstanding anything to the contrary in this Agreement, the parties hereby acknowledge that in the event that the Parent Termination Fee (together with the expense reimbursement contemplated by the immediately preceding sentence) is paid by Parent pursuant to this Section 8.5(c), the Parent Termination Fee (together with the expense reimbursement contemplated by the immediately preceding sentence) shall be the Company's sole and exclusive remedy for monetary damages under this Agreement, unless at the time of such termination Parent is in breach of its obligations under Section 6.5; provided, that the Company is not then in breach of Section 6.5.

(d) In the event this Agreement is terminated by the Company or Parent pursuant to this Article VIII other than pursuant to a Regulatory Termination, the Company will redeem, within five business days of such termination, all of the outstanding shares of Nonvoting Preferred Stock for an aggregate amount equal to the Nonvoting Preferred Stock Purchase Price, payable by the Company to Parent by wire transfer of immediately available funds, and all of the outstanding shares of Nonvoting Preferred Stock will no longer be outstanding as of the time of such redemption.

(e) In the event that this Agreement is terminated either (x) by Parent or the Company pursuant to Section 8.2(b) or (y) in the case of termination of this Agreement of the type contemplated by Section 8.5(b)(i) other than (i) pursuant to Section 8.2(a) and the Parent Termination Fee is payable or (ii) pursuant to Section 8.4(b) and (B) the Termination Fee is not then payable pursuant to Section 8.5(b), the Company shall promptly, but in no event later than five days after being notified of such by Parent, pay all of the documented out-of-pocket expenses incurred by Parent or Merger Sub in connection with this Agreement and the transactions contemplated by this Agreement up to a maximum amount of $40,000,000, payable by wire transfer of immediately available funds ("Parent Expenses"); provided, that the payment by the Company of Parent Expenses pursuant to this Section 8.5(e) shall be credited against any amount that may become payable pursuant to clause (x) of the definition of Termination Fee. The existence of circumstances which could require the Termination Fee to become subsequently payable by the Company pursuant to Section 8.5 shall not relieve the Company of its obligations to pay the Parent Expenses pursuant to this Section 8.5(e). The payment by the Company of Parent Expenses pursuant to this Section 8.5(e) shall not relieve the Company of any subsequent obligation to pay the Termination Fee pursuant to Section 8.5(b) (less a credit in the amount of Parent Expenses, if applicable).

(f) The parties acknowledge that the agreements contained in this Section 8.5 are an integral part of the transactions contemplated by this Agreement, and that, without these agreements, the parties would not enter into this Agreement; accordingly, if the Company fails to promptly pay the amounts due pursuant to Section 8.5(b) or Section 8.5(d), or Parent fails to promptly pay the amount due pursuant to Section 8.5(c), and, in order to obtain such payment, Parent or Merger Sub, on the one hand, or the Company, on the other hand, commences a suit that results in a judgment against the Company for the amounts set forth in Section 8.5(b) or Section 8.5(d), or any portion thereof, or a judgment against Parent for the amount set forth in Section 8.5(c) or any portion thereof, the Company shall pay to Parent or Merger Sub, on the one hand, or Parent shall pay to the Company, on the other hand, its costs and expenses (including attorneys' fees) in connection with such suit, together with interest on the amount of such amount or portion thereof at the Interest Rate in effect on the date such payment was required to be made through the date of payment.

ARTICLE IX

Miscellaneous and General

9.1. Survival. This Article IX and the agreements of the Company, Parent and Merger Sub contained in Article IV and Sections 6.9 (Employee Benefits), 6.10 (Expenses) and 6.11 (Indemnification; Directors' and Officers' Insurance) shall survive the consummation of the Merger. This Article IX and the agreements of the Company, Parent and Merger Sub contained in Section 6.10 (Expenses) and Section 8.5 (Effect of Termination and Abandonment) and the Confidentiality Agreement shall survive the termination of this Agreement. All other representations, warranties, covenants and agreements in this Agreement shall not survive the consummation of the Merger or the termination of this Agreement.

9.2. Modification or Amendment. Subject to the provisions of the applicable Laws, at any time prior to the Effective Time, the parties hereto may modify or amend this Agreement, by written agreement executed and delivered by duly authorized officers of the respective parties.

9.3. Waiver of Conditions. The conditions to each of the parties' obligations to consummate the Merger are for the sole benefit of such party and may be waived by such party in whole or in part to the extent permitted by applicable Laws. Any agreement on the part of a party to any such waiver shall be valid only if set forth in an instrument in writing signed by such party. The failure of any party to assert any of its rights hereunder or under applicable Law shall not constitute a waiver of such rights and, except as otherwise expressly provided herein, no single or partial exercise by any party of any of its rights hereunder precludes any other or further exercise of any such rights or any other rights hereunder or under applicable Law.

9.4. Counterparts. This Agreement may be executed in any number of counterparts, each such counterpart being deemed to be an original instrument, and all such counterparts shall together constitute the same agreement. This Agreement and any signed agreement or instrument entered into in connection with this Agreement, and any amendments or waivers hereto or thereto, to the extent signed and delivered by means of a facsimile machine or by email delivery of a ".pdf" format data file, shall be treated in all manner and respects as an original agreement or instrument and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

9.5. GOVERNING LAW AND VENUE; WAIVER OF JURY TRIAL; SPECIFIC PERFORMANCE.

(a) THIS AGREEMENT SHALL BE DEEMED TO BE MADE IN AND IN ALL RESPECTS SHALL BE INTERPRETED, CONSTRUED AND GOVERNED BY AND IN ACCORDANCE WITH THE LAW OF THE STATE OF DELAWARE WITHOUT REGARD TO THE CONFLICTS OF LAW PRINCIPLES THEREOF TO THE EXTENT THAT SUCH PRINCIPLES WOULD DIRECT A MATTER TO ANOTHER JURISDICTION. The parties hereby irrevocably submit to the exclusive personal jurisdiction of the Court of Chancery of the State of Delaware or to the extent such Court does not have jurisdiction, the United States District Court of the District of Delaware, solely in respect of the interpretation and enforcement of the provisions of this Agreement and of the documents referred to in this Agreement, and in respect of the transactions contemplated hereby, and hereby waive, and agree not to assert, as a defense in any action, suit or proceeding for the interpretation or enforcement hereof or of any such document, that it is not subject thereto or that such action, suit or proceeding may not be brought or is not maintainable in such courts or that such courts are an inconvenient forum, or that the venue of such courts may not be appropriate or that this Agreement or any such document may not be enforced in or by such courts, and the parties hereto irrevocably agree that all claims relating to such action, suit or proceeding shall be heard and determined in such a Delaware State or Federal court. The parties hereby consent to and grant any such court jurisdiction over the person of such parties and, to the extent permitted by Law, over the subject matter of such dispute and agree that mailing of process or other papers in connection with any such action, suit or proceeding in the manner provided in Section 9.6 shall be valid, effective and sufficient service thereof.

(b) EACH PARTY ACKNOWLEDGES AND AGREES THAT ANY CONTROVERSY WHICH MAY ARISE UNDER THIS AGREEMENT IS LIKELY TO INVOLVE COMPLICATED AND DIFFICULT ISSUES, AND THEREFORE EACH SUCH PARTY HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVES ANY RIGHT SUCH PARTY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY ACTION, SUIT OR PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT, OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT. EACH PARTY CERTIFIES AND ACKNOWLEDGES THAT (i) NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF ANY ACTION, SUIT OR PROCEEDING, SEEK TO ENFORCE THE FOREGOING WAIVER, (ii) EACH PARTY UNDERSTANDS AND HAS CONSIDERED THE IMPLICATIONS OF THIS WAIVER, (iii) EACH PARTY MAKES THIS WAIVER VOLUNTARILY, AND (iv) EACH PARTY HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 9.5.

(c) The parties agree that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms or were otherwise breached. It is accordingly agreed that the parties shall be entitled to an injunction or injunctions to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement in the Court of Chancery of the State of Delaware, this being in addition to any other remedy to which such party is entitled at law or in equity.

9.6. Notices. Any notice, request, instruction or other document to be given hereunder by any party to the others shall be in writing and delivered personally or sent by registered or certified mail, postage prepaid, by facsimile, email or overnight courier:

If to Parent or Merger Sub:

10 S. Dearborn
Corporate Headquarters, 54th Floor
Chicago, IL 60603
Attention: General Counsel
Email: darryl.bradford@exeloncorp.com
Fax: (312) 394-2368

with a copy to:

Kirkland & Ellis LLP
655 Fifteenth Street, N.W.
Washington, D.C. 20005
Attention: George P. Stamas
Fax: (202) 879-5200
Email: george.stamas@kirkland.com

If to the Company:

701 Ninth Street, N.W.
Washington, DC 20068
Attention: Kevin C. Fitzgerald
Email: kcfitzgerald@pepcoholdings.com
Fax: (202) 331-6485

with a copy to:

Sullivan & Cromwell LLP
125 Broad Street
New York, NY 10004
Attention: Joseph B. Frumkin
Audra D. Cohen
Fax: (212) 558-3588
Email: frumkinj@sullcrom.com
cohena@sullcrom.com

or to such other persons or addresses as may be designated in writing by the party to receive such notice as provided above. Any notice, request, instruction or other document given as provided above shall be deemed given to the receiving party upon actual receipt, if delivered personally; three business days after deposit in the mail, if sent by registered or certified mail; upon confirmation of successful transmission, if sent by facsimile or email (provided that if given by facsimile or email such notice, request, instruction or other document shall be followed up within one business day by dispatch pursuant to one of the other methods described herein); or on the next business day after deposit with an overnight courier, if sent by an overnight courier.

9.7. Entire Agreement. This Agreement (including any exhibits hereto), the Company Disclosure Letter, the Parent Disclosure Letter, the Subscription Agreement, the Confidentiality Agreement, dated March 7, 2014, between Parent and the Company (provided that the Confidentiality Agreement shall not be deemed to prevent Parent from exercising its rights under this Agreement) (as may be amended from time to time, the "Confidentiality Agreement") and the other agreements entered into in connection with preserving the confidentiality of information, constitute the entire agreement, and supersede all other prior agreements, understandings, representations and warranties both written and oral, among the parties, with respect to the subject matter hereof. EACH PARTY HERETO AGREES THAT, EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES CONTAINED IN THIS AGREEMENT, NEITHER PARENT AND MERGER SUB NOR THE COMPANY MAKES OR RELIES ON ANY OTHER REPRESENTATIONS, WARRANTIES OR INDUCEMENTS, AND EACH HEREBY DISCLAIMS ANY OTHER REPRESENTATIONS, WARRANTIES OR INDUCEMENTS, EXPRESS OR IMPLIED, AS TO THE ACCURACY OR COMPLETENESS OF ANY OTHER INFORMATION, MADE BY, OR MADE AVAILABLE BY, ITSELF OR ANY OF ITS REPRESENTATIVES, WITH RESPECT TO, OR IN CONNECTION WITH, THE NEGOTIATION, EXECUTION OR DELIVERY OF THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY, NOTWITHSTANDING THE DELIVERY OR DISCLOSURE TO THE OTHER OR THE OTHER'S REPRESENTATIVES OF ANY DOCUMENTATION OR OTHER INFORMATION WITH RESPECT TO ANY ONE OR MORE OF THE FOREGOING.

9.8. No Third Party Beneficiaries. Except as provided in Section 6.11 (Indemnification; Directors' and Officers' Insurance) only, Parent and the Company hereby agree that their respective representations, warranties and covenants set forth herein are solely for the benefit of the other party hereto, in accordance with and subject to the terms of this Agreement, and this Agreement is not intended to, and does not, confer upon any Person other than the parties hereto any rights or remedies hereunder, including the right to rely upon the representations and warranties set forth herein. The parties hereto further agree that the rights of third party beneficiaries under Section 6.11 shall not arise unless and until the Effective Time occurs. The representations and warranties in this Agreement are the product of negotiations among the parties hereto and are for the sole benefit of the parties hereto. Any inaccuracies in such representations and warranties are subject to waiver by the parties hereto in accordance with Section 9.3

without notice or liability to any other Person. In some instances, the representations and warranties in this Agreement may represent an allocation among the parties hereto of risks associated with particular matters regardless of the knowledge of any of the parties hereto. Consequently, Persons other than the parties hereto may not rely upon the representations and warranties in this Agreement as characterizations of actual facts or circumstances as of the date of this Agreement or as of any other date.

9.9. Obligations of Parent and of the Company. Whenever this Agreement requires a Subsidiary of Parent to take any action, such requirement shall be deemed to include an undertaking on the part of Parent to cause such Subsidiary to take such action. Whenever this Agreement requires a Subsidiary of the Company to take any action, such requirement shall be deemed to include an undertaking on the part of the Company to cause such Subsidiary to take such action and, after the Effective Time, on the part of the Surviving Corporation to cause such Subsidiary to take such action.

9.10. Transfer Taxes. All transfer, documentary, sales, use, stamp, registration and other such Taxes and fees (including penalties and interest) incurred in connection with the Merger shall be paid by Parent and Merger Sub when due.

9.11. Definitions. Each of the terms set forth in Annex A is defined in the Section of this Agreement set forth opposite such term.

9.12. Severability. The provisions of this Agreement shall be deemed severable and the invalidity or unenforceability of any provision shall not affect the validity or enforceability of the other provisions hereof. If any provision of this Agreement, or the application thereof to any Person or any circumstance, is invalid or unenforceable, (a) a suitable and equitable provision shall be substituted therefor in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid or unenforceable provision and (b) the remainder of this Agreement and the application of such provision to other Persons or circumstances shall not be affected by such invalidity or unenforceability, nor shall such invalidity or unenforceability affect the validity or enforceability of such provision, or the application thereof, in any other jurisdiction.

9.13. Interpretation; Construction. (a) The table of contents and headings herein are for convenience of reference only, do not constitute part of this Agreement and shall not be deemed to limit or otherwise affect any of the provisions hereof. Where a reference in this Agreement is made to a Section or Exhibit, such reference shall be to a Section of or Exhibit to this Agreement unless otherwise indicated. Whenever the words "include," "includes" or "including" are used in this Agreement, they shall be deemed to be followed by the words "without limitation."

(b) The parties have participated jointly in negotiating and drafting this Agreement. In the event that an ambiguity or a question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the parties, and no presumption or burden of proof shall arise favoring or disfavoring any party by virtue of the authorship of any provision of this Agreement.

(c) Each party here has or may have set forth information in its respective Disclosure Letter in a section thereof that corresponds to the section of this Agreement to which it relates. The fact that any item of information is disclosed in a Disclosure Letter to this Agreement shall not be construed to mean that such information is required to be disclosed by this Agreement.

9.14. Assignment. This Agreement shall not be assignable by operation of law or otherwise; provided, however, that, prior to the mailing of the Proxy Statement to the Company's stockholders, Parent may designate, by written notice to the Company, another wholly-owned direct or indirect Subsidiary to be a Constituent Corporation in lieu of Merger Sub, in which event all references herein to Merger Sub shall be deemed references to such other Subsidiary, except that all representations and warranties made herein with respect to Merger Sub as of the date of this Agreement shall be deemed representations and warranties made with respect to such other Subsidiary as of the date of such designation; provided that any such designation shall not impede or delay the consummation of the Merger or otherwise materially impede the rights of the stockholders of the Company under this Agreement. Any purported assignment in violation of this Agreement is void.

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officers of the parties hereto as of the date first written above.

PEPCO HOLDINGS, INC.

By: ______________________________
Name: Joseph M. Rigby
Title: Chairman of the Board, President and Chief Executive Officer

EXELON CORPORATION

By: ______________________________
Name: Christopher M. Crane
Title: President and Chief Executive Officer

PURPLE ACQUISITION CORP.

By: ______________________________
Name: Darryl M. Bradford
Title: President

ANNEX A

DEFINED TERMS

EXHIBIT A

Form of Certificate of Incorporation of the Surviving Corporation

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Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF INCORPORATION OF "PURPLE ACQUISITION CORP.", FILED IN THIS OFFICE ON THE TWENTY-EIGHTH DAY OF APRIL, A.D. 2014, AT 3:54 O'CLOCK P.M.

A FILED COPY OF THIS CERTIFICATE HAS BEEN FORWARDED TO THE NEW CASTLE COUNTY RECORDER OF DEEDS.

Jeffrey W. Bullock, Secretary of State

5523877 8100

140528064

AUTHENTICATION: 1325827

DATE: 04-28-14

State of Delaware
Secretary of State
Division of Corporations
Delivered 03:56 PM 04/28/2014
FILED 03:54 PM 04/28/2014
SRV 140528064 - 5523877 FILE

CERTIFICATE OF INCORPORATION

OF

PURPLE ACQUISITION CORP.

The undersigned natural person of the age of eighteen years or more for the purpose of organizing a corporation for conducting the business and promoting the purposes hereafter stated, under the provisions and subject to the requirements of the laws of the State of Delaware (particularly Chapter 1, Title 8 of the Delaware Code and the acts amendatory thereof and supplemental thereto, and known, identified, and referred to as the "General Corporation Law of the State of Delaware"), hereby certifies that:

ARTICLE FIRST:

The name of the corporation is Purple Acquisition Corp. (hereafter the "Corporation").

ARTICLE SECOND:

The address of the Corporation's registered office in the State of Delaware is 2711 Centerville Road, Suite 400, Wilmington, Delaware, 19808, County of New Castle. The name of the registered agent at such address is the Corporation Service Company.

ARTICLE THIRD:

The nature of the business or purposes to be conducted or promoted is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of the State of Delaware.

ARTICLE FOURTH:

The total number of shares of stock which the Corporation has the authority to issue is One Thousand (1,000) shares of Common Stock, with a par value of $0.01 per share.

ARTICLE FIFTH:

The name and address of the sole incorporator is as follows:

NAME:	**ADDRESS:**
Donna M.McClurkin-Fletcher	% Kirkland & Ellis LLP 655 Fifteenth Street, NW Washington, DC 20005

ARTICLE SIXTH:

The Corporation is to have perpetual existence.

ARTICLE SEVENTH:

In furtherance and not in limitation of the powers conferred by statute, the board of directors of the Corporation is expressly authorized to make, alter or repeal the Bylaws of the Corporation.

ARTICLE EIGHTH:

Meetings of stockholders may be held within or without the State of Delaware, as the Bylaws of the Corporation may provide. The books of the Corporation may be kept outside the State of Delaware at such place or places as may be designated from time to time by the board of directors or in the Bylaws of the Corporation. Election of directors need not be by written ballot unless the Bylaws of the Corporation so provide.

ARTICLE NINTH:

To the fullest extent permitted by the General Corporation Law of the State of Delaware, as the same exists or may hereafter be amended, a director of this Corporation shall not be liable to the Corporation or its stockholders for monetary damages for a breach of fiduciary duty as director. Any repeal or modification of this ARTICLE NINTH shall not adversely affect any right or protection of a director of the Corporation existing at the time of such repeal or modification.

ARTICLE TENTH:

The Corporation may, to the fullest extent permitted by Section 145 of the General Corporation Law of the State of Delaware, as the same may be amended and supplemented from time to time, indemnify any and all persons whom it shall have power to indemnify under said section from and against any and all of the expenses, liabilities or other matters referred to in or covered by said section, and the indemnification provided for herein shall not be deemed exclusive of any other rights to which a person indemnified may be entitled under any Bylaw, agreement, vote of stockholders or disinterested directors or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office, and shall continue as to a person who has ceased to be a director, officer, employee or agent and shall inure to the benefit of the heirs, executors and administrators of such a person.

ARTICLE ELEVENTH:

The Corporation expressly elects not to be governed by Section 203 of the General Corporation Law of the State of Delaware.

ARTICLE TWELFTH:

The Corporation reserves the right to amend, alter, change or repeal any provision contained in this certificate of incorporation in the manner now or hereafter prescribed herein and by the laws of the State of Delaware, and all rights conferred upon stockholders herein are granted subject to this reservation.

I, the undersigned, being the sole incorporator hereinbefore named, for the purpose of forming a corporation pursuant to the General Corporation Law of the State of Delaware, do make and file this certificate, hereby declaring and certifying that the facts herein stated are true, and accordingly, have hereunto set my hand this 28th day of April, 2014.

/s/ Donna M. McClurkin-Fletcher

Donna M. McClurkin-Fletcher, Sole Incorporator

EXHIBIT B

Regulatory Commitments

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Regulatory Commitments

The Company and Parent agree (a) that the applications submitted to the Governmental Entities with respect to the Merger shall include the information concerning the Merger, the Company and its Subsidiaries and Parent and its Subsidiaries required by applicable Law, (b) that such applications and any amendments or supplements thereto shall include such agreements or commitments as the Company and Parent agree are advisable to obtain prompt approval of such applications, (c) that such applications and any amendments or supplements thereto submitted to the Delaware Public Service Commission, the District of Columbia Public Service Commission, the Maryland Public Service Commission and the New Jersey Board of Public Utilities (collectively, the "State Commissions") shall include the commitments and agreements set forth below to the extent applicable to such jurisdictions and (d) that neither the Company nor Parent shall agree to, or accept, any additional or different agreements, commitments or conditions in connection with the Merger pursuant to any settlement or otherwise with any State Commission or any other Person without the prior written consent of the Company or Parent, as applicable, which consent shall not be unreasonably withheld, conditioned or delayed.

1. *Commitments Generally*. Parent affirms its support of each commitment set forth below that is made by the Company, Potomac Electric Power Company ("Pepco"), Delmarva Power & Light Company ("Delmarva Power") or Atlantic City Electric Company ("ACE"), as applicable, and Parent commits to cooperate with and support the Company in fulfilling and causing each of Pepco, Delmarva Power and ACE to fulfill each such commitment following the consummation of the Merger.

2. *The Merger*
    a. None of Pepco, Delmarva Power or ACE will seek to recover any acquisition premium or transaction costs in rates.
    b. None of Pepco, Delmarva Power or ACE will incur or assume any debt, including the provision of guarantees or collateral support, directly related to the Merger.

3. *Rates and Costs*
    a. Pepco, Delmarva Power and ACE will collectively provide tangible customer benefits with an aggregate value of $100 million, calculated to be at least $50 per distribution customer of Pepco, Delmarva Power and ACE.

4. *Reliability; Quality of Service*
    a. Each of Pepco, Delmarva Power and ACE commits to continue to implement its current plan to improve system reliability, and to improve upon each of their respective reliability targets. In the event that system reliability does not achieve increased performance levels, each utility will propose to suffer financial penalties as will be described in the applications for approval of the Merger to the State Commissions.
    b. Each of Parent and the Company commits to cause Pepco to continue to implement its District of Columbia undergrounding project as currently planned.

5. *Local Presence*
    a. As detailed in the applications for approval of the Merger to State Commissions following completion of the Merger:
        i. The Company will maintain the headquarters of the the Company system, with appropriate levels of senior management, at Edison Place in the District of Columbia.
        ii. Pepco will maintain its local operational headquarters in the District of Columbia at Edison Place.
        iii. Delmarva Power will maintain in place the New Castle Regional Office (NCRO).
        iv. ACE will maintain in place the Atlantic Regional Office at Mays Landing.
        v. Exelon Board, Committee or Subsidiary Board meetings or Leadership meetings will be periodically held in the District of Columbia.

6. *Labor and Employees*
    a. Each of Pepco, Delmarva Power and ACE will honor all existing collective bargaining agreements.
    b. Upon Approval of the transaction and for at least the first two years following consummation of the transaction, Parent shall not permit a net reduction, due to involuntary attrition as a result of the transaction integration process, in the employment levels at Pepco, Delmarva Power or ACE and shall provide current and former employees at Pepco, Delmarva Power and ACE compensation and benefits that are at least as favorable in the aggregate as the compensation and benefits provided to those employees immediately before the date of the Merger Agreement.
    c. The Company and Pepco, Delmarva Power, and ACE will continue their commitments to workforce diversity.

7. *Supplier Diversity*
    a. Each of Pepco, Delmarva Power and ACE will honor and maintain its commitment to existing supplier diversity programs.

8. *Low-Income Assistance*
    a. Each of Pepco, Delmarva Power and ACE will maintain and promote programs that provide assistance to low-income customers.

9. *Charitable Contributions and Community Initiatives*
    a. The Company and its subsidiaries will maintain aggregate charitable contributions and community support in the service territory of the Company system at Company's and its subsidiaries' 2013 levels, and continue such charitable contributions and community support at such levels for at least ten years following completion of the Merger, as will be described in more detail in the applications for approval of the Merger.

10. *Energy Efficiency*

a. The Company and its subsidiaries will maintain and promote existing energy efficiency and demand response programs.

11. Jurisdiction over Parent and its Affiliates

a. Parent submits to the jurisdiction of each State Commission for all matters related to the Merger and the enforcement of these commitments.
b. Parent submits to the jurisdiction of each applicable State Commission for matters relating to affiliate transactions between Pepco, Delmarva Power or ACE, as applicable on the one hand, and Parent and its other affiliates, on the other hand, and will cause each of its affiliates that supplies goods or services to Pepco, Delmarva Power or ACE to submit to the jurisdiction of each applicable State Commission for matters relating to the provision or cost of such goods or services to Pepco, Delmarva Power or ACE.

12. Organization; Financial Integrity; Ring-Fencing

a. Customers of Pepco, Delmarva Power and ACE will be protected from business and financial risk exposures associated with Parent's unregulated operations and activities through appropriate ring fencing provisions involving the placement of a bankruptcy-remote special purpose entity as the Parent subsidiary holding the equity interests in the Company, as will be described in more detail in the applications for approval of the Merger.
b. Parent and the Company will commit to implement the following ring-fencing arrangements for at least five years following completion of the Merger absent permission from the state commissions to act otherwise:
    i. Each of Pepco, Delmarva Power and ACE will maintain its separate existence and its separate franchises and privileges.
    ii. Each of Pepco, Delmarva Power and ACE will maintain separate books and records.
    iii. Each of Pepco, Delmarva Power and ACE will commit that all books and records of it pertaining to its operations in each of the jurisdictions in which it has regulated operations will be available for inspection and examination by each applicable State Commission with jurisdiction over such operations.
    iv. Each of Pepco, Delmarva Power and ACE will maintain separate debt so that none will be responsible for the debts of affiliated companies and preferred stock, if any, and will maintain its own corporate and debt credit rating as well as ratings for long-term debt and preferred stock.
    v. Maintenance of common equity ratio:
        - Pepco will maintain at least a common equity ratio consistent with the common equity ratios accepted in recent rate cases by the District of Columbia Public Service Commission and the Maryland Public Service Commission for Pepco.
        - Delmarva Power will maintain at least a common equity ratio consistent with the common equity ratios accepted in recent rate cases by the Delaware Public Service Commission and the Maryland Public Service Commission for Delmarva Power.

- ACE will maintain at least a common equity ratio consistent with the common equity ratios accepted in recent rate cases by the New Jersey Board of Public Utilities for ACE.

13. Affiliate Transactions

a. Parent commits to comply and to cause Pepco, Delmarva Power and ACE and other affiliates of Parent to comply with the statutes and regulations applicable to Pepco, Delmarva Power and ACE regarding affiliate transactions.
b. Parent commits that each applicable State Commission may examine accounting records of its affiliates that are the basis for charges to Pepco, Delmarva Power or ACE to determine the reasonableness of allocation factors used by Parent to assign costs to Pepco, Delmarva Power and ACE and amounts subject to allocation and direct charges.

EXHIBIT C

Form of Certificate of Designation for Nonvoting Preferred Stock

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CERTIFICATE OF DESIGNATION

OF

SERIES A NON-VOTING NON-CONVERTIBLE PREFERRED STOCK

OF

PEPCO HOLDINGS, INC.

Pursuant to Section 151 of the
General Corporation Law of the State of Delaware

Pepco Holdings, Inc., a Delaware corporation (the "Company"), hereby certifies that:

1. The Restated Certificate of Incorporation of the Company (the "Certificate of Incorporation") fixes the total number of shares of all classes of capital stock that the Company shall have the authority to issue at four hundred million (400,000,000) shares of common stock, par value $0.01 per share, and forty million (40,000,000) shares of preferred stock, par value $0.01 per share.

2. The Certificate of Incorporation expressly grants to the Board of Directors of the Company (the "Board of Directors") authority to provide for the issuance of the shares of preferred stock in series, and to establish from time to time the number of shares to be included in each such series and to fix the designation, preferences, privileges, voting powers and other rights of the shares of each such series and the qualifications, limitations or restrictions thereon.

3. The following resolution was adopted by action duly taken by the Board of Directors on April 29, 2014:

RESOLVED, that, pursuant to Article IV, Section C, of the Restated Certificate of Incorporation of the Company, the Board hereby authorizes the issuance of the Preferred Stock and the designation, preferences, privileges, voting powers and other rights of the shares of such Preferred Stock and the qualifications, limitations or restrictions thereon are as set forth in the certificate of designations establishing the Preferred Stock (the "Certificate of Designations"):

Section 1. Designation.

The designation of the series of preferred stock shall be "Series A Non-Voting Non-Convertible Preferred Stock" (the "Series A Preferred Stock"). Each share of Series A Preferred Stock shall be identical in all respects to every other share of Series A Preferred Stock. Series A Preferred Stock will rank equally with Parity Stock, if any, will rank senior to Junior Stock and will rank junior to Senior Stock, if any, with respect to the distribution of assets in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company.

Section 2. Number of Shares.

The number of authorized shares of Series A Preferred Stock shall be 18,000. That number from time to time may be decreased (but not below the number of shares of Series A Preferred Stock then outstanding) by further resolution duly adopted by the Board of Directors, or any duly authorized committee thereof and by the filing of a certificate pursuant to the provisions of the General Corporation Law of the State of Delaware stating that such reduction has been so authorized. The Company shall have the authority to issue fractional shares of Series A Preferred Stock. Shares of Series A Preferred Stock that are redeemed, purchased or otherwise acquired by the Company shall be canceled and shall revert to authorized but unissued shares of preferred stock undesignated as to series.

Section 3. Definitions. As used herein with respect to Series A Preferred Stock:

"Affiliate" of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For the purposes of this definition, "control" when used with respect to any specified Person, means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

"Board of Directors" has the meaning set forth in the recitals above.

"Business Day" means any weekday that is not a legal holiday in New York, New York and is not a day on which banking institutions in New York, New York are authorized or required by law or regulation to be closed.

"Common Stock" means the common stock of the Company, par value $0.01 per share, or any other shares of the capital stock of the Company into which such shares of common stock shall be reclassified or changed.

"Dividend Payment Date" has the meaning set forth in Section 4(a).

"Dividend Period" has the meaning set forth in Section 4(a).

"Dividend Record Date" has the meaning set forth in Section 4(a).

"Holder" means the Person in whose name the shares of the Series A Preferred Stock are registered, which may be treated by the Company and, if applicable, any transfer agent, registrar and paying agent as the absolute owner of the shares of Series A Preferred Stock for the purpose of making payment and for all other purposes.

"Junior Stock" means the Common Stock and any other class or series of stock of the Company now existing or hereafter authorized over which Series A Preferred Stock has preference or priority in the payment of dividends or in the distribution of assets on any voluntary or involuntary liquidation, dissolution or winding up of the Company.

"Liquidation Preference Amount" means $10,000.

"Merger Agreement" means the Agreement and Plan of Merger, dated as of April 29, 2014, by and among the Company, Exelon Corporation, a Pennsylvania corporation, and Purple Acquisition Corp., a Delaware corporation and wholly-owned subsidiary of Exelon Corporation.

"Other Merger Agreement Termination Event" means any termination of the Merger Agreement that is not a Regulatory Termination (as such term is defined in the Merger Agreement).

"Parity Stock" means any class or series of stock of the Company hereafter authorized that ranks equally with the Series A Preferred Stock in the payment of dividends and in the distribution of assets on any liquidation, dissolution or winding up of the Company.

"Person" means a legal person, including any individual, corporation, estate, partnership, joint venture, association, joint-stock company, limited liability company or trust.

"Redemption Event" has the meaning set forth in Section 4(a).

"Regulatory Failure Merger Agreement Termination Event" means the occurrence of a Regulatory Termination (as such term is defined in the Merger Agreement).

"Senior Stock" means any class or series of stock of the Company now existing or hereafter authorized which has preference or priority over the Series A Preferred Stock as to the payment of dividends or in the distribution of assets on any voluntary or involuntary liquidation, dissolution or winding up of the Company.

"Series A Preferred Stock" has the meaning set forth in Section 1.

Section 4. Dividends.

(a) **Rate.** Holders shall be entitled to receive, if, as and when declared by the Board of Directors, or any duly authorized committee thereof, but only out of assets legally available therefor, cumulative, non-participating cash dividends on the Liquidation Preference Amount per share of Series A Preferred Stock at the rate per annum specified below, and no more, payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year; provided, however, if any such day is not a Business Day, then payment of any dividend otherwise payable on that date will be made on the next succeeding day that is a Business Day, unless that day falls in the next calendar year, in which case payment of such dividend will occur on the immediately preceding Business Day (in either case, without any interest or other payment in respect of such delay) (each such day on which dividends are payable a "Dividend Payment Date"). The period from and including the date of issuance of the Series A Preferred Stock or any Dividend Payment Date to, but excluding, the next Dividend Payment Date is a "Dividend Period." Dividends on each share of Series A Preferred Stock will accrue daily on the

Liquidation Preference Amount per share (as from the date on which a Holder acquires such share of Series A Preferred Stock until the occurrence of a Regulatory Failure Merger Agreement Termination Event, an Other Merger Agreement Termination Event, or any redemption pursuant to Section 6(a)(i) (each, a "Redemption Event") at a rate per annum equal to 0.1% (one-tenth of one percent). If, on any Dividend Payment Date, the Company fails to pay dividends in respect of the Series A Preferred Stock equal to all dividends on the Series A Preferred Stock accrued but unpaid as of such date, the accrued but unpaid dividends on the Series A Preferred Stock shall nonetheless accumulate and compound (at a rate per annum equal to 0.1% (one-tenth of one percent)) on such Dividend Payment Date and shall remain accumulated, compounding dividends at such 0.1% rate, until paid pursuant hereto. The record date for payment of dividends on the Series A Preferred Stock will be the fifteenth day of the calendar month in which the Dividend Payment Date falls or such other record date fixed by the Board of Directors, or any duly authorized committee thereof, that is not more than 30 nor less than 10 days prior to such Dividend Payment Date (each, a "Dividend Record Date"). Any such day that is a Dividend Record Date will be a Dividend Record Date whether or not such day is a Business Day. The amount of dividends payable will be computed on the basis of a 360 day year of twelve 30 day months. As from the date and time of a Redemption Event, any pending dividend payments in respect of the Series A Preferred Stock shall be canceled and no further dividends in respect of the Series A Preferred Stock shall be payable.

(b) **Priority of Dividends.** Such dividends payable in cash, stock or otherwise, as may be determined by the Board of Directors or a duly authorized committee thereof, may be declared and paid on any Senior Stock, Junior Stock and Parity Stock from time to time out of any assets legally available for such payment, and Holders will not be entitled to participate in those dividends. Neither the declaration nor the paying by the Company of, nor the failure by the Company to declare or pay, dividends to the Holders of the Series A Preferred Stock shall be a pre-condition to, prohibit or otherwise have any effect on, the declaration or payment of any dividend in respect of any Senior Stock, Junior Stock or Parity Stock or any other class or series of authorized stock of the Company.

Section 5. Liquidation Rights.

(a) **Liquidation.** In the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company, Holders shall be entitled, out of assets legally available therefor, before any distribution or payment out of the assets of the Company may be made to or set aside for the holders of any Junior Stock and subject to the rights of the holders of any class or series of securities ranking senior to or on parity with Series A Preferred Stock upon liquidation and the rights of the Company's depositors and other creditors, to receive in full a liquidating distribution in the amount of the Liquidation Preference Amount per share, plus any any unpaid accrued and accumulated dividends thereon from the last dividend payment date to, but excluding, the date of the liquidation, dissolution or winding up, if and to the extent declared. Holders shall not be entitled to any further payments in the event of any such voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company other than what is expressly provided for in this Section 5.

(b) **Partial Payment.** If the assets of the Company are not sufficient to pay in full the liquidation preference plus any dividends which have been declared but not yet paid to all

Holders and all holders of any Parity Stock, the amounts paid to the Holders and to the holders of all Parity Stock shall be *pro rata* in accordance with the respective aggregate liquidating distributions to which they would otherwise be entitled.

(c) **Residual Distributions.** If the respective aggregate liquidating distributions to which all Holders and all holders of any Parity Stock are entitled have been paid, the holders of Junior Stock shall be entitled to receive all remaining assets of the Company according to their respective rights and preferences.

(d) **Merger, Consolidation and Sale of Assets Not Liquidation.** For purposes of this Section 5, unless waived by Holders of a majority of the shares of Series A Preferred Stock, the sale, conveyance, exchange or transfer (for cash, shares of stock, securities or other consideration) of all or substantially all of the property and assets of the Company shall be deemed a voluntary or involuntary dissolution, liquidation or winding up of the affairs of the Company, and the merger, consolidation or any other business combination transaction of the Company into or with any other corporation or person or the merger, consolidation or any other business combination transaction of any other corporation or person into or with the Company other than the Merger contemplated by the Merger Agreement shall be deemed to be a voluntary or involuntary dissolution, liquidation or winding up of the affairs of the Company.

Section 6. Redemption.

(a) **Optional Redemption.**

(i) *Optional Redemption at Any Time.* The Company, at the option of its Board of Directors, or any duly authorized committee thereof, may, at any time, redeem out of funds legally available therefor, in whole or in part, the shares of Series A Preferred Stock at the time outstanding, upon notice given as provided in Section 6(c) below, at a redemption price equal to the Liquidation Preference Amount per share, *plus* any unpaid accrued and accumulated dividends thereon.

(ii) *Optional Redemption in Connection with a Regulatory Failure Merger Agreement Termination Event.* In the event that a Regulatory Failure Merger Agreement Termination Event occurs, the Company, at the option of its Board of Directors, or any duly authorized committee thereof, may redeem all of the shares of Series A Preferred Stock at the time outstanding, which redemption shall be effective as of the time of such Regulatory Failure Merger Agreement Termination Event, at a redemption price equal to $0.01 per share. As of the time of such Regulatory Failure Merger Agreement Termination Event, all of the shares of Series A Preferred Stock shall be considered redeemed and no longer outstanding. For the avoidance of doubt, the delivery, pursuant to the Merger Agreement, of a notice of the Regulatory Termination (as such term is defined in the Merger Agreement) of the Merger Agreement shall be sufficient notice to the Holders of the redemption of the Series A Preferred

Stock pursuant to this Section 6(a)(ii) and shall be effective immediately upon delivery.

(b) **Mandatory Redemption in Connection with an Other Merger Agreement Termination Event.** In the event that an Other Merger Agreement Termination Event occurs, the Company shall promptly provide notice as contemplated by Section 6(c) below and redeem out of funds legally available therefor, in whole, the shares of Series A Preferred Stock at the time outstanding, at a redemption price equal to the Liquidation Preference Amount per share, *plus* any unpaid accrued and accumulated dividends thereon.

(c) **Notice of Redemption.** Notice of any redemption of shares of Series A Preferred Stock pursuant to Section 6(a)(i) or Section 6(b) shall be mailed by first class mail, postage prepaid, addressed to the Holders of such shares to be redeemed at their respective last addresses appearing on the stock register of the Company. Such mailing shall be at least five business days and not more than 30 days before the date fixed for redemption. Any notice mailed as provided in this Section 6(c) shall be conclusively presumed to have been duly given, whether or not the Holder receives such notice, but failure duly to give such notice by mail, or any defect in such notice or in the mailing thereof, to any Holder of shares of Series A Preferred Stock designated for redemption shall not affect the validity of the proceedings for the redemption of any other shares of Series A Preferred Stock. Each notice shall state:

(i) the redemption date;

(ii) the number of shares of Series A Preferred Stock to be redeemed;

(iii) the redemption price;

(iv) the place or places where the certificates for such shares are to be surrendered for payment of the redemption price; and

(v) that dividends on the shares to be redeemed will cease to accrue on the redemption date.

Section 7. Conversion Rights.

Series A Preferred Stock shall not be convertible into Senior Stock, Junior Stock or any other security, and does not otherwise have any conversion rights.

Section 8. Voting Rights.

(a) Except as otherwise provided in Section 8(b) hereof or as otherwise required by law, the holders of Series A Preferred Stock shall have no right or power to vote on any matter submitted to a vote of stockholders.

(b) The Company shall not (by amendment, merger, consolidation or otherwise), without the prior approval, by vote or written consent, of the holders of a majority of the Series

A Preferred Stock then outstanding, voting as a separate class, (i) increase the authorized number of shares of Series A Preferred Stock or (ii) amend or repeal the Certificate of Incorporation in any manner which adversely affects the rights, preferences or voting powers of the Series A Preferred Stock.

Section 9. Preemption.

The Holders shall not have any rights of preemption.

Section 10. Rank.

Notwithstanding anything set forth in the Certificate of Incorporation or this Certificate of Designation to the contrary, the Board of Directors, or any duly authorized committee thereof, without the vote of the Holders, may authorize and issue additional shares of Junior Stock, Parity Stock or any class or series of Senior Stock or any other securities ranking senior to the Series A Preferred Stock as to dividends and/or the distribution of assets upon any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company.

Section 11. Repurchase.

Subject to the limitations imposed herein, the Company may purchase and sell Series A Preferred Stock from time to time to such extent, in such manner, and upon such terms as the Board of Directors, or any other duly authorized committee thereof, may determine; provided, however, that the Company shall not use any of its funds for any such purchase when there are reasonable grounds to believe that the Company is, or by such purchase would be, rendered insolvent.

Section 12. Unissued or Reacquired Shares.

Shares of Series A Preferred Stock not issued or which have been issued and redeemed or otherwise purchased or acquired by the Company shall be restored to the status of authorized but unissued shares of preferred stock without designation as to series.

Section 13. No Sinking Fund.

Shares of Series A Preferred Stock are not subject to the operation of a sinking fund.

Section 14. Transfer Agent, Registrar and Paying Agent.

The Company shall be the initial transfer agent, registrar and paying agent for the Series A Preferred Stock and may, at its discretion, appoint a substitute, transfer agent, registrar or paying agent, provided that the Company provides notice of such substitution by first-class mail, postage prepaid, to the Holders.

Section 15. Replacement Certificates.

If physical certificates are issued, the Company shall replace any mutilated certificate at the Holder's expense upon surrender of that certificate to the Company. The Company shall replace certificates that become destroyed, stolen or lost at the Holder's expense upon delivery to the Company of satisfactory evidence that the certificate has been destroyed, stolen or lost, together with any indemnity that may be required by the Company.

Section 16. Transfer Taxes.

The Company shall pay any and all stock transfer, documentary, stamp and similar taxes that may be payable in respect of any issuance or delivery of shares of Series A Preferred Stock or certificates representing such shares. The Company shall not, however, be required to pay any such tax that may be payable in respect of any transfer involved in the issuance or delivery of shares of Series A Preferred Stock in a name other than that in which the shares of Series A Preferred Stock with respect to which such shares or other securities are issued or delivered were registered, or in respect of any payment to any Person other than a payment to the registered holder thereof, and shall not be required to make any such issuance, delivery or payment unless and until the Person otherwise entitled to such issuance, delivery or payment has paid to the Company the amount of any such tax or has established, to the satisfaction of the Company, that such tax has been paid or is not payable.

Section 17. Notices.

All notices referred to herein shall be in writing, and, unless otherwise specified herein, all notices hereunder shall be deemed to have been given upon the earlier of receipt thereof or three Business Days after the mailing thereof if sent by registered or certified mail (unless first class mail shall be specifically permitted for such notice under the terms of this Certificate of Designation) with postage prepaid, addressed: (i) if to the Company, to its office at 701 Ninth Street, N.W., Washington, D.C. 20068 (Attention: Corporate Secretary) or other agent of the Company designated as permitted by this Certificate of Designation or (ii) if to any Holder, to, 10 S. Dearborn, Corporate Headquarters, 54th Floor, Chicago, IL 60603 (Attention: General Counsel).

Section 18. Derivative Actions.

The shares of Series A Preferred Stock shall not confer upon its Holders any right to bring derivative actions against or on behalf of the Company.

Section 19. Restrictions On Transfer.

The Series A Preferred Stock is non-transferrable, except as expressly permitted pursuant to the redemption provisions of Section 6. No Holder may offer, reoffer, sell, assign, transfer, pledge, encumber, hypothecate, grant or otherwise dispose of any of the shares of Series A Preferred Stock, and no Holder shall enter into any agreement to do any of the foregoing. Any transfer or purported transfer of Series A Preferred Stock in violation of the foregoing restrictions shall be null, void and of no effect.

Section 20. Other Rights.

The shares of Series A Preferred Stock shall not have any powers, preferences or relative, participating, optional or other special rights, other than as specifically set forth herein or in the Certificate of Incorporation.

IN WITNESS WHEREOF, this Certificate of Designation has been executed on behalf of the Company by its Chairman of the Board, President and Chief Executive Officer this 29th day of April, 2014.

PEPCO HOLDINGS, INC.

By: ______________________________
Name: Joseph M. Rigby
Title: Chairman of the Board, President and Chief Executive Officer

Exhibit A

FORM OF
SERIES A NON-VOTING NON-CONVERTIBLE PREFERRED STOCK

FACE OF SECURITY

THIS SECURITY HAS NOT BEEN AND WILL NOT BE REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED (TOGETHER WITH THE RULES AND REGULATIONS PROMULGATED THEREUNDER, THE "SECURITIES ACT"), OR THE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES OR ANY OTHER JURISDICTION.

THE SERIES A PREFERRED STOCK IS NON-TRANSFERRABLE, EXCEPT AS EXPRESSLY PERMITTED PURSUANT TO THE REDEMPTION PROVISIONS OF SECTION 6 OF THE CERTIFICATE OF DESIGNATION, AS THE SAME MAY BE AMENDED FROM TIME TO TIME. NO HOLDER MAY OFFER, REOFFER, SELL, ASSIGN TRANSFER, PLEDGE, ENCUMBER, HYPOTHECATE, GRANT OR OTHERWISE DISPOSE OF ANY OF THE SHARES OF SERIES A PREFERRED STOCK, AND NO HOLDER SHALL ENTER INTO ANY AGREEMENT TO DO ANY OF THE FOREGOING. ANY TRANSFER OR PURPORTED TRANSFER OF SERIES A PREFERRED STOCK IN VIOLATION OF THE FOREGOING RESTRICTIONS SHALL BE NULL, VOID AND OF NO EFFECT.

Certificate Number_______ Number of Shares of Series A Preferred Stock______

Series A Non-Voting Non-Convertible Preferred Stock
(par value $0.01 per share)
(liquidation preference U.S.$10,000 per share)
of
PEPCO HOLDINGS, INC.

Pepco Holdings, Inc., a Delaware corporation (the "Company"), hereby certifies that [ ] (the "Holder") is the registered owner of [ ] fully paid and non-assessable preferred shares of the Company designated the Series A Non-Voting Non-Convertible Preferred Stock, with a par value of $0.01 per share and a liquidation preference of U.S.$10,000 per share (the "Series A Preferred Stock"). The Series A Preferred Stock is non-transferrable, except as expressly permitted pursuant to the redemption provisions of Section 6 of the Certificate of Designation (as defined below). No Holder may offer, reoffer, sell, assign, transfer, pledge, encumber, hypothecate, grant or otherwise dispose of any of the shares of Series A Preferred Stock, and no Holder shall enter into any agreement to do any of the foregoing. Any transfer or purported transfer of Series A Preferred Stock in violation of the foregoing restrictions shall be null, void and of no effect. The designations, rights, privileges, restrictions, preferences and other terms and provisions of the Series A Preferred Stock represented hereby are issued and shall in all respects be subject to the provisions of the Certificate of Designation dated April [29], 2014 as the same may be amended from time to time (the "Certificate of Designation"). Capitalized terms used herein but not defined shall have the meaning given them in the Certificate of Designation. The Company will provide a copy of the Certificate of Designation to a Holder without charge upon written request to the Company at its principal place of business.

Reference is hereby made to select provisions of the Series A Preferred Stock set forth on the reverse hereof, and to the Certificate of Designation, which select provisions and the Certificate of Designation shall for all purposes have the same effect as if set forth at this place.

Upon receipt of this certificate, the Holder is bound by the Certificate of Designation and is entitled to the benefits thereunder.

IN WITNESS WHEREOF, this certificated has been executed on behalf of the Company by its [*Title*] this [29th] day of April, 2014.

PEPCO HOLDINGS, INC.

By: ________________________________
Name:
Title:

REVERSE OF SECURITY

Dividends on each share of Series A Preferred Stock shall be payable at the rate provided in the Certificate of Designation.

The shares of Series A Preferred Stock are not convertible into any other securities and bear no other conversion rights.

The shares of Series A Preferred Stock shall be redeemable at option of the Company in the manner and accordance with the terms set forth in the Certificate of Designation.

The shares of Series A Preferred Stock are subject to mandatory redemption by the Company in the manner and accordance with the terms set forth in the Certificate of Designation.

The Series A Preferred Stock is non-transferrable, except as expressly permitted pursuant to the redemption provisions of Section 6 of the Certificate of Designation. No Holder may offer, reoffer, sell, assign, transfer, pledge, encumber, hypothecate, grant or otherwise dispose of any of the shares of Series A Preferred Stock, and no Holder shall enter into any agreement to do any of the foregoing. Any transfer or purported transfer of Series A Preferred Stock in violation of the foregoing restrictions shall be null, void and of no effect.

The shares of Series A Preferred Stock shall not have voting rights or consent rights on any matter except in each case as required by Delaware law.

The shares of Series A Preferred Stock shall not confer upon its Holders any right to bring derivative actions against or on behalf of the Company.

The Company shall furnish without charge to each holder who so requests the powers, designations, preferences and relative, participating, optional or other special rights of each class or series of share capital issued by the Company and the qualifications, limitations or restrictions of such preferences and/or rights.

EXHIBIT 4

PHI Pre-Merger

LEGEND:

PHI = Pepco Holdings, Inc.

PEPCO = Potomac Electric Power Company

Conectiv = Conectiv LLC

DPL = Delmarva Power & Light Company

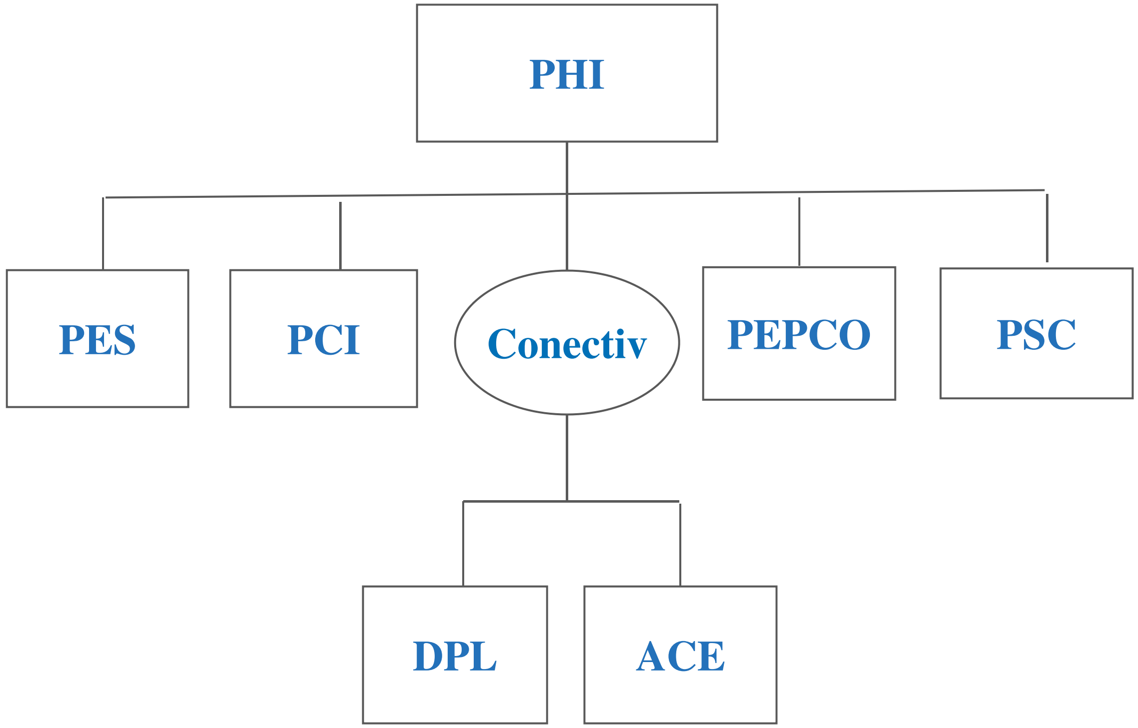
ACE = Atlantic City Electric Company

PCI = Potomac Capital Investment Corporation

PES = Pepco Energy Services, Inc.

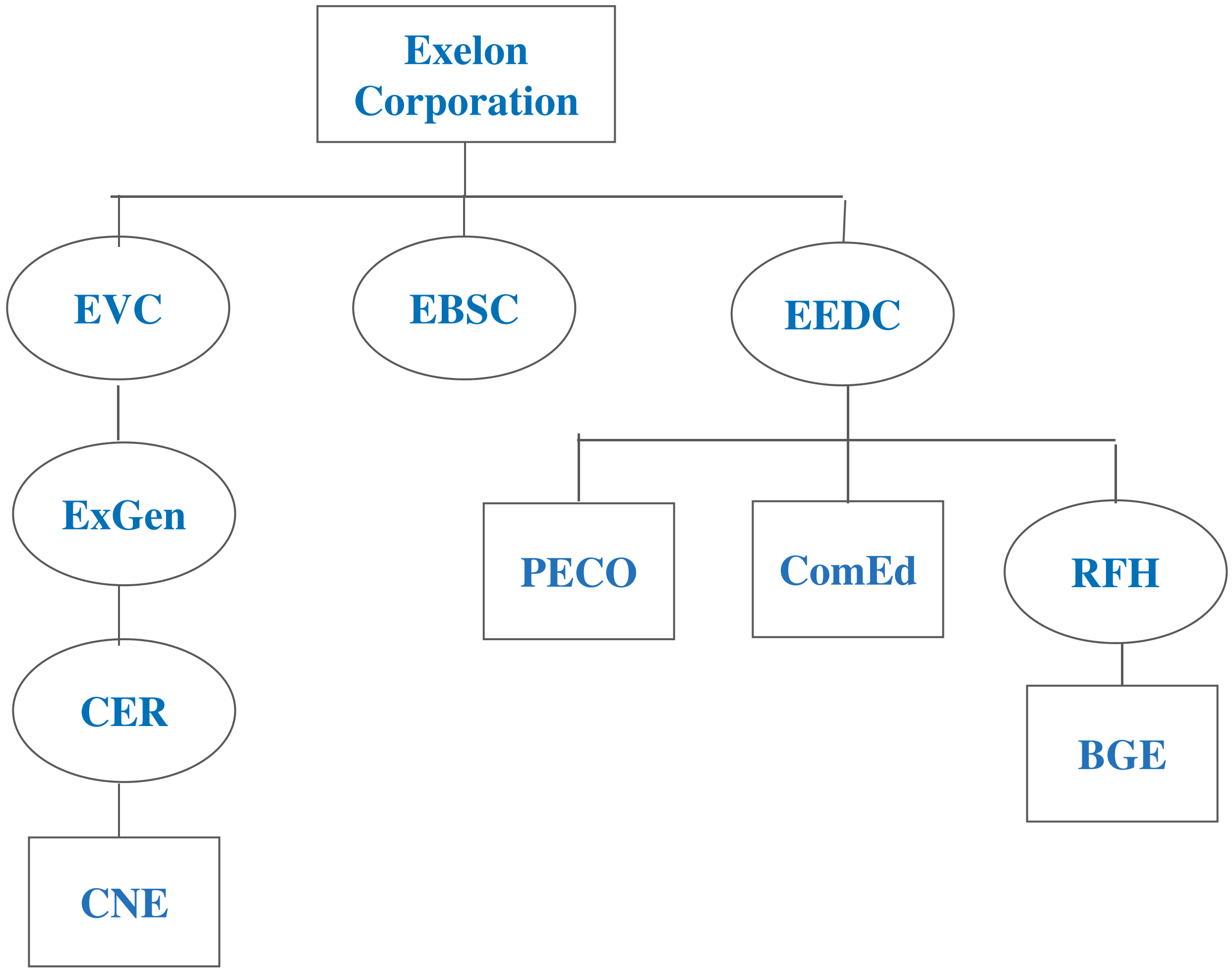
PSC = PHI Service Company

NOTE: (i) Additional subsidiaries are not shown; (ii) circles are disregarded entities and squares are corporations for income tax purposes



Exelon.

Exelon Pre-Merger



LEGEND:

EVC = Exelon Ventures Company

ExGen = Exelon Generation Company

CER = Constellation Energy Resources

CNE = Constellation New Energy Inc.

EBSC – Exelon Business Services Company

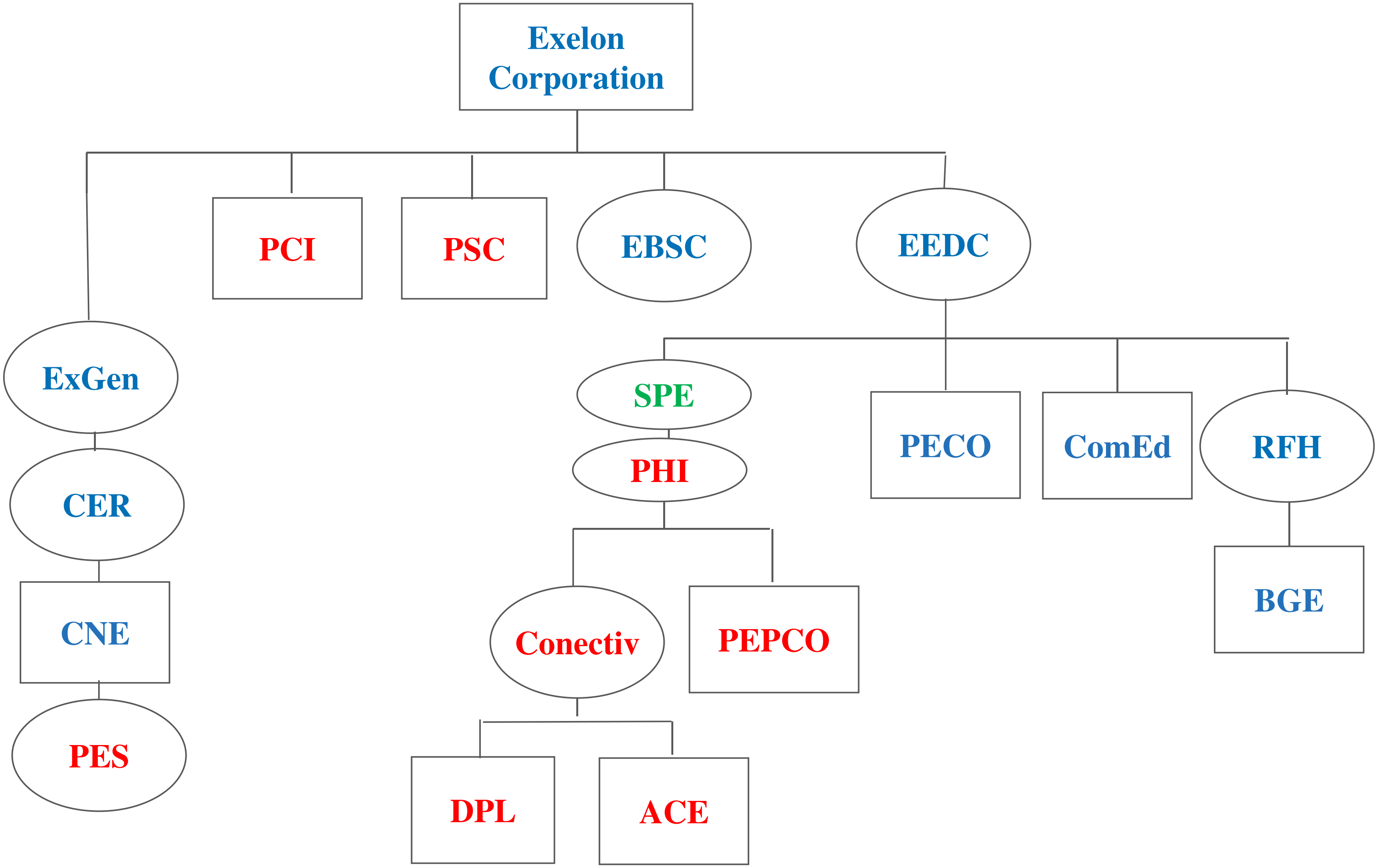
EEDC = Exelon Energy Delivery Company

RFH = RF Holdco

NOTE: (i) Additional subsidiaries are not shown; (ii) circles are disregarded entities and squares are corporations for income tax purposes; and (iii) EVC is scheduled to be dissolved in 2014.

Exelon.

Post-Merger Organization



Former subsidiaries of PHI are shown in red

EXHIBIT 5

EXHIBIT 5 – JOINT APPLICANTS' COMMITMENTS

Commitment 1 – Merger Impact on Rates

Potomac Electric Power Company ("Pepco") will not seek recovery in rates of: (1) any acquisition premium associated with the Merger; or (2) any transaction costs incurred in connection with the Merger by Exelon Corporation ("Exelon"), Pepco Holdings, Inc. ("PHI"), or their subsidiaries. In addition, Pepco will not incur or assume any debt, including the provision of guarantees or collateral support, directly related to the Merger.

Commitment 2 – Customer Investment Fund

After consummation of the Merger, Exelon will establish a $14 million Exelon-funded Customer Investment Fund to be used across Pepco's District of Columbia service territory at the District of Columbia Public Service Commission's discretion. This fund represents a benefit of at least $50 per District of Columbia distribution customer of Pepco.

Commitment 3 – Reliability and Quality of Service

Pepco commits to continue to implement its current plan to improve system reliability and to improve upon each of its reliability targets. Specifically, Exelon commits to Pepco achieving the following reliability performance levels by 2020, based on a three-year historical average calculated over the 2018-2020 period: (1) the System Average Interruption Frequency Index will not exceed 0.54 interruptions; and (2) the System Average Interruption Duration Index will not exceed 107 minutes. In the event that system reliability does not achieve increased performance levels, Pepco will be subject to financial penalties as described in the direct testimony of Carim V. Khouzami. PHI and Exelon commit to cause Pepco to continue to implement its District of Columbia undergrounding project as currently planned.

Commitment 4 – Local Presence

PHI will maintain its headquarters, with appropriate levels of senior management, in the District of Columbia. Pepco will maintain its local operational headquarters in the District of Columbia. Exelon Board of Directors' meetings and other leadership meetings will be periodically held in the District of Columbia.

Commitment 5 – Labor, Employment and Compensation

Pepco will honor all existing collective bargaining agreements. Upon approval of the Merger and for at least the first two years following consummation of the Merger, Exelon: (1) will not permit a net reduction, due to involuntary attrition as a result of the Merger integration process, in the employment levels at Pepco, and (2) will provide current and former Pepco employees compensation and benefits that are at least as favorable in the aggregate as the compensation and benefits provided to those employees immediately before April 29, 2014. PHI and Pepco will also continue its commitments to workforce diversity.

Commitment 6 – Supplier Diversity

Pepco will honor and maintain its commitment to existing supplier diversity programs.

Commitment 7 – Low-Income Assistance

Pepco will maintain and promote programs that provide assistance to low-income customers.

Commitment 8 – Charitable Contributions and Community Initiatives

In the District of Columbia, Exelon and its subsidiaries shall, during the ten-year period following consummation of the Merger, provide at least an annual average of charitable contributions and traditional local community support that exceeds PHI's and Pepco's 2013 level.

Commitment 9 – Energy Efficiency

PHI and Pepco will maintain and promote existing energy efficiency and demand response programs.

Commitment 10 – Exelon's Consent to Jurisdiction

Exelon submits to the jurisdiction of the District of Columbia Public Service Commission for: (1) all matters related to the Merger and the enforcement of the commitments set forth herein; and (2) matters relating to affiliate transactions between Pepco and Exelon or its affiliates. Exelon will also cause each of its affiliates that supplies goods or services to Pepco to submit to the jurisdiction of the District of Columbia Public Service Commission for matters relating to the provision or costs of such goods or services to Pepco.

Commitment 11 – Corporate Organization, Financial Integrity and Ring-Fencing

A bankruptcy-remote special purpose entity will be established as the Exelon subsidiary holding the equity interests in PHI. In addition, Exelon and PHI commit to implement the following ring-fencing arrangements for at least five years following completion of the Merger, absent permission from the District of Columbia Public Service Commission to act otherwise: (1) Pepco will maintain its separate existence and its separate franchises and privileges; (2) Pepco will maintain separate books and records; (3) Pepco's books and records pertaining to its operations in the District of Columbia will be available for inspection and examination by the District of Columbia; (4) Pepco will maintain separate debt so that it will not be responsible for the debts of affiliate companies and preferred stock, if any, and Pepco will maintain its own corporate and debt credit rating, as well as ratings for long-term debt and preferred stock; and (5) Pepco will maintain a common equity ratio consistent with such ratios accepted in recent rate cases by the District of Columbia Public Service Commission.

Commitment 12– Affiliate Transactions

Exelon commits to comply and cause Pepco and other Exelon affiliates to comply with the statutes and regulations applicable to Pepco regarding affiliate transactions. Exelon also commits that the District of Columbia Public Service Commission may examine the accounting records of Exelon's affiliates that are the basis for charges to Pepco to determine the reasonableness of allocation factors used by Exelon to assign those costs and amounts subject to allocation and direct charges.

EXHIBIT 6

EXHIBIT 6

Proposed List of Issues[1]

(1) What are the Joint Applicants' estimates of the costs, benefits, and net savings associate with the merger?

(2) How will the costs and savings be measure, monitored, and demonstrated?

(3) What are the short and long-term effects of the merger on Pepco's prices charged to District of Columbia customers?[2]

(4) How will the merger affect employment at Pepco and PHI?

(5) Will the Commission's ability to regulate Pepco, or its regulated and unregulated subsidiaries, be impaired by the proposed merge, including gaining access to accounts and financial records?

(6) How, if at all, would the merger affect the ability or willingness of Pepco to provide standard offer or default service to customers in the District of Columbia?

(7) What effect, if any, will the merger have on the quality of customer electricity services in the District of Columbia?

(8) What will be the effect, if any, of the merger on the safety and reliability of providing electricity in the District of Columbia?

(9) What are the short and long-term effects of the merger on the distribution facilities of Pepco employed in serving District of Columbia customers?

(10) Are the reliability guarantees and associated penalty mechanisms proposed by the Joint Applicants reasonable, necessary and appropriate?[3]

(11) What safeguards, if any, should the Commission establish to ensure that PHI regulated subsidiaries (i.e., Pepco) do not subsidize unregulated subsidiaries, affiliates, or the overall corporate structure?

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[1] With the exception of Issue Nos. 15 and 16, the proposed list of issues are the issues that were designated by the Commission for consideration of the proposed merger in Formal Case No. 1002. The Company also proposing removing what was designated as Issue No. 14 - What authority will the Commission have over the issuance of securities by the parent companies?

[2] Issue No. 3 was modified to remove the reference to "price caps" which were in place at the time of consideration of Formal Case No. 1002.

[3] Issue No. 10 modified to reflect that the Company is making both a reliability guarantee and proposing an associated penalty mechanism.

(12) What will be the impact of the merger on local electricity competition in the District of Columbia?

(13) What impact, if any, will the merger of the Joint Applicants' transmission facilities operated by the PJM Interconnection LLC have on ratepayers in the District of Columbia?

(14) What effect will the merger have on the capital structure of the District of Columbia jurisdictional operations?

(15) What risks, costs, and benefits associate with Exelon's nuclear operations will District of Columbia customers be required to bear as a result of the merger?

(16) What impact will the merger, if any, have on plans to underground Pepco's distribution feeders in the District of Columbia?

EXHIBIT 7

GENERAL SERVICES AGREEMENT

BETWEEN

EXELON BUSINESS SERVICES COMPANY

AND

EXELON CORPORATION; EXELON ENERGY DELIVERY COMPANY, LLC; COMMONWEALTH EDISON COMPANY; PECO ENERGY COMPANY; EXELON VENTURES COMPANY, LLC; EXELON GENERATION COMPANY, LLC; EXELON ENTERPRISES COMPANY, LLC; UNICOM INVESTMENT INC.; AND THE SUBSIDIARIES, AFFILIATES AND ASSOCIATES OF EACH LISTED ENTITY.

THIS AGREEMENT, made and entered into this 1st day of January, 2001, by and between the following Parties: EXELON BUSINESS SERVICES COMPANY ("Services Company"), EXELON CORPORATION; EXELON ENERGY DELIVERY COMPANY, LLC; COMMONWEALTH EDISON COMPANY; PECO ENERGY COMPANY; EXELON VENTURES COMPANY, LLC; EXELON GENERATION COMPANY, LLC; EXELON ENTERPRISES COMPANY, LLC; UNICOM INVESTMENT INC; AND THE SUBSIDIARIES, AFFILIATES AND ASSOCIATES OF EACH LISTED ENTITY (collectively, the "Client Companies");

WITNESSETH:

WHEREAS, Client Companies, including EXELON CORPORATION, which is registered under the terms of the Public Utility Holding Company Act of 1935 (the "Act") and its other subsidiaries, affiliates and associates desire to enter into this agreement providing for the performance by Services Company for the Client Companies of certain services as more particularly set forth herein;

WHEREAS, Services Company is organized, staffed and equipped and has filed with the Securities and Exchange Commission ("the SEC") to be a subsidiary service company under Section 13 of the Act to render to EXELON CORPORATION, and other subsidiaries, affiliates and associates of EXELON CORPORATION, certain services as herein provided; and

WHEREAS, to maximize efficiency, and to achieve merger related savings, the Client Companies desire to avail themselves of the advisory, professional, technical and other services of persons employed or to be retained by Services Company, and to compensate Services Company appropriately for such services;

NOW, THEREFORE, in consideration of these premises and of the mutual agreements set forth herein, the Parties agree as follows:

Section 1. Agreement to Provide Services

Services Company agrees to provide to Client Companies, upon the terms and conditions set forth herein, the services hereinafter referred to and described in Section 2, at such times, for such period and in such manner as Client Companies may from time to time request. Except with respect to "Corporate Governance Services" as defined in Section 7 hereof, the Services Company shall perform only those services as are requested by the Client Companies. Services Company will keep itself and its personnel available and competent to provide to Client Companies such services so long as it is authorized to do so by the appropriate federal and state regulatory agencies. In providing such services, Services Company may arrange, where it deems appropriate, for the services of such experts, consultants, advisers and other persons with necessary qualifications as are required for or pertinent to the provision of such services.

Section 2. Services to be Provided

The services expected to be provided by Services Company hereunder may, upon request by a Client Company, include the services as set out in Schedule 2, attached hereto and made a part hereof. In addition to those identified in Schedule 2, Services Company shall provide such additional general or special services, whether or not now contemplated, as Client Companies may request from time to time and Services Company determines it is able to provide.

Notwithstanding the foregoing paragraph, no change in the organization of the Services Company, the type and character of the companies to be serviced, the factors for allocating costs to associate companies, or in the broad general categories of services to be rendered subject to Section 13 of the Act, or any rule, regulation or order thereunder, shall be made unless and until the Services Company shall first have given the SEC written notice of the proposed change not less than 60 days prior to the proposed effectiveness of any such change. If, upon the receipt of any such notice, the SEC shall notify the Services Company within the 60-day period that a question exists as to whether the proposed change is consistent with the provisions of Section 13 of the Act, or of any rule, regulation or order thereunder, then the proposed change shall not become effective unless and until the Services Company shall have filed with the SEC an appropriate declaration regarding such proposed change and the SEC shall have permitted such declaration to become effective.

Section 3. Changes in Parties

New direct or indirect subsidiaries, affiliates and associates of EXELON CORPORATION, which may come into existence after the effective date of this Services Agreement, may become additional Client Companies of Services Company and subject to this General Services Agreement. In addition, entities which are, as of the effective date of this General Services Agreement, direct or indirect subsidiaries, affiliates and associates of EXELON CORPORATION, may thereafter leave the holding company system, in which case they will no longer be subject to this General Services Agreement. The parties hereto shall make such changes in the scope and character of the services to be provided and the method of assigning, distributing or allocating costs of such services as may become necessary to achieve a fair and equitable assignment, distribution, or allocation of Services Company costs among associate companies taking into account both the new subsidiaries and the subsidiaries which have left the holding company system, subject to the provisions of Section 2 above.

Section 4. Compensation of Services Company

As compensation for the services to be rendered hereunder, Client Companies listed in Attachment A hereto, as revised from time to time, shall pay to Services Company all costs which reasonably can be identified and related to particular services provided by Services Company for or on Client Company's behalf (except as may otherwise be permitted by the SEC). All other Client Companies and their affiliates and associates (see Attachment B) shall pay to Services Company charges for services that are to be no less than cost (except as may otherwise be permitted by the SEC), insofar as costs can reasonably be identified and related by Services Company to its performance of particular services for or on behalf of Client Company.

The services described herein or contemplated to be provided hereunder shall be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The factors for assigning or allocating Services Company costs to Client Company, as well as to other associate companies, are set forth in Schedules 1 and 2 attached hereto. Attachments A and B and Schedules 1 and 2 are each expressly incorporated herein and made a part hereof.

Any charges to the Client Companies on account of use of capital shall reflect a reasonable and efficient capital structure.

Section 5. Securities and Exchange Commission Rules

It is the intent of the Parties that the determination of the costs as used in this Agreement shall be consistent with, and in compliance with, the rules and regulations of the SEC, as they now exist or hereafter may be modified by the Commission.

Section 6. Service Review

The parties shall review each service covered by this Agreement on an as needed basis, to assess the quality of the service and to determine the continued need therefor, and shall, subject to the provisions of Section 2 above, amend the scope of services, delete services entirely from this Agreement, and/or decline services which are not "Corporate Governance Services," as defined in Section 7 hereof, as they determine to be necessary or desirable.

Section 7. Corporate Governance Services.

Whether or not requested by the Client Companies, the Services Company may provide to all Client Companies, and Client Companies shall pay Services Company for, "Corporate Governance Services." Corporate governance consists of those activities and services reasonably determined to be necessary for the lawful and effective management of Exelon System businesses. Corporate Governance Services may be supplied from functions such as accounting, finance, executive, strategic planning, legal, human resources/benefits, audit, corporate communications and public affairs, environmental, health and safety, government affairs and policy, and investor relations. Corporate Governance Services may include, but are not limited to, the following: planning and project evaluation; finance and treasury; accounting and analysis; risk management; tax; shareholder and investor relations; merger and acquisition services; strategic planning; diversity; employee and labor relations; HR planning and development; compensation and benefits; legal services in the areas of securities, PUHCA, employment, regulatory, contract, litigation and intellectual property laws; legal and administrative support to the Board of Directors; environmental compliance activities; ethics and compliance programs; management services for compliance with Federal laws, regulations and other policy requirements, including relationship management with the U.S. Congress and Federal agencies; corporate communications; branding; corporate events; charitable support; community relations and communications to local organizations; and communications to employees.

Section 8. Payment

Payment shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of the companies involved. Invoices shall be prepared on a monthly basis for services provided hereunder.

Section 9. EXELON CORPORATION

Except as authorized by rule, regulation, or order of the SEC, nothing in this Agreement shall be read to permit EXELON CORPORATION, or any person employed by or acting for EXELON CORPORATION, to provide services for other Parties, or any companies associated with said Parties.

Section 10. Client Companies

Except as limited by law or order of the SEC, Client Companies, their subsidiaries, affiliates and associates may provide services described herein to other Client Companies, their subsidiaries, affiliates and associates on the same terms and conditions as set out for the Services Company.

Section 11. Effective Date and Termination

This Agreement is executed subject to the consent and approval of all applicable regulatory agencies, and if so approved in its entirety, shall be deemed effective from the date that the merger between PECO ENERGY COMPANY and UNICOM CORPORATION was consummated, and shall remain in effect from said date unless terminated by mutual agreement or by any Party giving at least 90 days' written notice to the other Parties prior to the beginning of any calendar year, each Party fully reserving the right to so terminate this Agreement.

This Agreement may also be terminated or modified to the extent that performance may conflict with any rule, regulation or order of the SEC adopted before or after the making of this Agreement. This Agreement shall be terminated with respect to any Client Company immediately upon such Client Company ceasing to be a member of the Exelon holding company system.

The Parties' obligations under this Agreement which by their nature are intended to continue beyond the termination or expiration of this Agreement shall survive such termination or expiration.

Section 12. Access to Records

Records will be maintained in accordance with 17 C.F.R. §257 and in any event no less than seven years following a transaction under this Agreement. The Client Company may request access to and inspect the accounts and records of the Services Company, provided that the scope of access and inspection is limited to accounts and records that are related to such transaction.

Section 13. Assignment

This Agreement and the rights hereunder may not be assigned without the mutual written consent of all Parties hereto.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and attested by their authorized officers as of the day and year first above written.

EXELON BUSINESS SERVICES COMPANY

By Ruth Ann M. Gillis

Ruth Ann M. Gillis
Title: President

EXELON CORPORATION,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES, AFFILIATES AND ASSOCIATES

By Barry Mitchell

J. Barry Mitchell
Title: Senior Vice President and Treasurer

EXELON ENERGY DELIVERY COMPANY, LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By Barry Mitchell

J. Barry Mitchell
Title: Vice President and Treasurer

COMMONWEALTH EDISON COMPANY,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By Barry Mitchell

J. Barry Mitchell
Title: Senior Vice President, Treasurer, and Chief Financial Officer

PECO ENERGY COMPANY,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By Barry Mitchell

J. Barry Mitchell
Title: Vice President, Treasurer, and Chief Financial Officer

EXELON VENTURES COMPANY LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By ______________________________
J. Barry Mitchell
Title: Vice President, Treasurer, and Chief Financial Officer

EXELON GENERATION COMPANY, LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By ______________________________
J. Barry Mitchell
Title: Vice President, Treasurer, and Chief Financial Officer

EXELON ENTERPRISES COMPANY, LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By ______________________________
J. Barry Mitchell
Title: Vice President and Treasurer

UNICOM INVESTMENT INC.,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By ______________________________
J. Barry Mitchell
Title: Chairman, President and Chief Executive Officer,
Director, Vice President and Treasurer

BALTIMORE GAS AND ELECTRIC COMPANY,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES
(effective March 12, 2012)

By ______________________________
Carim V. Khouzami
Title: Vice President, Chief Financial Officer and Treasurer

Attachment A

Commonwealth Edison Company

Commonwealth Edison Of Indiana, Inc.

PECO Energy Company

Exelon Generation Company, LLC

Baltimore Gas and Electric Company (effective March 12, 2012)

Any subsidiary involved in directly providing goods, construction or services to the foregoing companies

Attachment B

All other Client Companies and their affiliates and associates not referred to in Attachment A.

Service Agreement Schedule 1

<u>Allocation Ratios:</u>

General:

Direct charges shall be made so far as costs can be identified and related to the particular transactions involved without excessive effort or expense. Other elements of cost, including taxes, interest, other overhead, and compensation for the use of capital procured by the issuance of capital stock, shall be fairly and equitably allocated using the ratios set forth below.

Revenue Related Ratios:

Revenues
Sales - Units sold and/or transported
Number of Customers

Expenditure Related Ratios:

Total Expenditures
Operations and Maintenance Expenditures
Capital Expenditures
Service Company Billings
Service Company SLA Billings (Non-governance)

Labor/Payroll Related Ratios:

Labor / Payroll
Number of Employees

Units Related Ratios:

Usage (for example: CPU's, square feet , number of vendor invoice payments)
Consumption (for example: tons of coal, gallons of oil, MMBTU's)
Capacity (for example: nameplate generating capacity, peak load, gas throughput)
Other units related

Assets Related Ratios:

Total Assets
Current Assets
Gross Plant

Composite Ratios:

Total Average Assets and 12 months ended Gross Payroll
Modified Massachusetts Formula
Other composite ratios

Service Agreement Schedule 2

Services Including But Not Limited To:

General:

Direct charges shall be made so far as costs can be identified and related to the particular transactions involved without excessive effort or expense. Other elements of cost, including taxes, interest, other overhead, and compensation for the use of capital procured by the issuance of capital stock, shall be fairly and equitably allocated using the ratios set forth in Schedule 1.

Administrative & management services including but not limited to:

- accounting
  - bookkeeping
  - billing
  - accounts receivable
  - accounts payable
  - financial reporting
- audit
- claims
- communications
- customer operations
- customer services
- executive
- finance
- insurance
- information systems services
- investment advisory services
- legal
- library
- record keeping
- secretarial & other general office support
- real estate management
- security holder services
- tax
- treasury
- other administration & management services

Expected allocation ratios: Revenue Related, Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Personnel services including but not limited to:

recruiting
training & evaluation services
payroll processing
employee benefits administration & processing
labor negotiations & management
other personnel services

Expected allocation ratios: Labor/Payroll Related, Units Related, Composite

Purchasing services including but not limited to:

preparation & analysis of product specifications
requests for proposals & similar solicitations
vendor & vendor-product evaluations
purchase order processing
receipt, handling, warehousing and disbursement of purchased items contract negotiation & administration
inventory management & disbursement
other purchasing services

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Facilities management services including but not limited to:

office space
warehouse & storage space
transportation facilities (including dock & port, rail sidings and truck facilities)
repair facilities
manufacturing & production facilities
fixtures, office furniture & equipment

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Composite

Computer services including but not limited to:

computer equipment & networks
peripheral devices
storage media
software

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Communications services including but not limited to:

communications equipment
audio & video equipment
radio equipment
telecommunications equipment & networks
transmission & switching capability

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Machinery management services including but not limited to:

equipment
tools
parts & supplies

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Composite

Vehicle management services including but not limited to:

automobiles
trucks
vans
trailers
railcars
marine vessels
aircraft
transport equipment
material handling equipment
construction equipment

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Composite

Operational services including but not limited to:

drafting & technical specification, development & evaluation
consulting
engineering
environmental
safety
nuclear
construction

design
resource planning
economic & strategic analysis
research
testing
training
customer solicitation
support & other marketing related services
public & governmental relations
other operational services

Expected allocation ratios: Revenue Related, Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Exhibit B

Service Level Arrangement

Arrangement between __________________ Services Department and [Client Company]

Purpose

Governing Agreement

Term of Service

Scope of Services

Scope of Services

Service Responsibility Matrix

Services, Tasks		

Service Costing Schedule

Monthly Billing Table:

Service/Transaction	Estimated Monthly Billing

Performance Metrics & Performance Reporting

Signatures	
Manager Service Company	Name (Client) Title
____________________ ________ Signature Date	____________________ ________ Signature Date

Exhibit C

Project Charter

Mission:

Objective

-
-

Business Need / Expected Benefits

-

Project Approach

-
-
-

Measures of Success / Effectiveness

-
-

Project Team

- Sponsor -
- Responsible Director –
- Project Manager –
- Project Team –

High Level Schedule

Activity or Deliverable	Start Date	End Date

High Level Cost Estimate

Item	Cost

Major Risks and Issues

-

Assumptions and Constraints

-

Project Charter Authorizing Signatures

Name / Title	Signature	Date

EXHIBIT 8

EXHIBIT 8

Proposed Procedural Schedule

Event	**Date**
Pre-Hearing Conference	July 17, 2014
Supplemental Direct Testimony and supporting workpapers of Jt. Applicants	August 22, 2014
All Information Requests to Jt. Applicants regarding Application, Direct Testimony and Supplemental Direct Testimony	September 3, 2014
Responses to Information Requests to Jt. Applicants regarding Application, Direct Testimony and Supplemental Direct Testimony	September 13, 2014
Direct Testimony and supporting workpapers of OPC and Intervenors	October 10, 2014
All Information Requests to OPC and Intervenor Direct Testimony	October 17, 2014
Responses to Information Requests to OPC and Intervenors Direct Testimony	October 24, 2014
Settlement Conference	November 3, 2014
Filing of Rebuttal Testimony and supporting workpapers by Jt. Applicants	November 7, 2014
All Information Requests to Jt. Applicants re: Rebuttal Testimony	November 14, 2014
Responses to Information Requests to Jt. Applicants re: Rebuttal Testimony	November 21, 2014
Evidentiary Hearings Commence	December 8, 2014
Filing of Initial Briefs	January 8, 2015
Filing of Reply Briefs	January 22, 2015
Decision	April 22, 2015

C.M. CRANE
Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _________(A)

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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF CHRISTOPHER M. CRANE
FORMAL CASE NO. _____

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is Christopher M. Crane. My business address is 10 Dearborn Street, Chicago, Illinois 60603.

2. Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer of Exelon Corporation ("Exelon"). I became the Chief Executive Officer of Exelon in March 2012 upon the retirement of John W. Rowe.

3. Q. Please describe your professional and educational background.

A. I began my career in 1979 in the Engineering Department at the Comanche Peak Nuclear Station. From October 1981 to October 1988, I worked at the Palo Verde Nuclear Generating Station in a number of positions. From October 1988 to 1998, I worked for the Tennessee Valley Authority in progressively more responsible positions, including site vice president of the Brown's Ferry Nuclear Plant.

In 1998, I moved to Commonwealth Edison Company ("ComEd") to help improve the performance of that company's fleet of nuclear generating plants. From September 1998 to July 1999, I served as Vice President for Boiling Water Reactor Operations and played a major role in the ComEd nuclear program recovery. In July 1999, I was promoted to Senior Vice President of Nuclear

Operations. My responsibilities in that role expanded to include the daily operation and the regulatory and technical performance of all five ComEd nuclear plants.

In 2000, Unicom Corporation ("Unicom") and PECO Energy Company ("PECO") merged to form Exelon. In June 2003, I was promoted to Chief Operating Officer of Exelon Nuclear. My responsibilities in that role focused on the daily operations of Exelon's nuclear generating facilities. I was also president and Chief Executive Officer of AmerGen, the joint venture between Exelon and British Energy ("BE") that owned and operated three nuclear plants. I remained in that position until BE sold its interest to Exelon. In January 2004, I was promoted to President and Chief Nuclear Officer of Exelon and, in that capacity, oversaw strategy development as well as the daily operations of all of Exelon's nuclear generating facilities.

In 2007, I was promoted to Chief Operating Officer of Exelon Generation, which owns all of Exelon's generation resources. In 2008, I was promoted to President and Chief Operating Officer of Exelon. In that capacity, I directed a broad range of business initiatives, including acquisitions, and was responsible for transmission strategy, cost management, major capital programs, Exelon's nuclear up-rating program, generation asset optimization and the development of renewable energy projects.

As I previously explained, I became the President and Chief Executive Officer of Exelon in 2012 upon the retirement of Mr. Rowe.

I have held a senior reactor operator certification, studied electricity at New Hampshire Technical College, and attended Harvard Business School's Advanced Management Program. I am a member of the board, a member of the Executive Committee and one of the Vice Chairs of the Edison Electric Institute. I am Vice Chairman of the Institute of Nuclear Power Operations and Chairman of the Nuclear Energy Institute. I also serve on the Board of Governors of the World Association of Nuclear Operators ("WANO") and on the Board of Governors of WANO's Atlanta Center.

4. Q. Please identify your other community leadership roles.

A. I am a member of the Civic Committee of The Commercial Club of Chicago and a member of the Board of Trustees of the Rush University Medical Center. I am a director of the Museum of Science & Industry Chicago and of Get IN Chicago, an innovative public/private partnership with the mission of eliminating juvenile violence.

5. Q. Have you previously testified before a utility regulatory agency?

A. Yes. I submitted rebuttal testimony before the New Jersey Board of Public Utilities at BPU Docket No. EM05020106, which was the proceeding for approval of the proposed merger of Exelon and Public Service Enterprise Group, Inc. That merger was not consummated. More recently, I submitted direct and rebuttal testimony before the Public Service Commission of Maryland on behalf of the applicants in Case No. 9271, which was the proceeding for approval of the merger of Exelon and Constellation Energy Group, Inc. ("Constellation").

6. Q. What is the purpose of your direct testimony?

A. In Section II, I provide an overview of the proposed merger of Exelon and Pepco Holdings, Inc. ("PHI") ("Merger"), and explain how it will strengthen the combined company's utilities to better serve our customers. I also want to introduce Exelon, and the best way to do that is to describe its vision and core values, as I do in Section III of my testimony. As part of this discussion, I explain how our vision and core values align with those of PHI and why that alignment will facilitate the integration of our companies. In Section IV of my testimony, I explain why Exelon decided to merge with PHI and, in particular, why the Merger will help meet the challenges facing distribution utilities. In Section V, I provide an overview of the benefits the Merger will produce and explain why it is in the best interest of PHI's utilities, their customers and the communities they serve. As part of this discussion, I will explain Exelon's approach to achieving top-tier performance at reasonable cost through the rigorous application of best practices and a management philosophy that continuously challenges us to improve productivity and efficiency. In Section VI, I introduce other witnesses submitting direct testimony in support of the Merger.

II. OVERVIEW OF THE MERGER

7. Q. Please provide an overview of the Merger.

A. On April 29, 2014, Exelon and PHI entered into an Agreement and Plan of Merger ("Merger Agreement") with the approval of their respective Boards of Directors. When the Merger is consummated, PHI will become an indirect subsidiary of Exelon, and PHI's common stockholders will be entitled to receive

$27.25 per share in exchange for the PHI stock they hold. The terms of the Merger are discussed in greater detail in the direct testimony of Carim V. Khouzami.

8. Q. Will the Merger strengthen the PHI and Exelon utilities?

A. Yes, it will. I am confident that the Merger will create the premier Mid-Atlantic energy distribution utility system. Potomac Electric Power Company ("Pepco"), Delmarva Power & Light Company ("Delmarva Power") and Atlantic City Electric Company ("ACE") (collectively, the "PHI Utilities") will join an organization that includes three outstanding utilities – Baltimore Gas and Electric Company ("BGE"), ComEd and PECO– with proven track records of furnishing safe, reliable and efficient energy delivery service. Significantly, the PHI Utilities share Exelon's commitment to safety, operational excellence, customer service, environmental stewardship, and community service. These shared commitments establish a solid foundation for building strong, high-performing, post-Merger utilities. To cite one important example of how this will occur, the Merger will leverage the combined expertise of the PHI and Exelon utilities to enhance reliability at a reasonable cost. As Mark F. Alden explains in his direct testimony, the recent merger of Exelon and Constellation, which led to significant improvements in BGE's reliability metrics without increasing its capital or operating and maintenance ("O&M") budgets, demonstrates the many benefits that accrue from successfully integrating two outstanding organizations and the resultant sharing of best practices. Additionally, the PHI Utilities will join a larger enterprise and, in that way, gain access to a number of additional resources, including the financial strength of Exelon. They will also benefit from greater bargaining power throughout the supply chain and realize economies of scale at many levels within the post-Merger organization. As I will explain in more detail later in my testimony, the Merger will expand emergency response capabilities, drive operational excellence, and facilitate the use of innovative technology to deliver high quality customer service and reduce customers' energy use and carbon footprint.

III. VISION AND CORE VALUES

9. Q. Please state the overarching vision that expresses what Exelon stands for as an organization.

A. At Exelon, we believe that reliable, clean and affordable energy is essential to a brighter, more sustainable future. That is why we are committed to providing innovative, best-in-class performance and thought leadership to help drive progress for customers, communities and our nation. Exelon believes in performance that drives progress.

10. Q. What are the core strengths of Exelon as an organization that support its vision?

A. Exelon has established five "pillars" that reflect its core strengths, support its vision, and are designed to translate that vision into a clear path for action:

1. **Performance Excellence**. We are committed to excellence and continuous improvement. We strive to be the best in everything we do.

2. **A Balanced Perspective**. Because we have a presence in each stage of the energy business, we have unique insights into the energy challenges we face today and will face in the future.

3. **Effective Collaboration**. We build strong working partnerships. We know that it is only through teamwork that we can develop and deliver smarter, cleaner, more efficient energy solutions.

4. **Driving Competition And Choice**. We believe that competition drives choice, innovation and savings and, in that way, empowers our customers and moves our nation forward.

5. **Advancing Clean Energy**. We are committed to connecting customers to cleaner, more cost-effective energy resources and to taking a leadership role in the process of shaping the future of clean energy.

11. Q. Please describe the core values that guide Exelon's decision making and behavior.

A. Exelon has five core values that cut across its organization and inform every aspect of its decision-making and behavior:

1. **We are dedicated to safety**. We are committed to maintaining the highest standards of safety and reliability for our people, our customers and the communities in which we work. As a fundamental part of our culture and operations, every member of the Exelon team is dedicated to putting safety first.

2. **We actively pursue excellence**. We are driven to excel. Recognizing the value of constant improvement, we strive to advance our processes and develop more efficient ways to meet our customers' energy needs. In all we do, we strive to surpass the standards of our industry and the standards we set for ourselves in order to create value for customers, communities and our shareholders.

3. **We innovate to better serve our customers**. We see every challenge as an opportunity to exercise our ingenuity and our competitive spirit. We encourage curiosity and exploration to develop better ways of delivering clean energy. We focus on innovation with the goal of creating energy solutions that have a meaningful, positive impact on our customers.

4. **We act with integrity and are accountable to our communities and the environment**. We are committed to doing what is right. We have a deep connection to the communities we serve, which compels us to take responsibility for our work. We actively look for ways to engage and give back. We value the environment and work to reduce our impact with future generations in mind.

5. **We succeed as an inclusive and diverse team.** We foster an inclusive culture of trust, collaboration and performance. We welcome and respect people with different perspectives, backgrounds, and traits because we know that diverse teams drive powerful outcomes.

12. Q. Mr. Crane, please explain how Exelon's core values relate to the commitments being made in connection with the Merger.

A. As I explained above, Exelon is dedicated to acting with integrity and accountability. That means we keep our promises and honor our commitments. Exelon has made regulatory commitments in connection with the mergers of Unicom and PECO that created Exelon in 2000 and Exelon and Constellation in 2012. Exelon has kept all the regulatory commitments that it made in connection with those transactions.

13. Q. Have you reviewed the statement of PHI's vision and core values set forth in Mr. Rigby's direct testimony?

A. Yes, I have. I concur with Mr. Rigby that, while Exelon and PHI each express their vision and values in their own, somewhat different words, the important substantive elements of our vision and core values are closely aligned.

14. Q. Why is it important to Exelon that it and PHI have substantially the same vision and core values?

A. The alignment of vision and core values is important on two levels. Following the effective date of the Merger, both Exelon and PHI will be working to integrate the Merger partners' operations and business processes. Functional integration will be facilitated if their operations and business processes are compatible. A common vision and shared values are strong evidence that our two companies' operations are generally consistent, which is an important reason that Exelon and PHI are excellent merger partners. A shared vision and common core values are also important because they express a common corporate culture. The cultural aspect of a business combination is one of the intangible factors that directly affects the successful longer-term operation of the enterprise. While there are many similarities in the corporate cultures of Exelon and PHI, I believe the common trait most important for forging a strong, post-Merger organization is the shared belief that we should never be content with "business as usual" in any aspect of our company and, therefore, we must continuously challenge ourselves to be better at everything we do, including, of course, managing and containing costs for the benefit of our customers, while providing safe, reliable service.

IV. REASONS FOR THE MERGER AND STRATEGIC FIT

15. Q. Mr. Crane, why did Exelon decide to merge with PHI?

A. Exelon has embarked on the Merger to create the premier Mid-Atlantic energy distribution utility and, as part of achieving that goal, to improve the overall customer experience in a meaningful way. The Merger furthers Exelon's strategic goals of increasing its focus on its core competency of operating best-in-class distribution utilities and diversifying its business. With the Merger, 60% to 65% of Exelon's pro forma earnings projected for 2015 and 2016 will be derived from its regulated distribution business.

16. Q. How will the Merger facilitate Exelon's goal of becoming the premier Mid-Atlantic energy distribution utility?

A. The Merger will join two companies that have an excellent strategic fit given their geographic location and other operational similarities. Together, they will form a post-Merger utility platform that possesses the scope, financial strength and operational expertise needed to adapt to the evolving role of distribution utilities. The wide-spread use of new and existing technology; the development, operation and management of an interactive grid; and the need to match load with a pool of widely distributed, customer-based resources demands the kind of large, geographically contiguous, interconnected system that the Merger will help to produce.

17. Q. Earlier you noted that Exelon and PHI are "an excellent strategic fit." Please explain why that is so.

A. The first significant factor is geography. Attached as JOINT APPLICANTS (A)-1 is a map showing the location of the PHI Utilities' service territories relative to those of BGE and PECO. Following the Merger, the Exelon family of utilities in the Mid-Atlantic region will have contiguous service territories stretching across southeastern Pennsylvania, southern New Jersey, Delaware, Maryland and the District of Columbia. Geographic proximity provides substantial opportunities to capture economies of scale and share best practices. Additionally, and perhaps most importantly, the geographic proximity of utilities within a single corporate family will give the post-Merger enterprise much more robust mutual support capabilities and substantially greater combined resources to respond promptly and effectively to major storms and other emergencies.

Additionally, in several important areas, the PHI and Exelon utilities have adopted similar programs, including advanced metering infrastructure ("AMI"), energy efficiency and demand response, and vendor/supplier diversity. Having these initiatives in common across the post-Merger enterprise will enable the sharing of knowledge and best practices, capture economies of scale and create opportunities to improve service and reduce costs. Moreover, these programs reflect a shared vision of the future in which the post-Merger Exelon utilities will continue to embrace innovative technology including through the use of the grid as an evolving platform for energy services for our customers, will partner with our customers to prudently manage energy use, and will strengthen their organization and the communities they serve by fostering a culture of diversity and inclusiveness.

V. BENEFITS THE MERGER WILL PRODUCE

18. Q. Please provide an overview of the benefits that the Merger will produce.

A. The Merger will create benefits for Pepco and the other PHI Utilities, their customers and the communities and states which they serve. First, it will create a strong foundation for meeting the challenges created by the evolving role of distribution utilities as the developers, operators and managers of an interactive grid that works as a platform to integrate renewable and distributed energy resources and accommodates customers' dual function as end users and producers of electricity. Second, the Merger will generate distribution-related synergies at

PHI that Exelon is proposing to reflect as an immediate – and longer term – direct and traceable financial benefit to Pepco's District of Columbia customers. Third, the Merger will leverage Exelon's resources and expertise to sustain and enhance reliability for Pepco and the other PHI Utilities within Pepco's and PHI's reliability related capital and O&M budgets. Fourth, PHI's charitable contributions and community support will be embodied in a firm commitment to maintain spending for ten years following the Merger in each of the PHI Utilities' service areas, including the District of Columbia, that, on average, exceeds 2013 levels.

Additionally, Exelon is proposing to take several important steps to protect customers and employees and to maintain the local presence of Pepco in the District of Columbia as well as the other PHI Utilities in their respective jurisdictions. I will discuss this issue later in my testimony.

19. Q. Please explain how customers of the PHI Utilities, including District of Columbia customers, will benefit from the distribution system synergies the Merger is expected to produce.

A. Distribution customers of all classes will realize an immediate direct and traceable financial benefit from the savings the Merger is expected to produce for Pepco and the other PHI Utilities by the creation of a $100 million Customer Investment Fund, of which $14 million will be allocated to Pepco operations in the District of Columbia. Exelon will fund this benefit, and the PHI Utilities will not seek to recover in rates any part of that fund. The Customer Investment Fund represents a direct and traceable benefit of more than $50 per District of

Columbia distribution customer. The disposition of each jurisdiction's share of that fund will be determined by the applicable regulatory authority in each jurisdiction following the consummation of the Merger. A regulatory authority could decide to use its share of the Customer Investment Fund to provide a bill credit to customers, to support low-income customer assistance programs or to strengthen energy-efficiency measures, although these are just examples and a regulatory authority could combine these and other or additional customer-benefit uses as it sees fit. Additionally, Exelon is making commitments to maintain and promote the PHI Utilities' low-income customer assistance, energy-efficiency and demand response programs, and those commitments are separate and apart from the commitment to create and fund the Customer Investment Fund.

20. Q. Is the Customer Investment Fund the only way in which Pepco customers will realize benefits from distribution-related Merger synergies?

A. No, it is not. District of Columbia customers will realize additional direct and traceable financial benefits as transmission-related and distribution-related Merger synergies are fully recognized in future rate proceedings in the form of costs that are lower than they would have been absent the Merger. The Merger integration process and the distribution-related savings it is expected to produce are addressed in greater detail by Mr. Khouzami.

21. Q. Please explain how the reliability-related benefits of the Merger will be produced.

A. As I previously noted, the Merger will leverage Exelon's resources and expertise to enhance reliability for Pepco and the other PHI Utilities without increasing Pepco's reliability-related capital and O&M budgets. It is important to acknowledge the significant improvement in reliability that the PHI Utilities, including Pepco, have accomplished, which Exelon plans to build upon. Similarly, Exelon acknowledges the regulatory performance requirements that are already in place for Pepco and the other PHI Utilities. Exelon intends not only to achieve compliance with the current regulatory performance requirements, but also to make further improvements in reliability metrics. Exelon is also proposing to back-up its commitment with a performance guaranty that will trigger a financial penalty if our performance-improvement goal is not achieved. Exelon's performance guaranty, its reliability-related capabilities, and the track record of top-tier operational performance by its utilities are discussed in more detail in Mr. Alden's direct testimony. The details of the proposed financial penalty are discussed in Mr. Khouzami's direct testimony.

22. Q. How will Exelon ensure that its efforts to enhance reliability will be cost-effective?

A. Exelon understands that expenditures for reliability can reach a point of diminishing returns at which the level of investment, or increase in maintenance expense, may not be justified by the incremental improvements in reliability they produce. Exelon has no intention of trying to achieve improvements in reliability simply by spending more. We don't do business that way. As I explained before, an integral part of our management model is to continuously challenge ourselves to be more efficient and more productive – to always strive to do things better and at a lower cost. We have demonstrated that this approach works in improving system reliability. The most recent example is the performance of BGE following Constellation's merger with Exelon. At BGE, we made significant improvements in reliability metrics without increasing BGE's reliability-related capital or O&M budgets, as Mr. Alden discusses in his direct testimony. We plan to do the same for the PHI Utilities. The reliability performance improvements we propose for Pepco and the other PHI Utilities will be accomplished without increasing Pepco's or the other PHI Utilities's reliability-related capital or O&M budgets in their existing long-range plans.

Exelon's hard work to control costs does not mean it intends to scrimp on needed capital improvements. In fact, BGE, ComEd and PECO have approved plans to spend $15 billion in aggregate over five years for capital improvements to their systems. To state it simply, if capital investment is needed, the necessary resources will be provided.

23. Q. The District of Columbia and the other service areas of the PHI Utilities, like those of PECO and BGE, have experienced several severe weather events over the past several years. Please describe Exelon's emergency response performance and explain how the Merger will enhance emergency response capability of Pepco and the other PHI Utilities.

A. PECO and, following the Constellation merger, BGE, have performed well in responding to major storm events, as Mr. Alden explains. In large part, this performance was made possible by the ability of the utilities in the Exelon system to marshal their forces from across the enterprise to provide prompt and effective storm restoration. Those benefits will be extended to Pepco in order to support and enhance its emergency response efforts in the District of Columbia following the Merger. Additionally, as I previously explained, the geographic proximity of the PHI Utilities to BGE and PECO will enhance mutual support capabilities for all of Exelon's Mid-Atlantic utility systems and create a much larger pool of combined resources to respond quickly and effectively to major storm events or other emergencies.

24. Q. Is there anything else you would like to add on the issue of reliability?

A. Yes, I want to make it clear that Exelon takes reliability very seriously. We understand the importance of keeping the lights on throughout the areas we serve. We also acknowledge the special responsibility – and the corresponding honor and privilege – of serving as the electricity supplier for our nation's capital. We understand that Washington, D.C. is the image we project to the world and the showcase for our country's energy policy. We will work tirelessly to make sure that Pepco continues to provide Washington, D.C. the world class electric service that it expects and deserves from its electric utility.

25. Q. Please explain how the Merger will strengthen PHI's charitable contributions and community support.

A. The Merger will strengthen PHI's charitable and community involvement by converting what are now voluntary contributions into a binding commitment. As explained in the direct testimony of Calvin G. Butler, Jr., Exelon is committing to provide for ten years following the Merger an annual average in charitable contributions and traditional local community support that exceeds the 2013 levels of the PHI Utilities. Additionally, as part of Exelon, the PHI Utilities will continue to play an important role in supporting the communities in their service areas and will remain a significant employer and responsible corporate citizen, as evidenced by the commitments to community service made by the Exelon companies and their employees and the civic and charitable activities of BGE following the Constellation merger, as Mr. Butler also describes.

26. Q. Mr. Crane, did Exelon and PHI consider how the District of Columbia and the states in which the PHI Utilities operate will be affected by the Merger?

A. Yes. Exelon and PHI retained Susan F. Tierney, Ph.D., to study the economic effects of the Merger upon the District of Columbia and the three states in which the PHI Utilities furnish service. Dr. Tierney conducted a detailed study using well-recognized and widely-accepted analytic techniques to quantify the effects of the Merger in those locations, including the effects of an increase in reliability at each of the PHI Utilities from their current three-year average performance levels to the reliability levels described by Mr. Alden. The value of the benefits accruing to Pepco's residential and commercial customers and to the District of Columbia from reduced outages with shorter duration, together with the portion of the Customer Investment Fund to be distributed to Pepco customers, is expected to be within a range of $95.4 million to $133.6 million over the period 2015 to 2020 on a net present value basis. In addition – depending upon how the District of Columbia Public Service Commission (the "Commission") decides to allocate the Customer Investment Fund – the expected benefits from the Merger will include the creation of between 907 and 1,281 jobs in the District of Columbia.

I know the Commission recognizes the value of reliability. In my view, the Merger is a crucial step to ensure that District of Columbia and the customers of Pepco can realize the significant benefits described by Dr. Tierney. Upon completion, the Merger will create a real partnership to achieve a level of utility service reliability that not only meets the future requirements that the PHI Utilities have today but exceeds those requirements. This partnership will be backed by Exelon's commitment to share best practices with the PHI Utilities to increase reliability within the reliability-related capital and O&M budgets that the PHI Utilities have already planned, and financial penalties if we fail to achieve what we are promising to do.

27. Q. Earlier, you indicated that Exelon proposes to take additional steps to protect customers. Please discuss those measures.

A. While PHI has non-regulated businesses that are operated as part of Pepco Energy Services, it is predominantly a "pipes and wires" distribution utility company. With the Merger PHI will be joining a company that has a generation component, including substantial nuclear generation, which some may contend could expose Pepco and the other PHI Utilities to a qualitatively different array of business risks. I believe that perception is not warranted. Exelon is a leader in nuclear safety and has been recognized for the world-class performance of its nuclear generating facilities. Moreover, Exelon has the expertise, experience and broadly diversified exposure to multiple energy markets to effectively mitigate market risks in its generation business. Nonetheless, in order to put this issue to rest, Exelon proposes to implement ring-fencing measures designed to isolate

Pepco and the other PHI Utilities from the potential financial and credit consequences of unrelated business risks, including financial risks that could arise from Exelon's nuclear operations. The specific ring-fencing measures that will be implemented and their effectiveness in insulating Pepco and the other PHI Utilities are discussed in greater detail in Mr. Khouzami's direct testimony.

28. Q. Please describe the protections Exelon is offering for Pepco employees and the employees of the other PHI Utilities.

A. I fully concur with Mr. Rigby's statement that the strength of any business lies in its people. That is why Exelon prides itself on treating its employees fairly. The Merger will result in some reductions in force. For example, certain positions in the managerial and administrative ranks will no longer be necessary as duplicative positions are consolidated. However, Exelon has committed that for a period of two years after consummation of the Merger, there will be no net reductions due to involuntary attrition as a result of the Merger integration process in the employment levels of the PHI Utilities. In that regard, Exelon has clearly stated it will honor all existing collective bargaining agreements. Moreover, as Mr. Rigby explains in his direct testimony, Locals 210, 1238, 1307 and 1900 of the International Brotherhood of Electrical Workers, which comprise all of the collective bargaining units that represent employees of PHI Utilities, agree the Merger is in the best interest of Pepco and its employees and have recently agreed to contract extensions for an additional three years. Also consistent with the Merger Agreement, Exelon has agreed that for at least two years after closing the Merger, Exelon will provide current and former PHI Utilities' employees compensation and benefits that are at least as favorable in the aggregate than the compensation and benefits provided to those employees immediately before the Merger. These commitments are discussed by Denis P. O'Brien in his direct testimony.

Additionally, Exelon will ensure that, after the Merger, PHI and the PHI Utilities, including Pepco, will continue their commitments to workforce diversity. Exelon believes it is critical that its workforce reflect the diversity of the communities it serves because diverse teams drive powerful and successful outcomes. For that reason, diversity and inclusiveness are key elements of Exelon's core values, as I explained in Section III of my testimony. Moreover, Exelon has received national and local recognition for its dedication to diversity and inclusiveness.

29. Q. How will the Merger affect the local presence and local control of PHI and Pepco?

A. Currently, PHI is a publicly traded holding company that owns the stock of the PHI Utilities. Following the Merger, PHI will no longer have a publicly traded common stock and, as a consequence, a number of corporate functions associated with public common-stock ownership will no longer be performed at the PHI level. However, based on the explanation of the PHI operating structure provided by Mr. Rigby, it is anticipated that PHI will continue to play much the same role in the day-to-day operations of the Pepco and the other PHI Utilities that it does today, and the existing operational structure of PHI will remain substantially the same. PHI and Pepco will continue to maintain their headquarters in Washington, D.C. Additional details about the post-Merger operational and management structure and the importance of maintaining local control and local presence are provided in the direct testimony of Mr. O'Brien. Mr. Butler's direct testimony details the BGE experience where Exelon has maintained local control and a local presence after its merger with Constellation.

30. Q. How will the Merger affect the access and accountability of management?

A. The Merger will not affect access to and the accountability of management. Regulators, government officials, community leaders and customers will know the people working at the utility level. Moreover, both Mr. O'Brien, who leads Exelon Utilities, and I are committing to being accessible and accountable to regulators, state and local governments, and all of the utilities' other constituencies. In that regard, as Mr. O'Brien explains in his direct testimony, Exelon has a straightforward utility management model with clear, direct lines of authority and reporting. Thus, Exelon's utility management model allows the operating utilities, which, post-Merger, will include PHI as the operating arm of the PHI Utilities, to access the resources, expertise and financial strength of a large organization while maintaining the ability to respond to local conditions and priorities. Simply stated, the Merger will not create multiple tiers of management that have to be penetrated to access the decision-makers in the organization.

31. Q. Mr. Crane, in light of the importance Exelon places on reducing carbon emissions through renewable technology and other means, please explain

Exelon's experience in carbon reduction and expansion of renewable energy sources.

A. Under Exelon's 2020 Plan, each Exelon utility took a variety of additional actions to reduce its own carbon footprint, such as minimizing internal building electricity use through aggressive building modernization, using clean technologies and alternative fuels in fleet vehicles and delivering customer energy efficiency savings through PECO's and ComEd's award winning "Smart Ideas" programs. Through these combined efforts, Exelon met – indeed, surpassed – the ambitious target of reducing its carbon footprint by 17.5 million metric tons of greenhouse gas emissions and did so in 2013 – thus achieving the goal and completing the mission of Exelon 2020 seven years ahead of its planned completion date.

Exelon is an industry leader in adopting renewable energy technology, as evidenced by the nearly 1,300 megawatts ("MW") of wind generation and approximately 240 MW of utility-scale and distributed solar generation owned and operated by its generation companies. Similarly Exelon's retail companies have installed more than 173 MW in distributed generation for customers and supplied renewable electricity to more than 82,300 customers. The post-Merger organization will consolidate the intellectual capital, technical expertise and experience of a deeper and more diverse workforce that has developed skill sets vital to implementing renewable energy solutions and energy savings programs.

32. Q. Have the Exelon utilities received special recognition for their environmental stewardship?

A. Yes, they have. Each of the Exelon utilities was recognized in 2012 and 2013 as a United States Environmental Protection Agency Energy Star award winner for Sustained Excellence for continued leadership in protecting the environment through its energy efficiency efforts. Additionally, on June 11, 2014, Exelon was recognized for its corporate sustainability and environmental performance by ranking second among utilities in the 2014 *Newsweek* Green Rankings.

33. Q. Mr. Crane, will the public interest be served by completing the Merger?

A. Yes. The Merger definitely will benefit the public, rather than merely leave it unharmed, for all of the reasons that I set forth above, which are explained in more detail in the Joint Application and the direct testimony of other witnesses supporting the Merger.

34. Q. In your discussion of the benefits the Merger will produce, you referred to commitments that Exelon and the PHI Utilities are making in connection with the Merger. Is Exelon providing a complete list of those commitments?

A. Yes, all of the commitments being proposed by Exelon and the PHI Utilities are set forth in Exhibit 5 to the Joint Application.

VI. INTRODUCTION OF OTHER WITNESSES

35. Q. Please identify the other witnesses that have submitted direct testimony in support of the Merger.

A. The witnesses that submitted direct testimony with the Joint Application are listed below along with a general description of the subject matter of their direct testimony:

Joseph M. Rigby is the Chairman of the Board, President and Chief Executive Officer of PHI. Mr. Rigby provides PHI's perspective on the Merger, describes the vision and values of PHI and explains why the Merger is in the best interests of the PHI Utilities, their customers and the communities they serve. (JOINT APPLICANTS (B))

Denis P. O'Brien is Senior Executive Vice President of Exelon and Chief Executive Officer of Exelon Utilities. Mr. O'Brien describes how the PHI Utilities will be managed following the Merger, including how the operational structure, governance principles and delegation of authority will maintain substantial local control. Mr. O'Brien also discusses the experience of integrating utility operations following the merger of PECO and Unicom and the merger of Exelon and Constellation, which brought BGE into the Exelon family of utility companies. Finally, Mr. O'Brien describes Exelon's commitments regarding employment levels and employee compensation. (JOINT APPLICANTS (C))

Mark F. Alden is the Vice President of Utility Oversight and Integration for Exelon. Mr. Alden explains Exelon's commitments to enhance reliability across the PHI Utilities' service area and discusses Exelon's track record of reliability and high-quality service. He also identifies some of the more significant technological solutions that can be employed to cost-effectively strengthen reliability across the PHI Utilities' service area following the Merger. (JOINT APPLICANTS (D))

William M. Gausman is Senior Vice President, Strategic Initiatives, of PHI. Mr. Gausman describes the regulatory requirements for reliability that currently apply to Pepco and the commitments that it has made with regard to achieving specified reliability performance goals. (JOINT APPLICANTS (E))

Carim V. Khouzami, a Senior Vice President of BGE, is Exelon's Chief Integration Officer. Until recently assuming the position of Chief Integration Officer, he served as BGE's Chief Financial Officer and Treasurer. Mr. Khouzami provides an overview of the planned integration of Exelon and PHI, explains the process for identifying merger savings and costs to achieve those savings, and discusses the cost-reducing synergies that were achieved through the successful integration of BGE following the Exelon-Constellation merger. Additionally, Mr. Khouzami discusses the financial impacts of the Merger, merger accounting principles, the measures Exelon will implement to ring-fence the PHI Utilities and the financial penalty Exelon is proposing in the event that Pepco fails to meet Exelon's reliability commitment. (JOINT APPLICANTS (F))

Susan F. Tierney, Ph.D. is a Senior Advisor with the Analysis Group. Dr. Tierney discusses the quantitative and qualitative economic benefits that the proposed Merger brings to the District of Columbia and to the customers of Pepco in that jurisdiction. (JOINT APPLICANTS (G))

Calvin G. Butler, Jr. is BGE's Chief Executive Officer. Mr. Butler describes Exelon's approaches to electric system reliability, charitable giving, community involvement, and supplier diversity. He also provides relevant background information about Exelon's existing programs in each of these areas. (JOINT APPLICANTS (H))

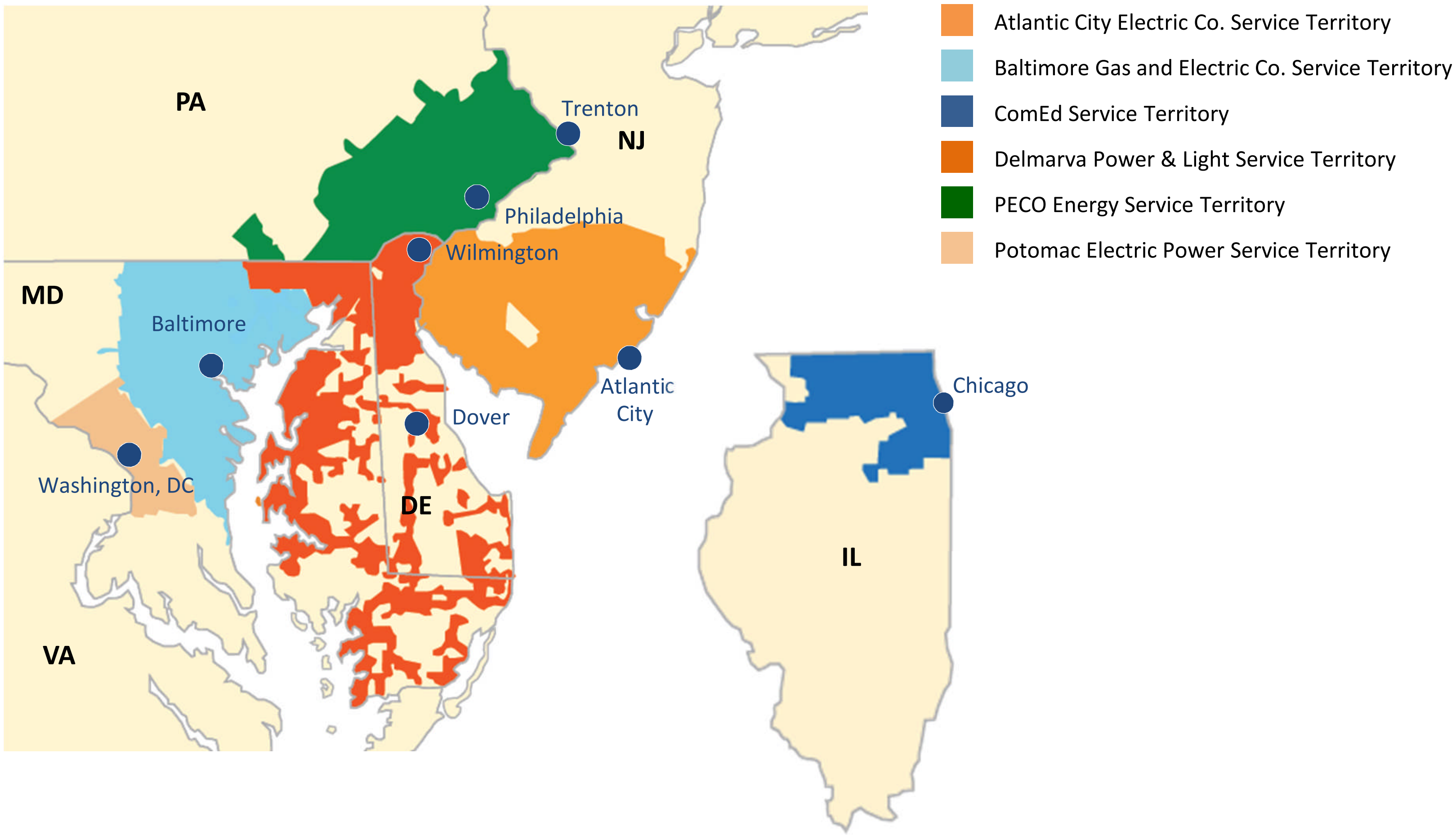
VII. CONCLUSION

36. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

C.M. Crane Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _____ (A)-1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Baltimore Gas and Electric Co. Service Territory
ComEd Service Territory
Delmarva Power & Light Service Territory
PECO Energy Service Territory
Potomac Electric Power Service Territory
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VA
IL
Trenton
Philadelphia
Wilmington
Baltimore
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J.M. RIGBY Direct Testimony
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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF JOSEPH M. RIGBY

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is Joseph M. Rigby. My business address is 701 9th Street, NW, Washington, DC 20068.

2. Q. By whom are you employed and in what capacity?

A. I am the Chairman of the Board of Directors, President and Chief Executive Officer of Pepco Holdings, Inc. ("PHI"). PHI is the parent of Potomac Electric Power Company ("Pepco"), which provides electric delivery service in Washington, D.C., and Montgomery and Prince George's Counties in Maryland. PHI is also the parent of Delmarva Power & Light Company ("Delmarva Power"), an electric and gas utility serving Delaware and portions of the Delmarva Peninsula, and Atlantic City Electric Company ("ACE"), an electric utility serving southern New Jersey. I will refer to Pepco, Delmarva Power and ACE collectively as the "PHI Utilities."

3. Q. Please describe your professional and educational background.

A. I joined ACE in 1979 and advanced through a number of management positions. My responsibilities have included accounting, financial services, treasury operations, business transformation, human resources, and the ACE/Delmarva Power merger transition. Upon the merger of ACE and Delmarva Power that formed Conectiv, I became Vice President/General Manager of Gas

Delivery, then Vice President/General Manager of Electric Delivery for those utilities. I was elevated to President of Conectiv Power Delivery in 2002. From May 2004 to September 2007, I served as Senior Vice President and Chief Financial Officer of PHI and was responsible for all financial activity and investor relations.

From September 2007 to March 2008, I served as Executive Vice President and Chief Operating Officer of PHI. In that capacity, I was responsible for the day-to-day operations of Pepco, Delmarva Power and ACE and was also responsible for those companies' information technology and corporate communication functions. In March 2008, I was elected President and Chief Operating Officer of PHI.

I was elected President and Chief Executive Officer of PHI effective March 1, 2009, and was elected Chairman of the Board on May 15, 2009.

I earned a bachelor's degree in accounting from Rutgers University and an MBA from Monmouth University. I am a licensed Certified Public Accountant ("CPA") in the state of New Jersey.

4. Q. Please identify relevant business or professional associations.

A. I am the immediate past chair of the United Way of the National Capital Area. I am currently a member of the senior council of the Greater Washington Board of Trade and previously served as the chairman of that organization. I also serve on the boards of the U.S. Chamber of Commerce, the Edison Electric Institute, the Federal City Council, the Greater Washington Initiative, and the Economic Club of Washington. I am a member of the Rutgers-Camden School of

Business Executive Advisory Board, the New Jersey Society of CPAs and the American Institute of CPAs.

5. Q. What is the purpose of your direct testimony?

A. I will provide PHI's perspective on the proposed merger ("Merger") of PHI and Exelon Corporation ("Exelon"), which was announced on April 30, 2014. In particular I will discuss the values and vision that PHI and Exelon share, describe the current PHI management structure and explain why I believe that the Merger is in the best interest of the PHI Utilities, their customers and the communities they serve and, therefore, is in the public interest.

II. VALUES, VISION AND MANAGEMENT STRUCTURE

6. Q. Please describe the core values of PHI.

A. PHI organizes all aspects of its business around the following five core values:

1. **Safety –** We make safety the most important part of everything we do.
2. **Accountability –** We accept responsibility for our actions and behavior.
3. **Integrity –** We do the right thing.
4. **Diversity –** We treat everyone with dignity and respect.
5. **Excellence –** We strive to be the best.

7. Q. Please describe PHI's overarching vision for its utility operations.

A. PHI's vision is expressed in the following comprehensive statement:

> We aspire to become the best in class in safety, reliability, customer service and innovation by engaging our talented workforce, leveraging operational excellence and applying advanced technology. We seek to empower our customers through a smarter grid, create energy solutions for our

> business partners, protect our environment and deliver value to our shareholders.

Let me expand briefly on the principal elements of that statement. By "best in class," we mean outperforming our peers while meeting the needs of customers. "Innovation" refers to our focus on leveraging expertise in order to optimize energy resources and energy use by our customers and business partners. We strive to achieve the goal of "engaging our talented workforce" by building high-performing teams through leadership, teamwork, enterprise focus, accountability and communication. The second sentence of our aspiration statement expresses our emphasis on operational excellence and the need to face the challenges of the future by working to achieve creative energy solutions that continue to reliably deliver a vital service to our customers while reducing energy costs and protecting the environment.

8. Q. How do PHI's vision and core values compare with those of Exelon, which are summarized in Mr. Crane's direct testimony?

A. While each company expresses concepts in its own words, the substance of the visions and core values of PHI and Exelon are closely aligned.

9. Q. Why is it significant to the success of the Merger that PHI and Exelon share a common vision and core values?

A. Having a common vision and sharing core values will facilitate the alignment of various business processes and the integration of the operations of the PHI and Exelon utilities following the Merger. This is an important reason why PHI and Exelon are excellent merger partners. Proper alignment of business processes will simplify and expedite the integration process and, in that way, help the post-Merger enterprise achieve fully and in a shorter time the performance improvements and cost savings expected from the Merger.

10. Q. Please describe the priorities of PHI for 2014 with respect to providing utility service.

A. Consistent with the vision and values I discussed previously, PHI has established the following priorities for power delivery operation:

1. **Safety –** Everyone goes home safely every day.
2. **Reliability –** We seek to improve our customers' experience by reducing power outages and improving communications during restorations.
3. **Customer Satisfaction –** We seek to improve the customer experience through a comprehensive process management and technology approach, and we work together to make PHI a better, more challenging and rewarding place to work.
4. **Regulatory Compliance –** We meet our regulatory and compliance commitments.
5. **Financial Results –** We meet our financial commitments.

Joining Exelon's top-performing family of utilities will provide additional resources to allow PHI's operating subsidiaries, including Pepco, to enhance their ability to achieve the priorities listed above and likely accelerate the achievement of those priorities in an efficient and cost-effective manner.

11. Q. Please describe the PHI management structure.

A. Pepco, along with its affiliates ACE and Delmarva Power, are separate corporations, although their financial results are reported as a single business segment of PHI for Securities and Exchange Commission reporting purposes. The three PHI Utilities provide service in four jurisdictions because Pepco furnishes service in the District of Columbia and Maryland, Delmarva Power furnishes service in Delaware and Maryland and ACE furnishes service in New Jersey. The utilities are operated under the supervision of the Executive Vice President, Power Delivery of PHI. Each utility has a complement of its own employees that provides certain engineering and customer service functions, operational support, and maintenance of the transmission and distribution system for that utility. In addition, personnel employed by the PHI Service Company, such as substation engineers and designers, perform utility-specific work for one or more of the utilities. Corporate and administrative support functions, such as accounting, legal and regulatory, generally are performed by employees of the PHI Service Company because those employees typically provide similar services to more than one utility company.

Each utility also has a Regional President that reports to the Senior Vice President, Government Affairs and Public Policy of PHI. The individual Regional Presidents work closely with the operational side of the business, provide a strong local connection in each jurisdiction and maintain relationships with government and regulatory officials and other stakeholders in the communities we serve.

Our management structure enables cost efficiencies across the jurisdictions by sharing services where appropriate while also maintaining a local presence in each of our jurisdictions. As explained in Mr. O'Brien's direct testimony this general management structure, including a focus on Pepco's local presence and control, will be maintained following the Merger.

III. THE MERGER IS IN THE BEST INTEREST OF THE PHI UTILITIES, THEIR CUSTOMERS AND THE COMMUNITIES THEY SERVE

12. Q. Please provide an overall assessment of the Merger from your perspective.

A. I am convinced that the Merger will create a strong, well-managed, financially stable family of transmission and distribution utilities that are committed to providing high-quality service at reasonable cost. During my tenure as CEO, the PHI Utilities have been placed on a path of continuous improvement in reliability and customer satisfaction. As Mr. Gausman describes in his direct testimony, Pepco has an extensive set of multi-year programs designed to meet its reliability commitments and, as a result, has made significant progress in its reliability performance Pepco is currently exceeding the District of Columbia's reliability requirements.

Pepco strives to continue the progress it has made in these areas and, in so doing, to fully meet and, indeed, exceed, our customers' expectations. There is no question in my mind that joining Exelon's outstanding distribution utilities will help us to do that by providing significant additional resources to sustain and improve current levels of performance and customer satisfaction. My assessment of the Merger's benefits is backed by the package of explicit and substantial commitments that Exelon is offering in connection with the Merger. It is also backed by the well-established track record of reliable service, sensitivity to local priorities and concerns, cost-consciousness, environmental stewardship and outstanding corporate citizenship that Exelon has established.

On a personal level, throughout the Merger process I have spent a good deal of time with, and come to know, the senior management at Exelon and Exelon Utilities. As a result, I have had an excellent opportunity to learn and understand their approach to Merger integration and, more importantly, their approach to the on-going management and operation of distribution utilities within their corporate family. I am confident that the post-Merger organization will continue to be managed by a team of skilled professionals who are customer-focused and committed to the sustainable, long-term performance of Pepco at the highest levels. I am certain that, upon my retirement, which I have now deferred until the Merger is consummated, I will be leaving the Pepco in good hands. I firmly believe that Exelon will maintain high-quality service, meet customers' needs reliably and efficiently, respect all of the constituencies we serve and actively engage in the civic and charitable life of our service areas.

13. Q. Why are PHI and Exelon well suited as merger partners?

A. There are three principal reasons why PHI and Exelon are well suited as merger partners. First, as I explained earlier, they share a common vision and core values. The two organizations' visions of the future and their approach to delivering safe, reliable and efficient service are closely aligned. I believe these factors will promote a smooth transition throughout the Merger integration process and, as a result, allow the companies to achieve a higher level of sustainable merger savings.

Second, the PHI and Exelon utilities share a number of factors that are critical to their structural and operational integration. These factors are described in Section IV of Mr. Crane's direct testimony, and I will not repeat them here. However, I want to emphasize the importance of geographic proximity. The service territory map that Mr. Crane is providing as JOINT APPLICANTS (A)-1 tells this story graphically. Geographic proximity will facilitate coordinated management across the combined utility service territories in the Mid-Atlantic Region and will maximize the opportunities to capture economies of scale. However, in my view, the principal benefit from the close geographic fit of the PHI Utilities', BGE and PECO service areas is the strong mutual support structure it will create. This mutual support structure will enhance performance and lower costs. The most significant beneficial impact of enhanced mutual support will be derived from the ability to marshal the greater combined resources of contiguous utilities within the same corporate organization to respond to major storms or other emergency situations and reduce recovery time.

Third, the PHI operational goals that I identified in Section II closely align with initiatives that have been adopted and are being implemented among the Exelon utilities. Thus, the combined enterprise will be on the same page in terms of deploying resources and management attention to drive the performance of their utilities. To cite just one important example, the Exelon utilities, like Pepco, are implementing Smart Grid and advanced metering infrastructure ("AMI") solutions and planning to use that technology to reduce costs, improve service, expedite emergency response, and provide customers more options for managing their energy needs.

14. Q. Is the proposed Merger in the best interest of Pepco and its customers?

A. Yes, it is, for the reasons I discussed in some detail above. In summary, the Merger will enable the PHI and Exelon utilities to leverage each other's expertise through effective sharing of best practices. The Merger will also strengthen the Pepco's emergency response capabilities by providing access to greater resources available from a larger enterprise and provide financial resources that assure sustainable, long-term operational excellence. All of these factors generate significant benefits for District of Columbia customers. Moreover, Exelon is proposing firm reliability guarantees, which would trigger financial penalties if performance-improvement goals are not achieved. Significantly, as Mr. Crane explains, Exelon anticipates that Pepco will meet its heightened performance goals without increasing existing reliability-related capital and operating and maintenance budgets. Exelon also is committed to the District of Columbia undergrounding project, which will provide significant benefits to District of Columbia customers.

Additionally, Pepco customers in the District of Columbia will realize an immediate tangible benefit of more than $50 per distribution customer from the Exelon-funded Customer Investment Fund that will be established to allow customers to realize Merger-related savings. At the same time, Exelon is committing to flow-through all actual test-year distribution-related Merger savings, net of costs to achieve, in future rate cases. Exelon is also making an explicit commitment to maintain the PHI Utilities' low-income customer assistance, energy efficiency and demand response programs.

15. Q. Are there any other factors that are important to you?

A. Yes. I believe that the strength of any business lies in its people. Consequently, we cannot think about delivering safe, reliable and efficient utility service without considering our employees. Exelon shares my view. In that regard, Exelon has clearly stated it will honor all existing collective bargaining agreements, and I am pleased to report that all of the collective bargaining units that represent our employees, namely, Locals 210, 1238, 1307 and 1900 of the International Brotherhood of Electrical Workers, agree the Merger is in the best interest of Pepco and its employees and have recently agreed to contract extensions for an additional three years. Additionally, Exelon is making specific commitments that for two years following the Merger there will be no net reduction due to involuntary attrition as a result of the Merger integration process in the employment level at Pepco and that there will be provided to current and former employees of Pepco compensation and benefits that are at least as favorable, in the aggregate, as the compensation and benefits provided to those employees immediately before the Merger. These commitments are explained in the direct testimony of Denis P. O'Brien.

16. Q. Why is the Merger in the best interest of the District of Columbia?

A. The Merger will maintain the local presence of Pepco, as evidenced by specific commitments in this regard made by Exelon and discussed by Mr.

O'Brien. Additionally, as Mr. O'Brien explains, Pepco and the other PHI Utilities will continue to be operated in largely the same manner as they are today. Regulators, government officials, community leaders and customers will continue to know the people who are working at the utility level to keep their lights on. Clear lines of communication will continue to be in place. As Mr. Crane emphasizes in his direct testimony, Exelon is just as committed as Pepco and PHI are to being accessible to regulators, state and local governments, businesses, and civic and charitable organizations.

The District of Columbia will also benefit from Exelon's express commitment to provide, for ten years following the Merger, an annual average in charitable contributions and traditional local community support that exceed 2013 levels.

Finally, the District of Columbia will realize substantial tangible benefits from the Merger, which have been identified and quantified by Susan F. Tierney, Ph.D. in her direct testimony and accompanying analysis.

17. Q. Is the Merger in the public interest?

A. Yes, it is, for the reasons I discussed previously. In summary, PHI and its utility subsidiaries will be better positioned to meet the challenges of furnishing safe, reliable and efficient service currently and in the future with the added resources they will gain from joining the Exelon family of utilities. The Merger, along with the Merger-related commitments being made by Exelon, will provide immediate and long-term tangible benefits to customers, the communities the PHI Utilities serve and the District of Columbia. I have no reservations in recommending that the Merger be approved. Indeed, the sooner the Merger can be consummated the sooner District of Columbia customers and the District of Columbia itself will begin to realize the substantial benefits that the Merger will produce.

IV. CONCLUSION

18. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

D.P. O'BRIEN Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants ___________(C)

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BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF DENIS P. O'BRIEN
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I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is Denis P. O'Brien. My business address is 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. By whom are you employed and in what capacity?

A. I am Senior Executive Vice President of Exelon Corporation ("Exelon") and Chief Executive Officer of Exelon Utilities ("EU"). In that capacity, I am responsible for the activities of Exelon's regulated transmission and distribution businesses, which serve approximately 7.8 million customers. EU is an unincorporated division of Exelon, which I will describe below.

3. Q. Please describe your educational and professional background.

A. I have a Bachelor's Degree in Industrial Engineering from Rutgers University and a Master's Degree in Business from Drexel University. I have over 30 years of utility experience in engineering and operations, strategic planning, and executive management.

I began my career in 1982 as an engineer in PECO Energy Company's ("PECO") Transmission and Distribution Department performing a variety of engineering, project management, and supervisory duties. In 1987, I was promoted to Division Engineer of the Philadelphia Division. From 1989 to 1991, I was assigned to the PECO Corporate Planning Department where I supported

PECO's implementation of Total Quality Management. From 1991 to 2000, I progressed through various supervisory and managerial positions in PECO's Operations Department.

In 2000, I was promoted to Vice President of Operations for PECO. In that capacity, I was responsible for the operation and maintenance of PECO's electric and gas transmission and distribution systems and the construction of additions and replacements to those systems. In 2002, I was appointed Executive Vice President and, in that capacity, was responsible for all of PECO's day-to-day operations. In 2003, I was promoted to President of PECO, and, in 2007, was named its CEO.

In March 2012, upon completion of the merger of Exelon and Constellation Energy Group, Inc. ("Constellation"), I assumed my current position with Exelon.

4. Q. Please identify your other business, professional and civic affiliations.

A. I am chairman of the board of directors of the Electric Power Research Institute ("EPRI") and serve on the board of directors of Independence Blue Cross. I am also chair-elect of the Greater Philadelphia Chamber of Commerce and a member of the boards of trustees of the Pennsylvania Business Council, the CEO Council for Growth, the Franklin Institute, and Drexel University. I previously served on the boards of the American Gas Association, the Energy Association of Pennsylvania, the Pennsylvania Economy League, the YMCA of Greater Philadelphia and WHYY, Inc.

5. Q. Have you previously testified before a utility regulatory agency?

A. Yes. I submitted direct, supplemental direct and rebuttal testimony before the Pennsylvania Public Utility Commission at Docket No. A-110550F0160, which was the proceeding for approval of the proposed merger of Exelon and Public Service Enterprise Group, Inc. ("PSEG"). I also submitted rebuttal testimony before the New Jersey Board of Public Utilities ("BPU") at BPU Docket No. EM05020106, which was the proceeding for BPU approval of the same transaction. The proposed merger of Exelon and PSEG was not consummated. In addition, I submitted rebuttal testimony before the Public Service Commission of Maryland on behalf of the applicants in Case No. 9271, which was the proceeding for approval of the merger of Exelon and Constellation.

6. Q. What is the purpose of your direct testimony?

A. My testimony supports the proposed merger ("Merger") of Exelon and Pepco Holdings, Inc. ("PHI"). As CEO of EU, upon consummation of the Merger, I will have a direct role in the management of Potomac Electric Power Company ("Pepco"), Atlantic City Electric Company ("ACE") and Delmarva Power & Light Company ("Delmarva Power") (collectively, the "PHI Utilities"). I will describe Exelon's approach to managing its electric and natural gas delivery utilities, including the role of EU and my role within EU. As part of that discussion, I will explain the role that PHI will play within the Exelon corporate and management structure after the Merger is consummated. I will also describe Exelon's commitment to maintaining substantial local control of utility operations, summarize the institutional measures that Exelon has in place for its existing utilities to define and preserve local control, and explain how those measures will be extended to PHI after the Merger is completed. Additionally, because sharing of best practices is critical to realizing the benefits expected from the Merger, I discuss my experience in the successful processes of sharing best practices following the merger of PECO and Unicom Corporation ("Unicom") to form Exelon and the merger of Exelon and Constellation, which added Baltimore Gas and Electric Company ("BGE") to the Exelon family of electric and gas distribution and transmission utilities. I will also describe the commitments Exelon and PHI are making with regard to post-Merger employment and compensation at ACE, Delmarva Power and Pepco. Finally, I will explain that the Merger will not affect standard offer/default service or local electricity competition in the District of Columbia nor will it affect wholesale competition or raise any market power concerns.

II. THE EXELON UTILITY MANAGEMENT STRUCTURE

7. Q. Please describe where PHI and the PHI Utilities will be located in the Exelon corporate structure post-Merger.

A. The pre-Merger and post-Merger corporate structures of PHI and Exelon are depicted in the organization charts provided as Exhibit 4 to the Joint Application. Consequently, I will provide only a brief overview of the relevant elements of the before and after corporate structures.

Exelon. All three of Exelon's utilities – BGE, Commonwealth Edison Company ("ComEd") and PECO – are subsidiaries of Exelon Energy Delivery Company, LLC ("EEDC"), which is a direct subsidiary of Exelon. EEDC is a holding company and has no employees. ComEd and PECO are direct subsidiaries of EEDC, while BGE is a subsidiary of RF Holdco, LLC ("RF Holdco"), which is, in turn, a subsidiary of EEDC. RF Holdco is a special purpose entity ("SPE") created to implement "ring-fencing" measures designed to insulate BGE from the risks the Commission perceived with Constellation's competitive businesses. There will be no change in the positions of Exelon's utilities, RF Holdco or EEDC within the Exelon corporate structure as a result of the Merger.

PHI. Currently, Pepco is a direct subsidiary of PHI. Post-Merger, PHI will become a subsidiary of EEDC. However, another special purpose entity will be placed between PHI and EEDC in order to implement the ring-fencing measures that Exelon is proposing, which are described in greater detail in the direct testimony of Carim V. Khouzami. Specifically, a new SPE will be created with provisions in its organizational documents designed to insulate PHI and Pepco from potential credit, default and bankruptcy risks of unrelated businesses in the Exelon holding company system, as Mr. Khouzami explains. Pepco, along with the other PHI Utilities, will continue to be subsidiaries of PHI.

8. Q. Does the post-Merger corporate structure mean that there will be multiple layers of management between Exelon and Pepco corresponding to each corporate tier that you described above?

A. No, it does not. Simply because multiple tiers exist within the Exelon corporate structure does not mean that there are ascending layers of corporate management at each tier. To the contrary, Exelon employs a straightforward management structure, which maintains clear, direct lines of reporting and responsibility that do not necessarily track the various intermediary legal entities within Exelon's corporate structure. In that regard, both RF Holdco and the SPE to be created between EEDC and PHI exist only to ring-fence BGE and the PHI Utilities, respectively, and will have no operational role or management responsibility.

9. Q. Explain the role PHI will have in the operation of Pepco following consummation of the Merger.

A. As Mr. Rigby explains in his direct testimony, PHI currently plays an important role in the overall management of Pepco. Based on Mr. Rigby's description of the PHI management structure, PHI's role in the operation of Pepco will align with the management of BGE, ComEd and PECO. As a consequence, when I or other witnesses providing direct testimony refer to "local management" in the context of PHI and Pepco, that term refers generally to PHI and not necessarily the Boards of Directors and officers of Pepco. Mr. Rigby also describes the role of the Regional Presidents for Pepco and each of the PHI Utilities. Exelon plans to retain the Regional President positions with their current duties and responsibilities. As Mr. Rigby explains, the Regional Presidents work closely with the operational side of the business, provide a strong local connection in each jurisdiction and maintain relationships with state and local governments, regulatory officials and other stakeholders in the communities they serve. We envision Pepco's Regional President playing the same role after the Merger.

On or shortly after the effective date of the Merger, PHI will be converted from a corporation to a limited liability company or "LLC." As an LLC, PHI will have a Board of Directors that will function in a fashion similar to that of the Board of Directors of a corporation. Currently, Exelon anticipates a seven-member board with three outside members from the Pepco, ACE and Delmarva Power service areas and four members who will consist of some combination of officers or directors of Exelon and officers of one or more of PHI or the PHI Utilities. The PHI Board of Directors will select the Board of Directors of Pepco, and the Pepco board will choose Pepco's officers.

PHI's common stock will cease to be publicly traded on and after the effective date of the Merger. Therefore, a number of corporate functions associated with having publicly traded common stock, such as investor relations, will no longer need to be performed at the PHI level because Exelon already has those capabilities. The elimination of these functions at the PHI level is one important source of synergies the Merger is expected to produce. PHI will, however, have a President/Chief Executive Officer, Chief Financial Officer, Treasurer and a limited number of other officers, but likely fewer than currently exist.

The authority of the PHI Board of Directors and officers to act on behalf of Pepco and the other PHI Utilities will be delineated in a Delegation of Authority, which I describe in more detail later in my testimony.

10. Q. Please describe the role of the operating utilities' management in Exelon's existing utility management model.

A. The senior management of each Exelon utility is given the authority and responsibility for developing its respective utility business plan and operating and maintenance (“O&M”) and capital budgets. While those business plans and budgets are reviewed by me, Exelon’s CEO and the Executive Committee of Exelon, they have to be approved by the Boards of Directors of the respective utilities. As I previously explained, following the Merger, PHI’s management will align at the same level as the senior management of Exelon’s existing utilities and, therefore, business plans and budgets for Pepco would have to be approved by the PHI Board of Directors that I described previously.

Additionally, the authority and responsibility delegated to local management is clearly delineated in two formal, written documents, namely, a statement of Corporate Governance Principles and a Delegation of Authority. The Delegation of Authority includes, among other things, levels of expenditures and defined categories of decisions that can be authorized solely by the utility’s CEO or by the utility CEO with utility board approval.

Consistent with the clearly established direction, goals and priorities provided by the utility’s business plan and budgets, each utility CEO is held accountable for assuring that safe, reliable and efficient service is furnished to customers and that appropriate fiscal discipline is maintained, consistent with the utility’s service obligations, to remain on-budget. For PHI, its CEO will have this authority and responsibility on behalf of Pepco. As part of this process, Exelon will provide the resources that BGE, ComEd, PECO and PHI, together with its subsidiary utilities, will need to execute their business plans and fulfill their service obligations.

11. Q. What is EU and what is its role in the Exelon utility management model?

A. EU was formed in 2012 upon the completion of the Exelon-Constellation merger. With that merger, BGE joined ComEd and PECO in Exelon's family of utilities. As a result, the utility segment increased to more than 50% of Exelon's earnings before income taxes, depreciation and amortization. Given the greater size of its post-merger utility operations, Exelon determined that it should create a structural vehicle to coordinate the development and oversight of its regulated business. Exelon also concluded that the new management structure should be assigned responsibility for realizing the value inherent in the larger scale of post-merger operations by unlocking the knowledge, expertise and practical experience that otherwise could be isolated within each utility company or within "silos" inside each of those companies. Simply stated, given the breadth and depth of Exelon's utility operations, there was likely to be a precedent or best practice within one or more of its utility operating companies for many aspects of utility operations, and the new management structure was tasked with working with the individual utilities to identify those precedents and best practices and deploy them across the entire enterprise. I describe various examples of the successful cross-pollination and sharing of best practices from the PECO-Unicom and Exelon-Constellation mergers in Section III of my testimony. In short, EU was the solution Exelon developed to facilitate the horizontal distribution of knowledge and expertise and sharing of best practices across all of Exelon's utilities.

As I previously noted, EU is not a legal entity but, rather, is an unincorporated divisional structure that maintains direct lines of reporting between Exelon's utilities and Exelon's senior management. As part of this process, EU helps local utility management develop business plans and budgets and also helps identify and marshal skills, knowledge and resources within Exelon that local utilities may need to successfully implement those plans. EU is also the organizational tool embedded in the management structure for the express purpose of focusing management attention on cooperation and collaboration across the utility business. While there are many ways in which EU pursues that part of its mission, some of the more important ways include driving the processes for identifying and sharing best practices, leveraging economies of scale, and creating efficiencies by standardizing business and operating processes as appropriate and consistent with each company's service obligations. To that end, EU works with each utility's management: (i) to develop its business strategy and establish appropriate performance goals in areas such as safety, reliability and customer satisfaction; (ii) to ensure that the utility remains on track to implement its business plan and achieve its performance goals; (iii) to maintain clear lines of reporting to Exelon management on the performance of EU and each utility; and (iv) to formalize the process for sharing knowledge and best practices among utilities by creating cross-company "communities of practice" organized around common functions, objectives and operational challenges. Additionally, EU has primary responsibility for overseeing and monitoring each utility's compliance with regulatory requirements and adherence to applicable Exelon policies and standards.

12. Q. What is your role in EU?

A. As I previously indicated, I am CEO of EU, a position I assumed when EU was created. While I continue to live in the Philadelphia area, I maintain offices in Philadelphia, Baltimore and Chicago. Following the completion of the Merger, I will have an office in the District of Columbia. As CEO of EU, I have general oversight responsibility for BGE, ComEd and PECO. I am also responsible for EU fulfilling its mission of assisting Exelon’s utilities to work collaboratively to achieve superior operational performance and to provide their customers safe, reliable and efficient service at just and reasonable rates.

13. Q. Earlier, you mentioned that Exelon’s management structure maintains straightforward, direct lines of reporting. Please describe those lines of reporting.

A. The CEOs of individual utilities report to me as Senior Executive Vice President with overall responsibility for Exelon’s regulated utility business. I report directly to Exelon’s CEO, Christopher M. Crane.

The CEOs of the regulated utilities are members of the Exelon Management Executive Committee, which also includes members from other areas of Exelon’s business that are selected by Exelon’s CEO. The Management Executive Committee exists to assist Mr. Crane in leading Exelon. The Management Executive Committee is the body where important policy and operating decisions for Exelon, including Exelon’s utilities, are discussed, analyzed and decided. As members of the Management Executive Committee, the utility CEOs – which will include the CEO of PHI post-Merger – meet with Mr.

Crane at least monthly. Consequently, the CEOs of the operating utilities have direct and frequent access to Mr. Crane and other members of Exelon's senior management team.

14. Q. Will EU and the Exelon management model continue to function in the way you described after the Merger is consummated and the PHI Utilities join Exelon?

A. Yes, they will. Following the Merger, regulated utility operations are projected to contribute 60% and 65% of Exelon's pro forma 2015 and 2016 earnings, respectively. Consequently, the original rationale for creating EU and employing the Exelon utility management model will continue and, in fact, be reinforced by the Merger. Based on the success EU and the Exelon management model achieved with the integration and subsequent operation of BGE, I am confident that PHI and Pepco will also be successfully integrated and operated following the Merger.

15. Q. Does Exelon expect that the local management of Pepco will remain in place following the Merger?

A. Yes, Exelon expects that managers who are "on the ground" in District of Columbia and whom the Commission, stakeholders and customers have come to know and trust will still be on the job after the Merger is completed.

16. Q. Will PHI and Pepco continue to have a strong local presence in the District of Columbia?

A. Yes, they will. In fact, Exelon intends to maintain the headquarters of PHI and Pepco in the District of Columbia. Additionally, Exelon is making specific commitments with respect to charitable giving and community initiatives, which are discussed in the direct testimony of Calvin G. Butler, Jr.

III. SHARING OF BEST PRACTICES FOLLOWING THE PECO-UNICOM AND EXELON-CONSTELLATION MERGERS

17. Q. Briefly describe your experience and involvement in the successful sharing of best practices that followed the PECO-Unicom and Exelon-Constellation mergers.

A. I was directly involved in the integration and sharing of best practices following the PECO-Unicom and Exelon-Constellation mergers. When the PECO-Unicom merger was consummated, I was Vice-President of PECO and, in that capacity, had overall responsibility for the operation and maintenance of PECO's electric and gas transmission and distribution systems. Following the Exelon-Constellation merger, I assumed my current position where I have general oversight responsibility for BGE, ComEd and PECO. After both mergers, the utilities of the merged company became stronger organizations, improved their reliability metrics and had enhanced ability to provide our customers high-quality service. Large numbers of individual best practices were shared across the enterprise following each merger. Some of the most notable examples of best practice sharing following the PECO-Unicom merger involved PECO's adoption of ComEd's seasonal readiness program and detailed capacity planning process and ComEd's adoption of PECO's Preventive Maintenance Program and rigorous safety programs.

Following the Exelon-Constellation merger, best practices identified from among BGE, ComEd and PECO were deployed across all three companies. Some of the more significant examples include the following:

- Extending Exelon's "lock out" and "tag out" ("LOTO") procedures throughout all of Exelon's utilities: LOTO consists of safety procedures used in the electric power industry to ensure that power lines are properly de-energized and not re-energized again before maintenance or servicing work has been completed. Exelon's carefully developed and well-tested LOTO procedures have now been standardized across ComEd, PECO and BGE. In addition to helping our employees stay safe and improving productivity, standardizing "best practice" LOTO procedures enables crews from any one of Exelon's utilities to seamlessly work on the facilities of any other Exelon utility. As a consequence, the performance of inter-company mutual assistance is enhanced and restoration times following system emergencies are reduced. In addition, standardized procedures for working on de-energized equipment were adopted, which improved productivity and reduced outage durations.
- Adoption of criteria developed by ComEd and PECO for prioritizing corrective maintenance work that is identified by circuit patrols: Circuit patrols conduct inspections of distribution circuits. These inspections are designed to do several things, including helping to identify maintenance needs. Implementing an appropriate system for prioritizing corrective

maintenance based on carefully designed criteria has reduced the number of outages caused by equipment failures.

- Optimizing the use and placement of "reclosers": Based on their shared experience, Exelon's utilities have been able to optimize the criteria for, and the use and placement of, "reclosers." Reclosers are circuit breakers designed to automatically open or close, as applicable, when a problem is detected on a line, such as when a tree makes contact with a conductor. Optimal use and placement of reclosers reduce the number of sustained customer outages by isolating the segment of a line where a problem is detected while maintaining service on parts of the line that are not adversely affected.
- BGE's adoption of procedures for rejuvenating the insulation of insulated cable: The extension of this ComEd/PECO best practice to BGE has improved reliability, avoided the need to replace insulated cable prior to the end of its service life, and reduced projected equipment replacement costs.
- BGE's adoption of standards employed by ComEd and PECO to protect its facilities from harmful wildlife interactions: Animals may use man-made structures for dens or nesting sites, foraging sites, or as travel routes, and these activities can cause damage to structures and the equipment they contain. For example, wildlife intrusions into electric power substations and the resulting damage they cause to the electrical equipment can trigger outages of all of the circuits served from those substations. Adopting the

Exelon approach to controlling wildlife interaction with electrical facilities has contributed to a reduction in outages experienced at BGE while also protecting wildlife and the environment.

- BGE's avian management program, analysis of accelerated gas asset replacement programs, use of social media to improve customer satisfaction and lessons learned for supporting fleet warranty claims were identified as best practices and used to align common practices across all of Exelon's utilities.

The process of sharing best practices was an important factor driving BGE's improved reliability metrics. As Mr. Alden explains in his direct testimony, as a result of sharing best practices, the reliability improvements at BGE were achieved without increasing BGE's planned expenditure levels. In addition, as noted in some of the examples cited above, sharing best practices can enhance employee safety and reduce costs.

IV. EXELON'S EMPLOYMENT RELATED COMMITMENTS

18. Q. Please describe Exelon's commitment with regard to post-Merger employment at Pepco.

A. Exelon is committing that, upon approval of the Merger and for two years following consummation of the transaction, it will not permit a net reduction in the employment levels at Pepco due to involuntary attrition resulting from the Merger integration process.

19. Q. Please describe Exelon's commitment with regard to post-Merger compensation.

A. Exelon and PHI are committing to honor the PHI Utilities' existing collective bargaining agreements. It is significant that, as Mr. Rigby explains, Locals 210, 1238, 1307 and 1900 of the International Brotherhood of Electrical Workers, which comprise all of the collective bargaining units that represent employees of PHI, agree the Merger is in the best interest of Pepco and its employees. These four Locals have also recently agreed to contract extensions for an additional three years. Exelon is also committing that for two years following consummation of the transaction, it will provide current and former employees at Pepco compensation and benefits that, in the aggregate, are at least as favorable as the compensation and benefits provided to those employees immediately before the Merger.

V. STANDARD OFFER/DEFAULT SERVICE; LOCAL ELECTRIC COMPETITION; AND WHOLESALE COMPETITION/MARKETPOWER

20. Q. Will the Merger affect the ability or willingness of Pepco to provide standard offer or default service to customers in the District of Columbia?

A. No. Pepco will continue to provide Standard Offer Service ("SOS") to its customers in the District consistent with the District of Columbia Code and Affiliate Code of Conduct. Exelon Generation is currently an active participant in the Power Supply Procurement Process for SOS and, following the closing of the Merger, intends to continue to participate in that process.

21. Q. Will the Merger impact local electricity competition in the District of Columbia?

A. No. The Merger will not have any adverse competitive effects on the District of Columbia's retail energy markets. Each of the PHI Utilities, including Pepco, has divested all of its generation facilities and purchases power only pursuant to requirements contracts to serve its default service load and must-take contracts with Qualifying Facilities entered into under the Public Utility Regulatory Policies Act of 1978 or pursuant to Commission-approved programs such as net energy metering in the District of Columbia. Exelon, under the name Constellation, provides competitive retail service in Washington, D.C., and it plans to continue to do so post-Merger. Exelon will be bound by District of Columbia's Affiliate Code of Conduct and will have in place standards and procedures to prevent preferences and the improper flow of information between Pepco and Exelon's subsidiaries. As a consequence, the Merger will not have any impact on retail competition.

22. Q. Will District of Columbia customers be affected by the Merger of the Joint Applicants' transmission facilities operated by the PJM Interconnection LLC ("PJM")?

A. No. The Merger will not have any impact on wholesale competition and does not raise any market power concerns because all of the PHI Utilities' transmission assets are under the operational control of PJM, which furnishes transmission service pursuant to its FERC-approved Open Access Transmission Tariff.

VI. CONCLUSION

23. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

M.F. ALDEN Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _______(D)

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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF MARK F. ALDEN
FORMAL CASE NO. _____

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is Mark F. Alden. My business address is 110 West Fayette Street, Baltimore, Maryland 21201.

2. Q. By whom are you employed and in what capacity?

A. I am employed by Exelon Corporation ("Exelon") as Vice President, Utility Oversight and Integration. I am responsible for overseeing and ensuring consistency and best practice application across the operations of the three Exelon utilities – Baltimore Gas and Electric Company ("BGE"), Commonwealth Edison Company ("ComEd"), and PECO Energy Company ("PECO"). I report directly to Denis P. O'Brien, Chief Executive Officer of Exelon Utilities.

3. Q. Please describe your professional and educational background.

A. I received a bachelor's degree in civil engineering from Pennsylvania State University and a master's degree in business administration from Saint Joseph's University. I have worked for PECO or its corporate affiliates for the past thirty-two years, starting out as a project manager in PECO's nuclear group and, prior to my current position, serving as Vice President, Customer Operations, for PECO. I have also served as Vice President, Engineering and Services, for PECO and ComEd and my responsibilities in that position included development of investment strategies for overall system reliability improvements at those utilities.

4. Q. Have you previously testified before a utility regulatory agency?

A. Yes. I submitted direct and rebuttal testimony before the Pennsylvania Public Utility Commission ("PA PUC") on behalf of PECO with respect to its 2008 gas base rate filing at PA PUC Docket No. R-2008-2028394.

5. Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is as follows: (1) to provide an overview of Exelon's approach to utility service reliability and the levels of reliability at Exelon utilities, including improved reliability at BGE after its acquisition by Exelon; and (2) to describe the enhanced reliability metrics which Exelon is committed to achieving at Potomac Electric Power Company ("Pepco") upon approval of Exelon's proposed merger with Pepco Holdings, Inc. ("PHI").

II. EXELON'S APPROACH TO RELIABILITY

6. Q. What is Exelon's approach to utility service reliability?

A. Exelon is committed to continuously improving the reliability of its service in each of its utility service territories. This commitment incorporates numerous programs to maintain, protect and improve the electric distribution system at each utility, including proactive inspection, electric infrastructure replacement (such as new substations), and general reliability construction programs (e.g., cable replacement).

7. Q. How does Exelon effectuate this commitment?

A. In order to implement this reliability commitment, Exelon has developed the Exelon Management Model (the "Management Model"), a management system designed to identify and generate best practices for operational excellence at each of its utilities and to share and implement those practices system-wide. The Management Model includes forty-four system-wide core functional area teams (such as Operate and Restore, Preventative and Corrective Maintenance, and System Performance) which are directed by senior leaders and staffed by managers who lead the corresponding functional area at each utility. This structure helps ensure alignment, sharing, and implementation of best practices and initiatives across all utilities and drives improved performance and increased customer satisfaction.

8. Q. How does Exelon measure reliability at its utilities?

A. Our primary measure of reliability is a set of standard metrics established by the Institute for Electrical and Electronics Engineers ("IEEE") which are used in some form by public utility commissions across the country. We are particularly focused on the following two key metrics:

- **System Average Interruption Frequency Index ("SAIFI")**: The average number of sustained interruptions per customer during a year.
- **Customer Average Interruption Duration Index ("CAIDI")**: The average duration of interruptions that a customer experiences during a year.

SAIFI is useful as it indicates the average number of times that a customer may be interrupted over the course of a year, while CAIDI provides the average length of time of those interruptions. I understand from Mr. Gausman's direct testimony that in February 2012 the District of Columbia Public Service

Commission (the "Commission") implemented the Electricity Quality of Service Standards ("EQSS") in the District and that these standards are applicable to SAIFI as well as System Average Interruption Duration Index ("SAIDI") levels for the years 2013 through 2020. SAIDI is another measure of the length of time that customers are without service and is based on the system-wide average duration of outages. As a result, for the District of Columbia, we will also regularly calculate SAIDI, in addition to SAIFI and CAIDI.[1]

We also utilize a variety of other metrics to measure reliability. For example, we track a Customer Satisfaction Index for each Exelon utility, which measures customer satisfaction with a variety of service components, including the ability to restore electric service after an outage.

In addition to calculating and analyzing each utility's performance on these important metrics, we compare Exelon utility performance to the performance of other similar utilities utilizing industry peer groups and best-practice sessions to drive continuous improvement.

9. Q. How have Exelon utilities performed on the key reliability metrics you have described?

A. The effectiveness of Exelon's approach to reliability is reflected in the fact that, in 2013, each Exelon utility maintained its continuing trend of improvement and exceeded its 2012 performance in the key metrics of SAIFI, SAIDI, and CAIDI.

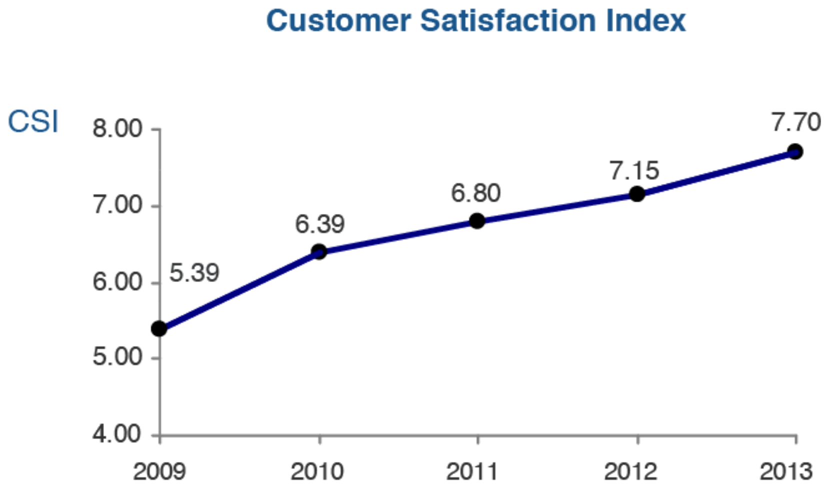
[1] CAIDI=SAIDI÷SAIFI.

I have included a set of graphs in JOINT APPLICANTS (D)-1 to my testimony, which depicts 2013 performance levels on these metrics as well as the trend of improvement over the last four years for the Exelon utilities. In each graph, the declining index reflects improved reliability for customers: a lower SAIFI corresponds to a reduced number of interruptions and a lower SAIDI and CAIDI (which are shown in minutes over time) correspond to shorter outage duration.[2] We also compare the performance of Exelon utilities to other utilities, and the SAIFI, SAIDI and CAIDI results place both ComEd and PECO in the top quartile of similar utilities in the U.S.

10. Q. Mr. Alden, how would you characterize the change in reliability metrics at BGE since its acquisition by Exelon?

A. BGE's reliability metrics have improved significantly since BGE became part of the Exelon family of utilities in 2012. For example, as shown in the JOINT APPLICANTS (D)-1, the average time to restore service to BGE customers who experienced a sustained interruption declined by almost 32%. That enhanced reliability is also reflected in other metrics that we measure, such as the Customer Satisfaction Index, which also improved following Exelon's acquisition of BGE, as shown below:

[2] The calculations reflected in the following graphs are based on the IEEE 2.5 Beta methodology, which is a common standard developed by IEEE to address the inclusion and exclusion of major event days in the calculation of IEEE reliability metrics.



11. Q. Mr. Alden, did Exelon increase capital spending or operations and maintenance expenditures at BGE after the merger in order to obtain these reliability improvements?

A. No, it did not. ComEd and PECO worked closely with their colleagues at BGE to share best practices, as described by Mr. O'Brien. As a result, we were able to achieve the improved reliability and customer satisfaction metrics at BGE without increasing planned expenditure levels.

12. Q. What types of assistance do Exelon utilities provide to each other in the event of major storms?

A. The Exelon utilities are integrated with each other in a variety of ways that enhance reliability. Perhaps most importantly for many customers, BGE is now fully integrated with ComEd and PECO in its response to major storms. This integration facilitates the deployment of Exelon utility crews quickly and safely between utility service territories and permits teams from all three companies to begin work almost immediately upon arrival in another Exelon utility service territory through the use of such practices as the standardized "Lock Out" and "Tag Out" ("LOTO") program described by Mr. O'Brien.

13. Q. Is the ability to dispatch utility crews from other Exelon utilities any different than the resources that are available under mutual assistance agreements between unaffiliated utilities?

A. Yes. Under utility mutual assistance agreements, there is no guarantee that other utilities will provide resources during or after a storm event, particularly when those other utilities may also be facing a large number of actual or potential outages from a large regional storm. By contrast, Exelon utilities are committed to making their storm restoration resources available to their affiliates on a priority basis, and the use of LOTO and other best practices enables those resources to be more efficient and productive than those that may be obtained from an unaffiliated utility. We are also able to pre-position Exelon-affiliated crews before actual storm events to ensure that those crews will be ready to go to work as soon as an actual storm subsides.

As an example, in response to the 2012 Derecho storm that resulted in more than 748,000 outages in BGE's service territory, PECO utility crews were able to provide over 25,000 full-time equivalent hours of assistance to BGE. The work of these crews reduced the duration of storm restoration efforts by approximately 24 hours.

Further, because Exelon utilities serve several major cities including Chicago, Philadelphia, and Baltimore, we are very familiar with and experienced in the special issues that arise in serving a large metropolitan service territory such as Washington, D.C.

III. ENHANCED RELIABILITY COMMITMENTS FOR PEPCO

14. Q. In his testimony, Mr. Gausman explained that Pepco must meet certain reliability requirements under District of Columbia EQSS standards. Will Exelon achieve those requirements?

A. Yes, all EQSS requirements will be achieved by Exelon and Pepco following the merger. Furthermore, as Mr. Crane has explained, we are confident that the Exelon/PHI combination will allow Pepco to do better than merely meet the minimum requirements. Following the merger, the combined companies expect that Pepco we will be able to exceed the EQSS requirements and improve Pepco's reliability through the integration of Pepco with the other Exelon utilities consistent with the Exelon approach to reliability I have described.

Exelon will therefore commit to Pepco achieving the following SAIFI and SAIDI average calculated for the three-year 2018-2020 period:

SAIFI: 0.54

SAIDI: 107

Compliance with the above commitments will be measured following the end of 2020 using the Commission's current methodology for calculating SAIFI and SAIDI, and exclusion of major event days. Pepco will report its performance against these commitments to the Commission no later than April 1, 2021. Pepco's failure to achieve these commitments will result in financial penalties, as described by Mr. Khouzami in his testimony.

Exelon's proposed levels of SAIFI and SAIDI, on average, for the 2018-2020 period, backed by financial penalties, reflect our substantial commitment to Pepco's customers that reliability will continue to improve and, in fact, will exceed the EQSS reliability requirements described in Mr. Gausman's direct testimony. Furthermore, the reliability improvements I have described will be achieved without increasing reliability-related capital and operations and maintenance expenditures above the levels in Pepco's existing long-range plans absent changes in law, regulations, or extreme weather events such as the Derecho storm, requiring increases in reliability-related spending to restore service and facilities.

15. Q. Is Exelon committed to support the Pepco DC undergrounding project described by Mr. Gausman in his direct testimony?

A. Yes. I understand from Mr. Gausman that on June 17, 2014, Pepco filed its Application, Testimony and Triennial Plan with the Commission for final approval prior to the start of work. Exelon fully supports this undergrounding work to improve reliability in the District of Colombia. The improved SAIFI and SAIDI commitments above are in addition to those to be achieved by the DC undergrounding project.

16. Q. Have you calculated Pepco's performance using the same methodology for the most recent three years?

A. Yes. Using the same methodology, Pepco's three-year historical averages (2011-13) of SAIFI and SAIDI are as follows:

SAIFI: 1.03

SAIDI: 149

The three-year average reliability commitments proposed by Exelon which I have described above represent an increase of 47.9% and 27.9% above these three-year actual average performance levels.

17. Q. Why are you proposing to calculate whether or not Exelon has met its reliability commitment at Pepco using a three-year average of performance in the 2018-2020 period?

A. We have proposed using a three-year historical average to account for any abnormal weather variability that could distort results if only the year 2020 was selected for measurement of Pepco's performance. If a three-year average is used, no additional weather normalization of Pepco's performance will be required.

18. Q. If Pepco is not measured on its reliability commitments until the conclusion of 2020, will that delay enhancements to Pepco's reliability?

A. No. As Mr. Gausman explains, Pepco already is required to achieve higher reliability metrics. Exelon is committed to ensuring that Pepco achieves those improvements, and therefore Exelon's additional reliability enhancements are best measured at the end of the period in which Pepco is expected to achieve its current reliability goals. Measurement of our success following 2020 will not delay deployment of Exelon best practices at Pepco, or Pepco's achievement of its current reliability obligations.

IV. CONCLUSION

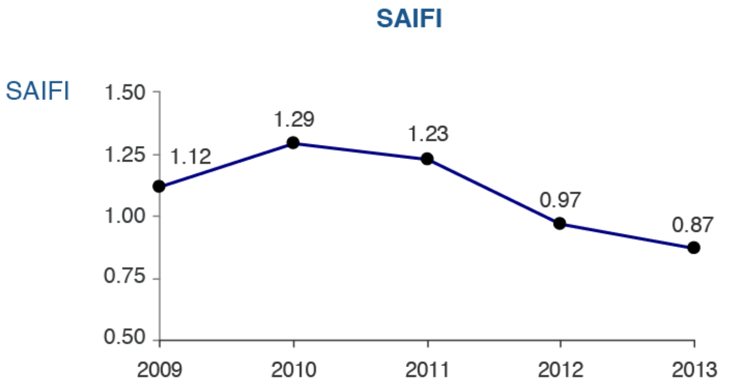
19. Q. Does this conclude your direct testimony?

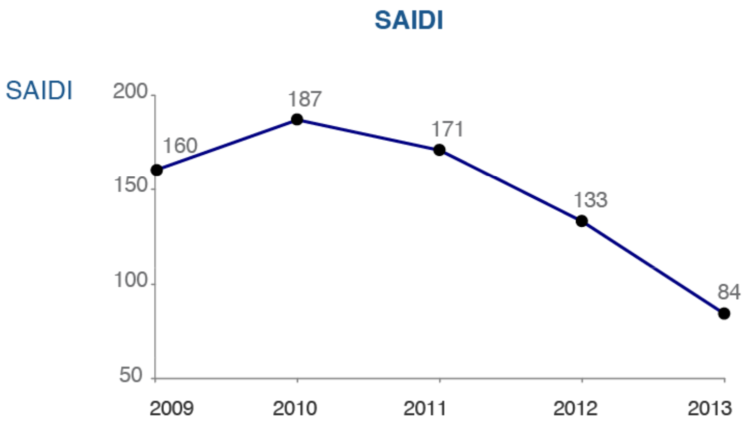
A. Yes

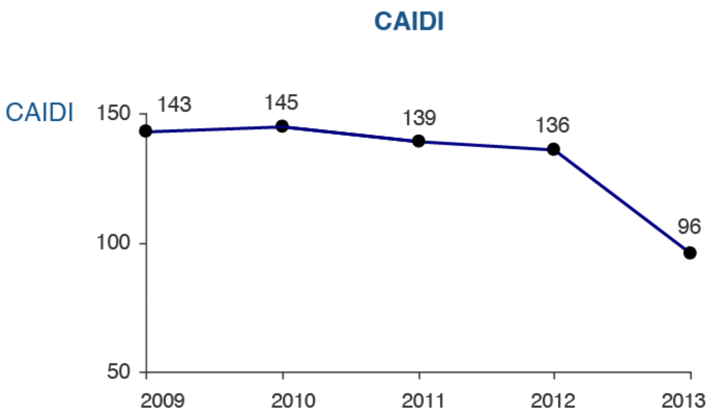
M.F. ALDEN Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _______(D)-1

Baltimore Gas & Electric







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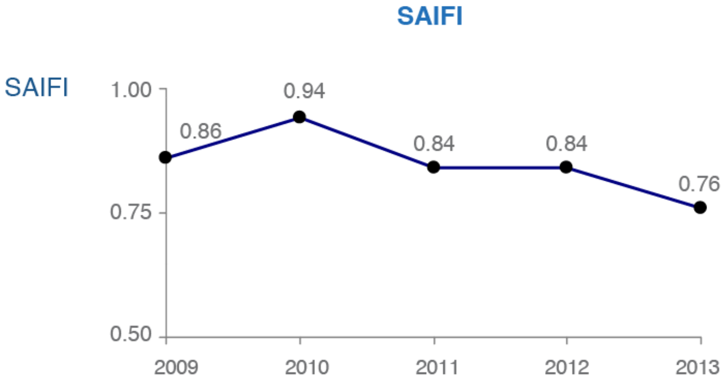

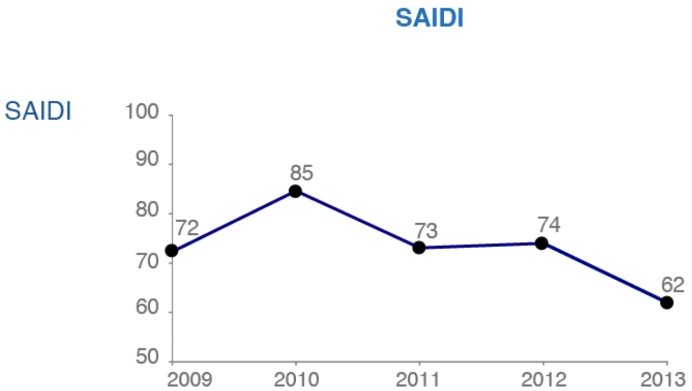

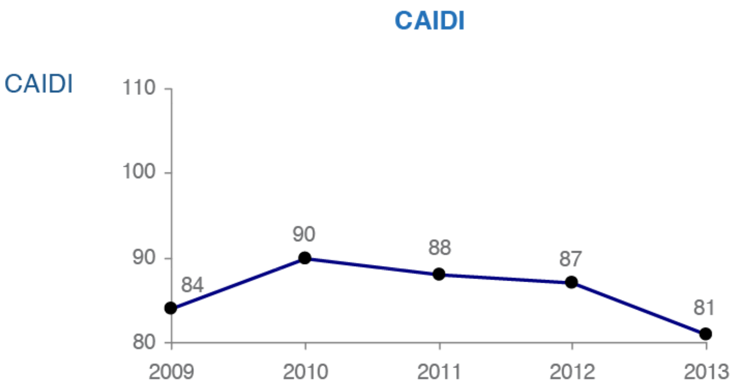

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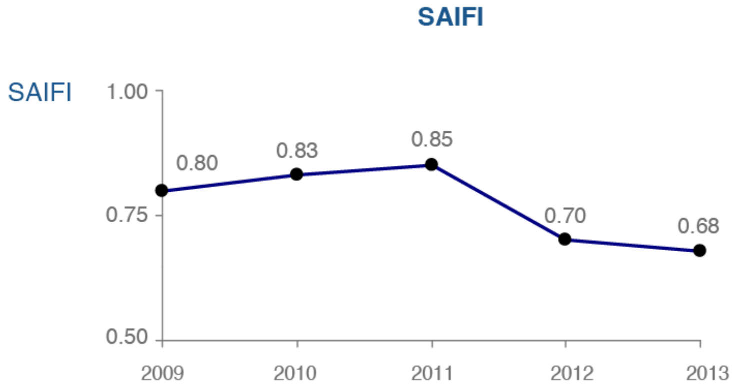
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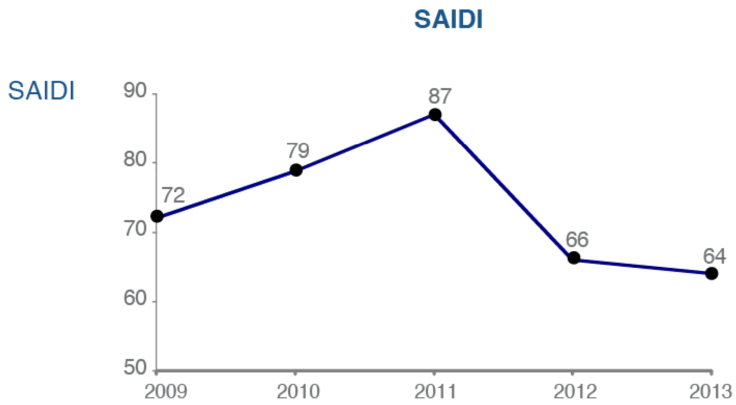
2011
2012
2013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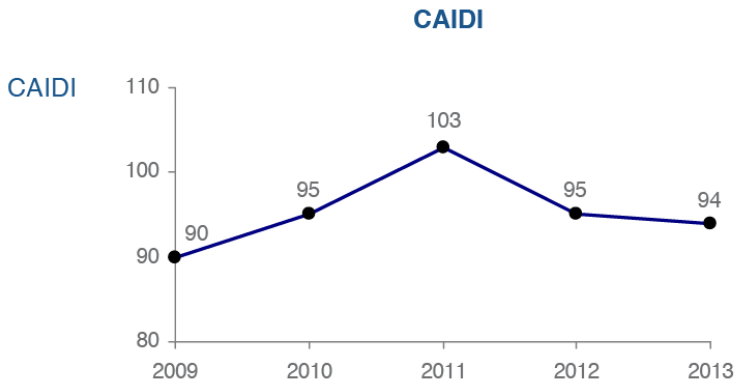
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2009
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2012
2013

W.M. GAUSMAN Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _____(E)

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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF WILLIAM M. GAUSMAN
FORMAL CASE NO. _____

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is William M. Gausman. My business address is 701 Ninth Street NW, Washington, DC 20068.

2. Q. By whom are you employed and in what capacity?

A. I am employed by Pepco Holdings, Inc. ("PHI") as Senior Vice President, Strategic Initiatives. I am responsible for the oversight of strategic projects that focus on the long term support of the transmission and distribution systems. This includes the implementation of PHI's Advanced Metering Infrastructure, the procurement of energy (both gas and electric), and compliance with both North American Electric Reliability Corporation and state reliability standards to ensure the safe and reliable operation of the electric system. I have previously been responsible for the engineering of all reliability programs and the design of all assets that support the transmission and distribution of electric service across the service areas of all PHI utilities.

3. Q. Please describe your professional and educational background.

A. I hold a Bachelor of Science degree in Electrical Engineering Technology from Temple University. I joined Potomac Electric Power Company ("Pepco") in 1974 as a Project Engineer overseeing the construction of high voltage transmission facilities. I have served in various management positions within

Pepco and PHI, with increasing responsibility for the operation, maintenance, and construction of both the transmission and distribution systems. From 1977 through 1988, I served as Superintendent of Underground Lines and as Manager of Electric System Operation and Construction. In 1988, I was promoted to General Manager – Power Delivery, and in 2001 I became General Manager – Asset Management. In 2002, I was named Vice President – Asset Management of Pepco. After Pepco's merger with Conectiv, I became Vice President – Asset Management over the combined PHI organization. In 2008, I was promoted to Senior Vice President Asset Management and Planning, and assumed my current position in October 2010.

During my career with PHI, I have also served as an advisor to various industry organizations including the Electric Power Research Institute Distribution Committee, the Southeastern Electric Exchange Executive Committee and the Edison Electric Institute ("EEI") Distribution Committee. I am currently a member of the EEI Transmission Executive Advisory Committee. I am also a member of Leadership Greater Washington.

4. Q. Have you previously testified before a utility regulatory agency?

A. Yes. I have testified before The District of Columbia Public Service Commission (the "Commission") on numerous occasions on reliability, system performance, AMI, and other issues.

5. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe the current reliability commitments of Pepco.

II. DISTRICT OF COLUMBIA RELIABILITY REQUIREMENTS

6. Q. Mr. Gausman, please provide an overview of Pepco's reliability commitments.

A. Certainly. Pepco is committed to delivering safe and reliable service to all of its customers, and Pepco's success in meeting this commitment is measured using a set of standard reliability metrics created by the Institute for Electrical and Electronics Engineers ("IEEE"). The following metrics are used in the District of Columbia:

- **System Average Interruption Frequency Index ("SAIFI")**: The average number of sustained interruptions per customer during a year.
- **System Average Interruption Duration Index ("SAIDI")**: The average duration of sustained interruptions per customer during a year.

SAIFI is calculated by dividing the total number of sustained customer interruptions in a year by the total number of utility customers, and provides insight into the frequency of customer interruptions on a system-wide basis. Similarly, SAIDI is calculated by dividing the sum of all sustained customer interruption durations by the total number of customers served, and indicates how long customers were without service. Lower SAIFI and SAIDI values reflect fewer interruptions and shorter outage durations, respectively.

7. Q. What are the reliability performance standards in the District of Columbia?

A. Pepco is required to meet reliability standards contained in the Electricity Quality of Service Standards ("EQSS") as enacted by the District of Columbia

Public Service Commission in February 2012.[1] Under the EQSS, Pepco is required to meet the following levels of reliability under the above metrics:

	2014	2015	2016	2017	2018	2019	2020
SAIDI (hours)	2.43	2.21	2.00	1.81	1.65	1.44	1.35
SAIFI	1.09	1.05	1.02	0.98	0.95	0.92	0.89

These reliability performance targets established by the Commission exclude major service outages. Consistent with Commission requirements, Pepco files an annual report describing its success in achieving the required level.

8. Q. What types of programs does Pepco currently have in place to meet its reliability commitments?

A. Pepco has an extensive set of programs designed to meet these commitments. These programs incorporate proactive replacement and upgrading of existing infrastructure, the addition of new facilities to increase capacity, and corrective maintenance to maintain and improve the reliable operation and performance of system equipment and to reduce the frequency and duration of outages as measured by SAIFI and SAIDI, respectively. Pepco's reliability programs include the following initiatives:

- Vegetation Management: For overhead systems, vegetation management (i.e., tree trimming) is Pepco's largest single preventive maintenance program. Pepco currently has a four year cyclical program of tree trimming. This program is designed to maintain clearances between

[1] District of Columbia Municipal Regulations Title 15, Chapter 36, Electricity Quality of Service Standards, (§3603). Formal Case No. 982, *In re Investigation of the Potomac Elec. Power Co. Regarding Interruption to Elec. Energy Service*; Formal Case No. 1002, *In re Joint Application of Pepco and the New RC, Inc. for Authorization and Approval of Merger Transaction, Notice of Final Rulemaking*, §3603.11 (Feb. 24, 2012).
[1] *Id*. §3603.11(a).

vegetation and overhead facilities, to reduce tree caused outages and to minimize equipment failures. Efficient implementation of strategic and definitive cyclical vegetation management programs throughout the electric distribution industry has proven to minimize incidental contact between vegetation and overhead distribution circuits, leading to improved SAIFI and SAIDI.

- Feeder Improvement: These projects consist of activities designed to address reliability based on historic performance of distribution feeders, which are medium voltage power lines transferring power from the substation to the distribution transformers. The focus of these projects is to arrest negative trends and return a feeder's performance to acceptable levels.
- Underground Residential Distribution ("URD") Cable Replacement and Enhancement: The purpose of the URD Program is to identify, analyze and initiate corrective actions for the mitigation of URD cable failures (mostly due to aged cable, 1970's and 1980's vintages) and to ensure the ongoing integrity of the URD system, in terms of reliability, safety and cost. A focused approach is used to identify sections of underground cable that are approaching the end of their reliable life and to replace and/or repair such sections of cable before multiple interruptions are experienced by customers. The selection criteria for the URD Program include recent cable failure history, number of customers served, system design, cable design and cable vintage.

- Distribution Automation: Pepco recognizes the benefits of deploying smart grid technology to improve infrastructure reliability, enhance the customer experience, and increase interaction levels with the grid. Pepco's distribution automation approach involves the deployment of advanced control systems across the distribution system, which can automatically identify and isolate trouble spots in the system in real time and restore service to customers in the unaffected parts of the system.
- Load Growth and Load Maintenance: Planning for future load growth starts with the development of load growth projections. Peak load forecasts are developed for three years to allow adequate time to complete routine construction work. Longer range forecasting (4 to 10 years) is used to develop advance plans for large construction projects that require more than two or three years to complete, to identify the need for additional supply capacity at existing substations, for new substation capacity and to develop advanced plans for the higher voltage substation supply (i.e., 34.5 kV to 230 kV systems). Accordingly, the foregoing planning process supports both new customer growth as well as increased reliability of the electric system.
- PEPCO-DC Undergrounding Project: Over the past several years, severe weather resulted in a large number of power outages in the District, imposing significant costs and problems for District residents and businesses. In response to the outages, Mayor Vincent Gray formed a task force to provide advice on actions that may be taken to reduce future

storm-related power outages, including the undergrounding of power lines. The recommendations also enumerated the need for a significant plan to be implemented in order to upgrade electric distribution infrastructure so that it may withstand more frequent weather events. On June 17, 2014 Pepco filed its Application, Testimony and Triennial Plan with the Commission for final approval prior to the start of work. We expect this plan to reduce the number of outages that District of Columbia customers will experience and improve the overall performance of the distribution system.

9. Q. Mr. Gausman, do you believe that Pepco will meet the EQSS reliability requirements if the proposed merger is approved?

A. Yes, I do. Pepco's management and engineers have reviewed the commitments and programs I have described with Mr. Alden and other members of Exelon Corporation's ("Exelon's") utility integration team, and we are confident that we will continue to meet our current and proposed reliability commitments following the merger. I am also confident that, as part of the Exelon family of utilities, we will identify additional best practices from the Exelon utilities so that our reliability programs will continue to improve and we will be able to achieve the enhanced reliability commitments that Mr. Alden discusses in his testimony.

10. Q. Mr. Gausman, do you believe that Pepco will complete the Pepco-DC Undergrounding project if the Merger is approved?

A. Yes. Based on my discussions with Mr. Alden and members of Exelon's integration team, Exelon is committed to moving forward with and completing the undergrounding project for the benefit of the District of Columbia and its residents.

III. CONCLUSION

11. Q. Does this conclude your direct testimony?

A. Yes.

C.V. Khouzami Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _____ (F)

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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF CARIM V. KHOUZAMI
FORMAL CASE NO. _____

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Carim V. Khouzami. My business address is 750 East Pratt Street, Baltimore, Maryland 21202.[1]

2. Q. By whom are you employed and in what capacity?

A. I am a Senior Vice President of Baltimore Gas and Electric Company ("BGE") and am now serving as Chief Integration Officer for the proposed Merger (the "Merger") of Exelon Corporation ("Exelon") and Pepco Holdings, Inc. ("PHI") (including its utility subsidiaries, Potomac Electric Power Company ("Pepco"), Delmarva Power & Light Company ("Delmarva Power") and Atlantic City Electric ("ACE") (the "PHI utilities")).[2] Prior to assuming the position of Chief Integration Officer, I served as BGE's Chief Financial Officer and Treasurer.

3. Q. Please describe your responsibilities as Chief Integration Officer.

A. As the Chief Integration Officer for Exelon, I am working with Donna Kinzel (the PHI Chief Integration Officer) to lead the Integration Office for the Merger and report directly to an Integration Steering Committee comprised of

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[1] This is my interim business address associated with my role as Chief Integration Officer. My BGE business address is 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

[2] In my testimony, I will refer to the applicants identified in the Application as the "Joint Applicants". The Joint Applicants include Pepco, Exelon, and PHI.

top-level executives from all Exelon business areas involved in the Merger. The Integration Office has oversight of Merger integration activities with responsibilities for establishing strategic, financial, and operational priorities, overseeing development and execution of integration plans, and making recommendations to resolve integration issues.

4. Q. Please describe the responsibilities you have held as Senior Vice President, CFO and Treasurer.

A. My responsibilities have included managing the financial condition of BGE and employing financial policies that maintain the financial health and stability of the utility, enabling BGE to obtain the capital necessary to both provide safe and reliable service and maintain a sound capital structure. In my capacity as CFO, I have had oversight of BGE's accounting, financial reporting, financial planning and budgeting, and tax functions, as well as BGE's internal control structure. As Treasurer, I have been responsible for managing BGE's relationship with the financial community and with the credit rating agencies.

5. Q. What is your educational background?

A. I hold a Bachelor of Arts degree in Economics and Communication Studies from Vanderbilt University and a Master's Degree in Business Administration from Columbia University.

6. Q. Please describe your professional experience and affiliations.

A. I joined Constellation Energy Group, Inc. ("Constellation Energy") in February 2005 and served in various positions of increasing responsibility before being appointed Executive Director, Investor Relations in 2009. During that time, I managed Constellation Energy's relationships with shareholders and analysts. In January 2010, I assumed the additional responsibility of leading Constellation Energy's corporate financial planning and analysis activities. In January of 2011, I was appointed to my position as Treasurer and CFO of BGE. In 2013, I was promoted to Senior Vice President, Treasurer, and CFO of BGE.

Prior to joining Constellation Energy, I worked as an Associate at Bear, Stearns & Co. Inc., primarily focusing on mergers and acquisitions and financing transactions within the financial institutions and insurance sectors. I currently serve on the Board of Directors of two local non-profit organizations – the Port Discovery Children's Museum and the Baltimore Urban Debate League.

7. Q. Have you previously testified before a state utility commission?

A. Yes. I testified before the Maryland Public Service Commission in Case No. 9299, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in Its Electric and Gas Base Rates*, which was filed in July 2012.

8. Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss: (1) finance and accounting issues associated with the Merger, including Exelon's related commitments; and (2) the Merger integration process and estimated savings and synergies. Specifically as to the finance and accounting matters, I will describe the economic terms of the Merger, the source of funds to be used for the Merger, and the combined company's financial strength. I also will describe Exelon's accounting commitments, its commitment to ring-fence PHI and Pepco, from Exelon's other entities and operations, and Exelon's commitments to ensure the financial strength of Pepco. Additionally, I will testify regarding the accounting treatment of the Merger for Pepco following the closing of the Merger and why that treatment will not impact customer rates. As to Merger integration and synergies, I will provide an overview of the integration process and associated timelines as well as the estimated savings we project to be realized by Pepco. Finally, I will describe changes in affiliated agreements for shared services..

II. OVERVIEW OF THE MERGER TRANSACTION

9. Q. Please describe the economic terms of the Merger.

A. Exelon will acquire PHI for approximately $6.8 billion. Upon consummation of the Merger, each PHI shareholder will receive $27.25 in cash for each outstanding share of PHI common stock not held by PHI, Exelon, Merger Sub, a PHI or Exelon affiliate, or a dissenting PHI stockholder properly asserting appraisal rights.[3] The common stock of Exelon will be unaffected by the merger, with each issued and outstanding share of stock remaining outstanding following the Merger. Moreover, the Merger will not change the terms or character of the debt of Exelon currently outstanding and will have no effect on the outstanding debt securities or the capital structure of Pepco or any other PHI subsidiary utilities.

[3] Additionally, to protect PHI shareholders, Exelon is pre-funding a "reverse break-up fee" through a Subscription Agreement for Series A Non-Voting Non-Convertible Preferred Stock (the "Subscription Agreement"). Per the terms of the Subscription Agreement, on April 30, 2014, Exelon purchased 9,000 shares of Series A Non-Voting Non-Convertible Preferred Stock ("Preferred Shares") issued by PHI for an aggregate purchase price of $90 million ("Initial Purchase"). Exelon will purchase an additional 1,800 Preferred Shares for a purchase price of $18 million every ninety days following the Initial Purchase until the earlier of: (1) the purchase of an aggregate of 18,000 Preferred Shares; (2) the closing of the Merger; or (3) the termination of the Merger Agreement. The Preferred Shares will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly.

10. Q. Please explain how Exelon proposes to finance the Merger.

A. Exelon has the necessary financial ability to complete this transaction and has obtained a bridge loan agreement to fund the acquisition pending completion of the permanent financing. Exelon's strong balance sheet will enable it to source permanent financing for the purchase price using a balanced mix of debt and equity along with cash on its balance sheet. We plan to fund roughly 50 percent of the acquisition price from the proceeds of debt to be issued and serviced by Exelon at the holding company level. The remaining portion of the transaction will be funded with proceeds from issuing Exelon common stock and mandatory convertible securities and cash from the sale of non-core assets at Exelon Generation. Exelon plans that the permanent financing will be in place before the Merger closing.

11. Q. Will transaction costs associated with the Merger be recovered in Pepco's rates?

A. No. As stated in the Application, and consistent with Exelon's practice in the Exelon-Constellation Energy merger, Exelon will not pass along to Pepco customers transaction costs incurred in connection with consummation of the Merger. The categories of transaction costs incurred in connection with consummation of the Merger which will not be recovered from utility customers are: (1) consultant, investment banker and legal fees, (2) change in control payments, (3) costs associated with the shareholder meetings and a proxy statement related to the Merger approval by PHI shareholders and (4) costs associated with Exelon's financing for the Merger.

12. Q. Please describe the corporate structure that will result from the Merger transaction.

A. PHI will become a limited liability company and an indirect, wholly-owned subsidiary of Exelon; PHI's stock will no longer be publicly traded. Specifically, PHI will become the direct subsidiary of a bankruptcy-remote special purpose entity ("SPE") being created to "ring-fence" PHI and the PHI utilities, which, in turn, will be a direct subsidiary of Exelon Energy Delivery Company, LLC ("EEDC").[4] EEDC is, and will remain, the direct parent of Commonwealth Edison Company ("ComEd"), PECO Energy Company ("PECO"), and RF Holdco, LLC, which is the SPE that owns BGE. PHI's current unregulated businesses (including PHI Service Company, Potomac Capital Investment Corp., Pepco Energy Services, Inc. and related companies) will be transferred from the PHI portion of the holding company structure and will become subsidiaries outside the PHI ring-fenced structure. Pepco and Conectiv will remain as PHI's direct subsidiaries, while Delmarva Power and ACE will continue as Conectiv's subsidiaries.

A corporate organization chart of the post-Merger corporate structure, showing the placement of PHI and its regulated utilities, is attached to the Application as Exhibit 4.

13. Q. What is an SPE and what is its role?

A. An SPE – special purpose entity - is a corporate entity created to provide structural separation of a subsidiary from its parent or affiliates. For a regulated

[4] Ring-fencing is explained later in my testimony.

utility, the structural separation provides protections from exposure to financial risks that may be experienced by the parent company or by unregulated affiliates, such as Exelon generation and nuclear operations. Here, because the SPE serves to separate PHI from EEDC and its other Exelon affiliates, PHI will be an indirect, rather than a direct, subsidiary of Exelon, and as a result, Pepco will benefit from additional insulation from perceived potential risks associated with Exelon's holding company structure and its ownership and operation of nuclear generation.

III. FINANCIAL STRENGTH OF EXELON AND PEPCO, POST-MERGER

14. Q. Please provide an overview of the financial position of the combined company.

A. The Merger builds upon the existing financial strength of Exelon and of PHI to create, both immediately and in the long term, a combined company that is on firm financial footing, with a financial strength similar to that of each of the Joint Applicants currently. The combined company will strive to maintain strong financial metrics, with investment grade ratings and financial discipline.

Exelon is dedicated to maintaining solid investment grade ratings for the combined company and for Pepco. Since the announcement of the Merger, the credit rating agencies have affirmed the credit ratings and stable outlook for Exelon, PHI, and their respective utilities. Exelon places great importance on the maintenance of investment grade credit ratings. Since Exelon's addition of BGE, BGE has not only maintained, but improved, its credit ratings.

15. Q. What is the proposed capital structure of Pepco post-merger?

A. To support the financial condition and solid investment ratings of Pepco, Exelon is committed to target an average equity level of at least 48% in Pepco as well as the other PHI utilities for ratemaking purposes.

IV. RING-FENCING MEASURES

16. Q. What is meant by ring-fencing?

A. "Ring-fencing" refers to the implementation of measures, including certain key legal protections, for specific affiliates within a holding company structure in order to protect such affiliates and their assets. A primary goal of ring-fencing is to provide the ring-fenced entities with "bankruptcy remoteness" from the rest of the holding company structure, such that a bankruptcy filing associated with other parts of the corporate organization, including the holding company itself, would not be expected to result in a bankruptcy of the ring-fenced entities. In practical terms, ring-fencing measures serve as safeguards to ensure a utility is shielded from events at a parent corporation or its other subsidiaries. Such measures legally wall-off elements of a utility's finances and assets from the parent company and its businesses, while still allowing operational efficiencies and the positive flow of best business practices from one utility to another. An additional benefit of ring-fencing is that it allows differentiation of risk profiles among affiliates or between an affiliate and its corporate parent.

17. Q. Are ring-fencing measures currently in effect at any of Exelon's utilities?

A. Yes. The Maryland Public Service Commission adopted a series of ring-fencing measures for BGE in both Case No. 9173, Phase II, Order No. 82986 (Oct. 30, 2009) and in Case No. 9271, Order No. 84698 (Feb. 17, 2012). In addition, both PECO and ComEd have in place respective sets of ring-fencing measures that are intended to maintain independence in the management and direction of the companies.

18. Q. Is Exelon committing to employ any ring-fencing measures for the PHI utilities?

A. Yes. Exelon has committed to a suite of ring-fencing measures that are some of the strongest safeguards employed nationwide. The protection afforded by ring-fencing measures has been recognized by both regulators and credit rating agencies, as I explain later. The PHI utilities will be protected from business, financial and operational risk exposures associated with the other Exelon subsidiaries, including the other Exelon utilities and Exelon's unregulated operations and activities (*e.g.* nuclear operations), through the creation and use of a bankruptcy-remote SPE. In addition, Exelon and PHI will commit to implement the following ring-fencing arrangements for at least five years following completion of the Merger, absent permission from the District of Columbia Public Service Commission (the "Commission") to act otherwise:

- Pepco will maintain its separate existence and separate franchise privileges;
- Pepco will maintain separate books and records;
- Pepco's books and records pertaining to its operations in the District of Columbia will be available for inspection and examination by the Commission;
- Pepco will maintain separate debt so that it will not be responsible for the debts of affiliate companies and preferred stock, if any, and Pepco will

maintain its own corporate and debt credit rating, as well as ratings for long-term debt and preferred stock.

Provisions comparable to those described above will also be adopted by PHI to assure its separateness from the SPE, the PHI utilities, Exelon and other Exelon affiliates.

19. Q. Please describe the ring-fencing measures associated with the SPE that Exelon is proposing to protect the PHI utilities.

A. As previously explained, PHI will become a subsidiary of the SPE being created to ring-fence the PHI utilities, which in turn, will be a subsidiary of EEDC. The sole purpose of the SPE will be to hold 100% of the equity interests in PHI. Exelon will cause EEDC to transfer the PHI shares to the SPE as an absolute conveyance or "true sale" with the intention of removing the PHI shares from the bankruptcy estate of Exelon. Exelon has committed that the SPE will have adequate capitalization for the nature of its business. The SPE will have no employees and no operational functions other than those related to holding the equity interests in PHI.

The Board of Directors of the SPE will have one independent director. The independent director will be an employee of an SPE administration company in the business of protecting SPEs. A voluntary petition for bankruptcy by the SPE or any amendment to the organizational documents of the SPE that would remove this requirement or other ring-fencing requirements will require the approval of the entire Board of Directors of the SPE, including the independent director. In addition, the SPE will issue a non-economic interest (the "Golden

Share") in the SPE to an SPE administration company in the business of protecting SPEs and separate from the SPE administration company retained for the SPE independent director position. A voluntary petition for bankruptcy by the SPE or any amendment to the organizational documents of the SPE that would remove this requirement or other ring-fencing requirements will require the affirmative consent of the holder of the Golden Share.

The SPE will maintain arms-length relationships with Exelon, PHI, and PHI's subsidiaries, including Pepco. At all times, the SPE will hold itself out as a separate entity from each of Exelon, PHI, and PHI's subsidiaries, will conduct business in its own name, and will not assume liability for the debts of Exelon, PHI, or PHI's subsidiaries. To this end, the SPE's funds will not be commingled with the funds of Exelon, PHI, or PHI's subsidiaries; the SPE will maintain a separate name from and will not use the trademarks, service marks or other intellectual property of Exelon, PHI, or PHI's subsidiaries; and the SPE will maintain separate books, accounts and financial statements reflecting its separate assets and liabilities.

Exelon anticipates obtaining a legal opinion that, as a result of the ring-fencing measures it proposes to implement, a bankruptcy court would not consolidate the assets and liabilities of the SPE with those of Exelon, in the event of an Exelon bankruptcy, or the assets and liabilities of PHI with those of either the SPE or Exelon, in the event of a bankruptcy of either of those entities.

20. Q. Do the rating agencies treat BGE differently, relative to the rest of Exelon, due to the ring-fencing measures that were previously put in place?

A. Yes. In light of the credit insulation provided by the ring-fencing measures adopted for BGE, the rating agencies have indicated that they view the credit quality of BGE on a stand-alone basis, which is reflected in the credit ratings of BGE. Specifically, subsequent to institution of BGE's ring-fencing measures in 2009, S&P raised the corporate credit rating of BGE to BBB+, which became two notches higher than the BBB- rating of its then-parent, Constellation. The upgrade reflected the stand-alone credit quality for BGE. This ratings change reflected S&P's views on the structural protections put in place to insulate BGE from Constellation. Currently, BGE enjoys a credit rating of A-, which is still two notches higher than the BBB rating of its parent, Exelon.

21. Q. Have the rating agencies indicated how they will treat the ring-fencing of the PHI Utilities?

A. Yes. S&P has already commented that, in affirming the ratings of PHI and its subsidiaries, the expectation is that the transaction will provide credit insulation for the subsidiaries sufficient to support ratings above the group credit profile of Exelon.

22. Q. Is Exelon making any commitments regarding the administration of the ring-fencing measures you have described?

A. Yes. PHI and Pepco will amend their charters and by-laws to include a unanimous vote of the Board of Directors is required to file a voluntary bankruptcy petition.

V. MERGER ACCOUNTING

23. Q. Please describe the general requirements associated with purchase accounting as they relate to the Merger.

A. For accounting purposes, Exelon is considered the purchaser of PHI pursuant to the terms of the Merger. As such, Exelon will be required by U.S. Generally Accepted Accounting Principles ("GAAP") to apply purchase accounting to record the Merger transaction in its consolidated financial statements. Under purchase accounting, the sum of the purchase price paid for the common stock of PHI plus the consolidated debt recorded on PHI's balance sheet would be allocated to the assets acquired and the liabilities assumed from PHI based on the fair values of such assets and liabilities as of the acquisition date. If the purchase price for PHI common stock plus PHI debt exceeds the fair value of the net assets acquired, the excess will be recorded as goodwill. Alternatively, if the fair value of the net assets acquired exceeds the purchase price for PHI common stock plus PHI debt, the resulting "negative goodwill" will be recognized as income in the accounting period in which the Merger closes.

24. Q. Please describe "push-down" accounting and its relevance to this Merger.

A. Under push-down accounting, Exelon, in its consolidated financial reporting, will be required to adjust the recorded amounts of the assets and liabilities of PHI and each of its subsidiaries to fair value as of the acquisition date. While the U.S. Securities and Exchange Commission ("SEC") generally prefers that such asset and liability adjustments also be reflected on the separate financial statements of each of the acquired company's subsidiaries (referred to as "push down" purchase accounting), such treatment is not always required by the

SEC when an acquired company's subsidiary has significant amounts of public debt or preferred stock securities outstanding.

Here, Exelon currently anticipates that no adjustments will be made to the amounts of assets and liabilities recorded by Pepco in its stand-alone financial statements. Exelon employed this approach to the reporting of BGE's assets and liabilities in the Exelon-Constellation transaction, and it was approved by the SEC. Exelon intends to employ the same approach with Pepco and is seeking SEC approval of this accounting treatment.

25. Q. Will Exelon's application of purchase accounting result in the creation of any regulatory assets or liabilities on Pepco's financial statements or the allocation of any additional costs to Pepco?

A. No costs will be allocated to Pepco related to purchase accounting. As previously discussed, subject to SEC concurrence, Exelon does not currently intend to apply "push down" purchase accounting to Pepco. As such, Exelon expects that Pepco will continue to prepare its financial statements using historical book values, with no adjustments for any new purchase-related regulatory assets or liabilities on their respective books and no additional allocation of costs or credits pursuant to purchase accounting.

26. Q. Will the accumulated deferred income taxes and accumulated deferred investment tax credits on Pepco's books be affected by the Merger?

A. No. The tax basis and book basis of Pepco's assets will be unchanged on the date that the Merger closes from what they were immediately preceding the closing, assuming no "push down" purchase accounting is required. Thus, Exelon does not anticipate any impact on accumulated deferred income taxes, accumulated deferred investment tax credits or the expected utilization of net operating loss carryforwards.

27. Q. Will the Merger affect the PHI money pool?

A. Yes. Currently, Pepco and Delmarva are eligible to fully participate in (i.e. invest in and borrow from) a money pool with one another and their non-utility affiliates; ACE, in contrast, is only permitted to borrow from the money pool. Following the Merger, there will not be any non-utility operating entities within the PHI portion of the combined holding company structure, and the money pool, therefore, will only have the three utility participants (plus PHI and the PHI Service Company, which will only be lenders to the money pool and will facilitate pool transactions).

Given the change in nature of the money pool, Exelon and PHI believe it would be appropriate for ACE to become a full participant in the money pool following the Merger. The three PHI utilities would only participate to the extent they can obtain a more favorable investment or borrowing rate from the money pool than available in the public market. For at least five years following completion of the Merger, no entities other than the PHI utilities (plus PHI and PHI Services Company) will participate in the PHI utilities' money pool, the PHI utilities will not participate in the money pool operated by Exelon, and there will be no commingling of funds with Exelon.

VI. THE MERGER INTEGRATION PROCESS

28. Q. Please provide an overview of the planned merger integration process.

A. Exelon and the PHI utilities have assembled a group of officers, senior managers, and other employees to plan, execute, and coordinate the business integration of the combined companies. Our goal is to ensure execution of integration plans so that upon closing the Merger partners are combined into a unified organization that operates effectively and efficiently, is well managed and is able to realize the goals and objectives established for the post-Merger operation of Pepco and the other PHI utilities.

29. Q. Please describe the integration process in more detail

A. In order to accomplish this goal, we will use an approach to merger integration developed by Exelon which consists of five distinct phases:

1. **Framework Development –** Establishment of an appropriate foundation for the merger integration process, including formation of "business area teams" ("BATs") and decision-making and issue-resolution processes. A BAT is created for each business area that may be affected by the Merger and its membership includes employees of each company with responsibility for the affected area. The BATs are responsible for developing and executing detailed functional plans so that the combined organization is fully operational upon consummation of the Merger, as well as developing initiatives to achieve synergy targets;

2. **Analysis –** Assessment of the current state of both companies, with an understanding of differences that need to be aligned for "Day 1" (the day on which the companies are merged) and for the long-term realization of savings and synergy opportunities;

3. **Design –** Development of a high-level description of the proposed "end state" for the merged companies, including updating of organizational structures and policies;

4. **Implementation Planning –** Development of an implementation plan to achieve the "end state," with a detailed schedule for completion; and final "Day 1" plans.

5. **Implementation –** During implementation, business areas execute the developed plans. Key activities include transitioning work from the integration teams to the "go forward" management and complying with all merger commitments, so that on "Day 1" the companies can operate as an integrated enterprise.

As Chief Integration Officer, I work with the PHI Chief Integration Officer to lead an extensive integration management structure to plan and guide the integration effort. Given the nature of the integration requirements, other executives from Exelon and PHI are also engaged with this effort to provide insights into current operations.

Additionally, we have developed a Project Management Office ("PMO") to oversee and coordinate all activities related to the planning and execution of the integration process. The PMO is supported by a "Core Team" – comprised of Exelon and PHI employees – from the Information Technology ("IT"), Finance, Human Resources, Supply, Communications and Operations areas of the companies. The Core Team provides integration guidance to all BATs and coordinates with the BATs to identify requirements and constraints (e.g., the impact of IT integration on specific business areas) and resolve cross-functional issues.

The structure I have described is illustrated in an organizational chart as JOINT APPLICANTS (F)-1, which shows how employees from various corporate organizations, operations, and support functions work cooperatively with each other as we work towards integrating the companies: The members of the Integration Office, the Core Teams, and the BATs will be selected based on their knowledge and experience relevant to each core area of the integration process.

30. Q. Are there particular factors that will guide the Joint Applicants' plans for the integration of the PHI utilities into the Exelon family of utilities?

A. Yes. As Mr. Crane has described, the Merger is intended to create the premier Mid-Atlantic energy distribution utility. As such, I expect the integration process to be particularly focused on ensuring that the PHI utilities are aligned with the existing family of Exelon utilities so that best practices for operational excellence can be easily shared.

As Messrs. Crane, Rigby, and O'Brien have also emphasized, Exelon's utility management model allows operating utilities to access the resources, expertise and financial strength of Exelon and all of its utilities while maintaining a strong local presence and remaining fully responsive to local conditions and priorities. As a result, the integration process will also be designed to reflect the fact that Pepco will remain a separate corporate entity, with a Board of Directors, and issue its own debt and preferred stock. The utility management model currently employed by PHI and the PHI utilities and the integration of PHI and the PHI utilities into Exelon's utility management model are described in the direct testimony of Mr. Rigby and Mr. O'Brien, respectively.

31. Q. Will the integration process take into account the Joint Applicants' Merger commitments?

A. Yes, it will. Exelon has been successful in complying with its current merger commitments, and our planned integration process for this Merger will include careful monitoring and compliance with the Merger commitments and the integration of those commitments into Merger implementation plans. By way of example, the integration process and plans will reflect a commitments to maintain PHI's and Pepco's corporate headquarters in the District of Columbia. These plans will also incorporate the commitments Mr. O'Brien has described with respect to employment levels and employee compensation and benefits.

32. Q. What is the current timeline for the integration process?

A. The five-phase integration process I have described is structured so that each phase builds upon the objectives and conclusions of the preceding phase. The companies have already begun the Framework Development phase, and I expect that Framework Development will be complete in July 2014 with formation of all of the necessary BATs. Based upon our work to date, we are focusing on a close in the second or third quarter of 2015 and a thus a "Day 1" for the combined companies in the second or third quarter of 2015.

While the companies will use that timeframe for Day 1 readiness and preparing for effective and efficient operation of the combined organization in the first year of operations, the integration process will continue for several years because the actual combination of business structures, systems and processes must "ramp up" on a carefully staged basis over time. As a consequence, the anticipated savings from the Merger will not be fully realized until several years after the Merger is consummated. To cite just one example, the integration of technology platforms will take place over several years in order to accommodate the priorities of the business and constraints on available resources.

VII. PROJECTED MERGER-RELATED SAVINGS

33. Q. Please describe the level of Merger-related savings that you expect to be achieved at the PHI utilities.

A. Exelon conducted an analysis, utilizing publicly available data, of the potential savings that can reasonably be realized by combining Exelon and PHI and the portion of such savings allocable to the PHI utilities. As shown in Table 1, below, positive Merger-related savings at the PHI utilities, net of the costs that will be incurred to achieve those savings, are projected to begin in the second year after the Merger and grow to approximately $43 million annually by the fifth year. The estimated savings for the PHI utilities, net of the costs to achieve the savings, will total $95 million over that five-year period, as shown below:

TABLE 1

($ Million)	Pre-Closing	Year 1	Year 2	Year 3	Year 4	Year 5	Total
PHI Utilities Synergies		18	25	35	39	43	160
Costs to Achieve	(11)	(49)	(5)	(0)	(0)	(0)	(65)
PHI Utilities Net Synergies	(11)	(31)	20	35	39	43	95

Additional details of the estimated savings and costs-to-achieve are provided in JOINT APPLICANTS (F)-2.

As Mr. Crane explains in his direct testimony, Exelon is proposing to fund a Customer Investment Fund of $100 million to provide an immediate tangible benefit to PHI customers from the Merger-related savings the PHI utilities are expected to achieve during the first five years following completion of the Merger. As the data in Table 1 show, the proposed Customer Investment Fund actually exceeds the estimated PHI utilities' Merger savings during that period. Additionally, Exelon and PHI are committing to flow through net Merger savings allocable to the PHI utilities in future rate proceedings. Consequently, if any PHI utility were to file a rate case utilizing a test year within that five-year post-Merger window, customers will benefit from receiving some portion of the net Merger savings twice – once through the Customer Investment Fund and a second time through lower post-Merger expenses reflected in the ratemaking process.

Of course, annual Merger savings (estimated to be $43 million as shown above) will continue beyond five years following the completion of the Merger. As a result, customers will realize additional benefits, in future rate cases, from avoided expenses that continue to accrue during those future periods beyond the $100 million tangible benefit the companies propose to provide immediately following the Merger. The Customer Investment Fund is not subject to downward adjustment if Exelon does not achieve the expected Merger-related savings attributable to the PHI utilities.

34. Q. How were these estimates of savings developed?

A. Exelon engaged the Boston Consulting Group ("BCG"), a global management consulting firm, to analyze the potential savings that could be realized through the Merger. BCG undertook this project in two phases.

First, BCG conducted an "outside-in" analysis of the PHI companies. In this phase, BCG collected publicly available information, such as PHI investor communications and documents filed with regulatory agencies (e.g., annual reports to the SEC and Federal Energy Regulatory Commission). BCG then estimated potential synergies and savings that could be achieved at the combined Exelon-PHI company based on information from other mergers of electric and gas utilities and additional data provided by Exelon regarding its operations. The additional data used in this "outside-in" analysis included information on synergies and savings achieved at BGE after Exelon's merger with Constellation Energy and the actual costs to achieve those synergies and savings, but did not include any non-public PHI information.

Second, BCG conducted a "bottom-up" analysis. For this analysis, BCG obtained information from PHI about how various corporate, support and utility functions are performed at the PHI companies and the levels of expenditures and full-time equivalent employees for each function. Using this information, BCG "mapped" the functions performed at the PHI companies to the equivalent functions at Exelon and the Exelon utilities. Based on information Exelon provided about how these functions would likely be staffed and performed for the combined enterprise, BCG calculated expected Merger savings in each functional area and estimated the cost and time necessary to achieve those savings.

Each approach has strengths and limitations, which are generally associated with the type of data available for each. However, together they serve as a useful "check" on each other to validate projected savings and the associated costs to achieve those savings.

From the "outside-in" analysis, BCG concluded that, at the end of the fifth year following the Merger, the combination of Exelon and the PHI companies (including utility and non-utility operations) would be expected to achieve annual operational expense savings of between $109 million and $151 million. The second "bottom-up" analysis, using more detailed data from the PHI utilities, produced a lower estimate of $96 million in annual savings. In both cases, the estimated annual savings reflect synergies across the entire post-merger company (*i.e.* all Exelon and PHI utilities and non-utility businesses).

In light of these two estimates and the way each was derived, BCG recommended – and Exelon adopted – a projected level of annual savings from the Merger for the entire company of $130 million beginning at the end of the fifth year following the Merger. Although the $130 million is greater than the "bottom-up" analysis, we believe that this estimate is justified because the "bottom-up" analysis does not capture all of the savings that could be achieved, such as additional performance improvements at the PHI utilities and other opportunities that may be found through the integration process.

Once the estimated steady-state annual savings target of $130 million had been established, BCG was able to project the savings and costs to achieve that would be expected at the PHI utilities in each of the first five years following completion of the Merger. After the Merger was announced, Exelon requested that BCG prepare a revised estimate of synergies and savings in light of Exelon's Merger commitments (including commitments relating to PHI employees and facilities). BCG's examination projected net savings of $95 million at the PHI utilities in the first five years of the Merger, as shown in Table 1. JOINT APPLICANTS (F)-2 is a copy of BCG's revised estimate of synergies and savings.

35. Q. Please explain the nature of the synergies and savings that the Joint Applicants expect to achieve.

A. The Merger of Exelon and PHI will create the opportunity to realize savings by eliminating overlap and duplication in company-wide operations, realizing economies of scale and streamlining corporate functions. For example:

- Information Technology: Significant economies of scale are expected to be achieved through integration and select migration of technology environments, with additional savings from eliminating duplicative investments in technology and reducing expenditures on a combined company basis for data centers, network infrastructure, applications, and technology support.
- Corporate Functions and Support Services: Certain corporate functions required by two distinct companies – such as investor relations and employee benefits administration – become duplicative when those functions are combined. By eliminating this functional duplication and streamlining corporate services, the Merger will result in lower overhead expense and more efficient use of resources to meet the needs of the combined companies and, in that way, create substantial savings over time.

While most of the projected savings are associated with eliminating duplication and achieving economies of scale in corporate functions, Exelon also expects to achieve some additional savings through the application of best practices in transmission and distribution functions and customer operations and in supply procurement.

The savings Exelon has projected are based entirely on operational expense savings. Savings in future capital expenditures arising from the Merger at Pepco and the other PHI utilities are expected to be reinvested in other needed capital projects.

36. Q. Mr. Khouzami, what are the "costs to achieve" the savings you have described?

A. Costs to achieve are actual expenditures that will be incurred as a result of the Merger, and include expenses in such areas as employee compensation, communications, technology migration, financing, accounting, and many others. As shown in the table of estimated merger savings I have provided, we expect the costs-to-achieve to be incurred in the early years after the Merger. Because the Joint Applicants have committed that Pepco and the other PHI utilities will not seek recovery in rates of transaction costs incurred in connection with consummating the Merger, those costs are not considered to be "costs to achieve" in estimating savings from the Merger.

37. Q. Mr. Khouzami, how were the estimated savings and costs to achieve at the combined company allocated to the PHI utilities?

A. Because certain functions and resources – such as computer systems and human resource management – at both Exelon and PHI are shared among both regulated and non-regulated or competitive activities, the first step in the allocation process is to determine whether an estimated savings or costs to achieve category could be directly assigned to the regulated or non-regulated business segments based on the nature of the savings or costs to achieve category.

For those savings or costs to achieve that can be directly assigned to the PHI utilities (for example, supply chain benefits within the regional transmission and distribution businesses), the net savings assigned to PHI were allocated among the PHI utilities based on a Modified Massachusetts Formula ("MMF") calculation.[5]

For those savings that could not be directly assigned to the regulated or non-regulated or competitive business segments (for example, consolidation of corporate support functions supporting both the regulated and competitive business segments), the PHI utilities were allocated a portion of the savings among all of the combined company subsidiaries (regulated and non-regulated) based on the MMF calculation. The results of this allocation process are shown in JOINT APPLICANTS (F)-2

38. Q. Mr. Khouzami in light of the fact that the proposed Customer Investment Fund actually exceeds the estimated PHI utilities' Merger savings will it be necessary to monitor the costs and savings of the Merger on a going forward basis?

~~A.~~ No. As Mr. Crane explains in his direct testimony, Exelon is proposing a Customer Investment Fund of $100 million to provide an immediate tangible benefit to PHI customers from the Merger-related savings the PHI utilities are expected to achieve during the first five years following completion of the Merger. As a result, Pepco's customers in the District of Columbia will experience direct and traceable financial benefits resulting from the merger. Additionally, Exelon and PHI are committing to flow through net Merger savings

[5] The MMF calculation reflects a three-part formula consisting of revenues, assets and direct labor.

allocable to the PHI utilities in future rate proceedings. Consequently, if any PHI utility were to file a base rate case within that five-year post-Merger window, customers will benefit from receiving some portion of the net Merger savings twice – once through the Customer Investment Fund and a second time through lower post-Merger expenses reflected in the ratemaking process. The added savings will be reflected in lower test-period costs and expenses. Thus, there is no reason to track merger costs and savings on a going forward basis.

VIII. RELIABILITY COMMITMENTS AND FINANCIAL PENALTIES

39. Q. Mr. Khouzami, Mr. Crane has stated that Exelon will back-up its reliability commitments at Pepco with a performance guaranty that will trigger a financial penalty if reliability performance-improvement goals are not achieved. Can you please explain the performance guaranty and financial penalty proposed by Exelon?

A. Yes. Exelon is providing a performance guaranty that Pepco will achieve a level of improvement by 2020 in two key reliability metrics: its System Average Interruption Frequency Index ("SAIFI") and its System Average Interruption Duration Index ("SAIDI"). As Mr. Alden explains, Exelon is committing that Pepco will achieve a SAIFI of 0.54 and SAIDI of 107 based on a three-year average calculation in 2021 for the 2018-2020 period. The calculation of SAIFI and SAIDI will be performed using the same procedures as the Commission now uses in calculating Pepco's reliability performance. Exelon is proposing to use a three-year average to avoid the effects of weather variability in a single measurement year.

If this level of reliability improvement is not achieved, the return on equity ("ROE") to which Pepco would otherwise be entitled in its next electric distribution rate case filed after January 1, 2021, will be reduced by twenty-five basis points. This financial penalty would be in addition to any other financial penalty the Commission might impose for if Pepco failed to meet its Commission-set reliability requirements in 2020.

40. Q. How long does Exelon propose that the ROE penalty, if imposed, would remain in place?

A. The ROE reduction would apply throughout the period that the rates established by that rate proceeding are in effect. Pepco would be required to initiate a new rate proceeding and obtain an order from the Commission approving new rates in order to end the ROE penalty.

41. Q. Under Exelon's proposal would Pepco be penalized if it meets one reliability commitment but not both?

A. Yes, because the two metrics measure different components of reliability: SAIFI is a measure of the number of sustained customer interruptions, while SAIDI is a measure of the duration of sustained customer outages. Under Exelon's proposal, if Pepco achieves its performance commitment on one metric but not the other metric, the penalty will still be imposed but it would be reduced by half (i.e., 12.5 basis points instead of 25 basis points).

IX. AFFILIATED INTEREST AGREEMENT

42. Q. Please explain the affiliated interest agreement that Pepco will enter into upon the consummation of the Merger.

A. Pepco will participate in Exelon's existing General Services Agreement ("GSA"). A copy of the GSA is attached as part of JOINT APPLICANTS (F)-3. The GSA is an agreement under which Exelon Business Service Company (the "EBSC") provides a variety of services to Exelon utilities and other Exelon subsidiaries. Upon approval and close of the Merger, Pepco will become a party to the GSA and be able to receive services from the EBSC. As a party to the GSA, Pepco will also be able to receive services from (and provide services to) other Exelon utilities, including services relating to storm management.

43. Q. What is the EBSC?

A. Like many other energy holding-company systems, including PHI, Exelon created a service company, the Exelon Business Services Company, or EBSC, to house specific support functions that it believed could be staffed more efficiently and economically on a centralized basis. The EBSC is designed to provide a range of what would typically be regarded as in-house services in the case of a stand-alone utility. In broad terms, those services fall into the following categories: information technology; supply; finance; human resources; government and environmental affairs and public policy; general counsel/legal; corporate secretary; strategy; and communications. The EBSC offers its services to the members of the Exelon family of companies, including PECO, ComEd and BGE, and enables those companies to realize economies of scale and scope that could be very difficult to achieve on an individual-company basis.

44. Q. Will Pepco be required to use the EBSC?

A. No. Under the terms of the GSA, each utility has the discretion to determine whether and to what extent it will utilize the EBSC's services. The only exception to this general policy falls in the area of "corporate governance," where the EBSC provides services to each party to the GSA.

45. Q. How will Pepco be charged for services provided by EBSC?

A. The GSA provides that the services furnished by the EBSC to Pepco will be billed at the EBSC's cost, and direct charges of those costs will be made wherever possible. If a cost cannot be assigned directly to a utility, it is allocated on the basis of the allocation factors/methodologies identified in the EBSC Associate Transaction Procedures Manual ("ATPM"), which is attached as JOINT APPLICANTS (F)-3. The ATPM will be filed with the Commission within thirty days after the effective date of Pepco's first use of EBSC services. After the Merger, the Commission will have the same access to EBSC's books and records and the same transparency into EBSC as it has with PHI Service Company.

46. Q. Will the PHI Service Company be maintained after the Merger?

A. A. The PHI Service Company will remain in place for an undetermined period of time during post-merger integration. As integration proceeds and systems and functions are combined in phases, Pepco may receive different services from the EBSC and the PHI Service Company until all shared corporate support functions are consolidated under EBSC.

X. CONCLUSION

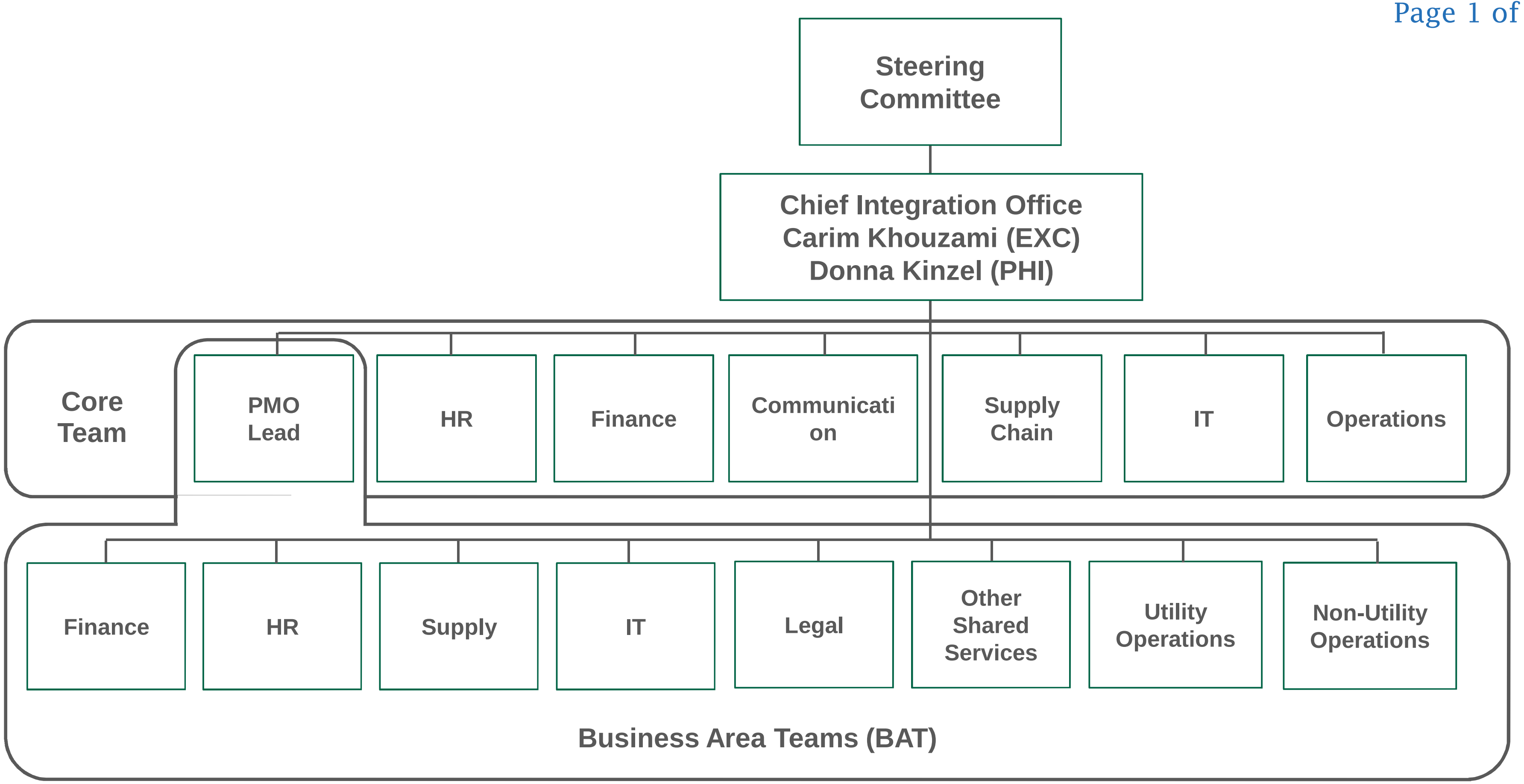
47. Q. Does this conclude your direct testimony?

A. Yes, it does.

C.V. Khouzami Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _____ (F)-1

PMO Organization



C.V. Khouzami Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _____ (F)-2

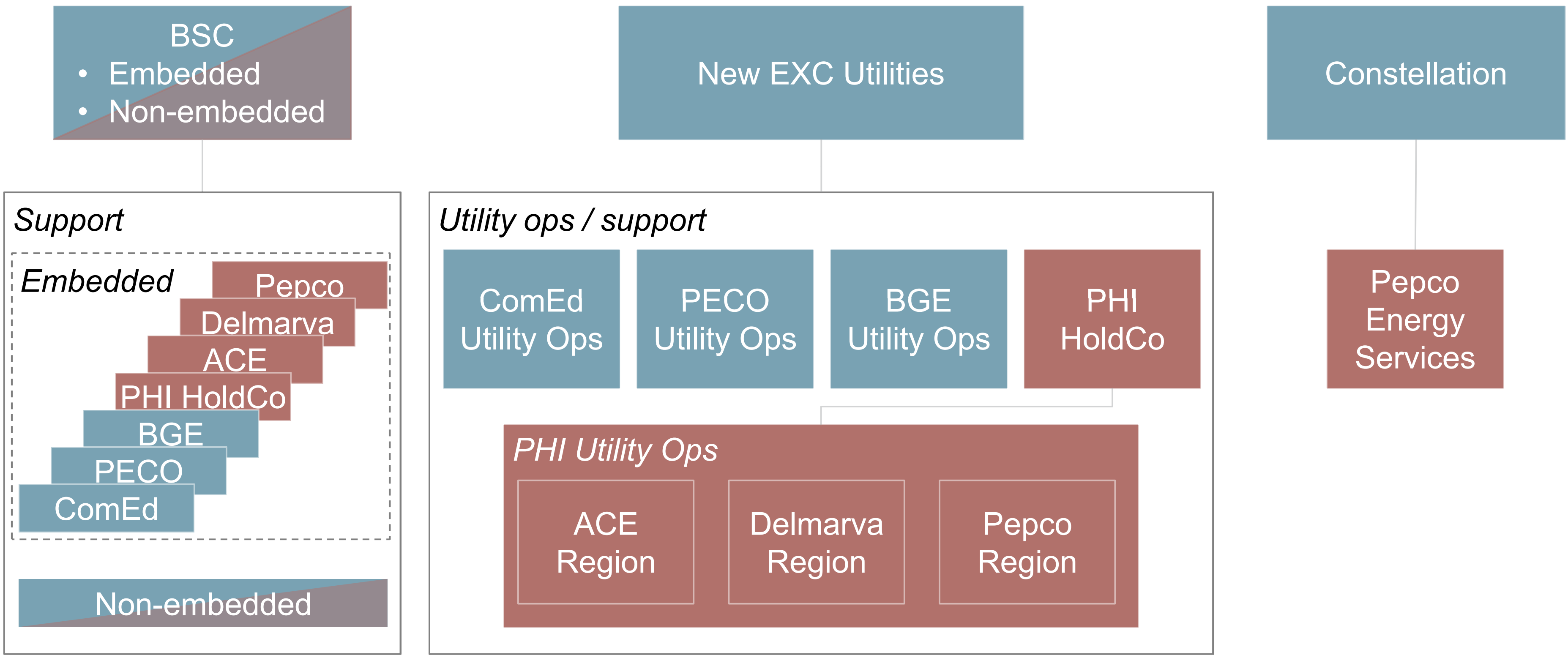
Net synergy estimates

June 2014

Exelon.

Target operating model: Incorporate PHI as fourth utility

Non-embedded BSC to be shared, PES to be incorporated into Constellation



Note: "Embedded" represents employees and associated costs (including all departmental costs) that are part of an actual Operating Company (yet role up to BSC); "Non-embedded" represents employees and associated costs that are all shared service company costs

Synergy estimate: Approach overview

Outside-in and bottom-up estimates

Outside-in: Based on publicly available data[1] (FERC, 10-K, PHI external communications)

Scale[2] applied to utility ops/support[3] and BSC

Scale[2] applied to each function

Synergy estimate

Bottom-up: Based on PHI data from due diligence

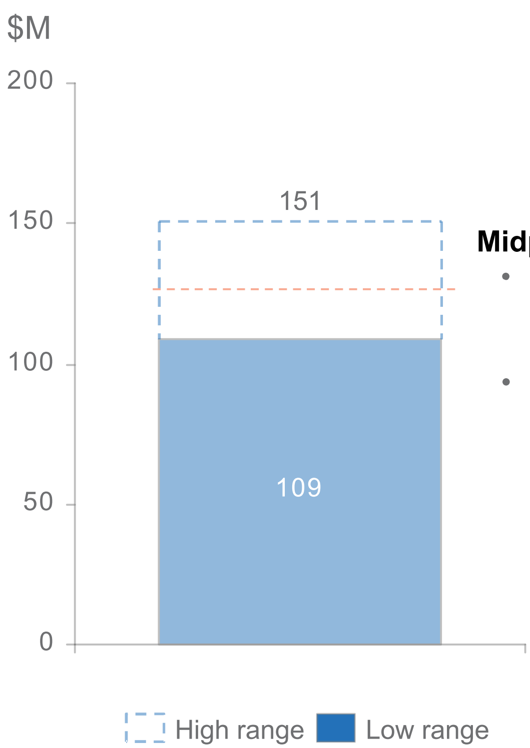
Bottom-up: Performance improvement and scale[3,4] applied to each subfunction

1. No internal information was provided by PHI 2. Based on BCG synergy database for power & gas 3. No labor synergies included for utility ops 4. Estimated by working team without any synergy target

Overview of O&M synergy estimates for EXC and PHI

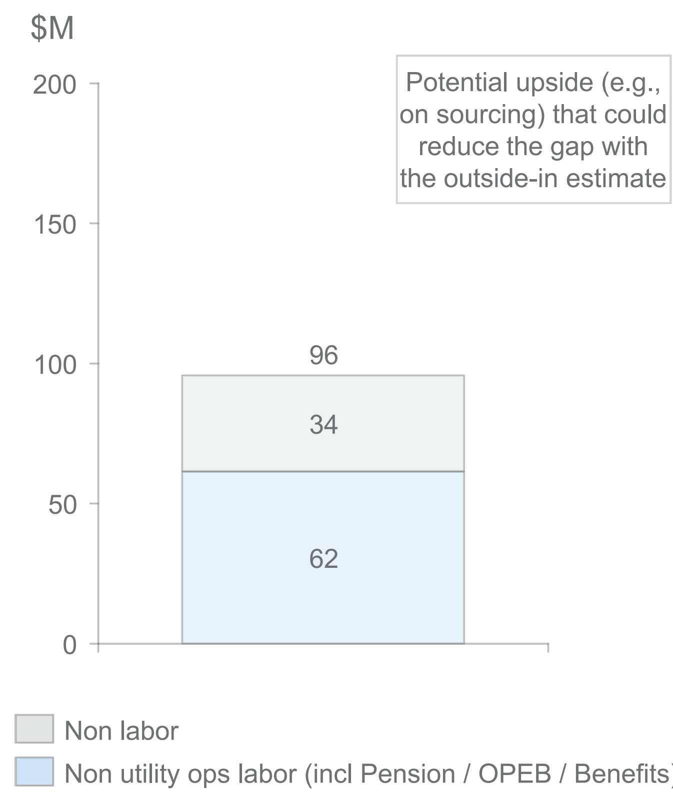
$130M outside-in vs. $96M bottom-up

"Outside-in" Y5 steady state synergy estimate: $130M



Midpoint: $130M
- Non utility ops labor (incl Pension/ OPEB): $*57M*
- Non-labor: $*73M*

"Bottom-up" Y5 steady state synergy estimate: $96M

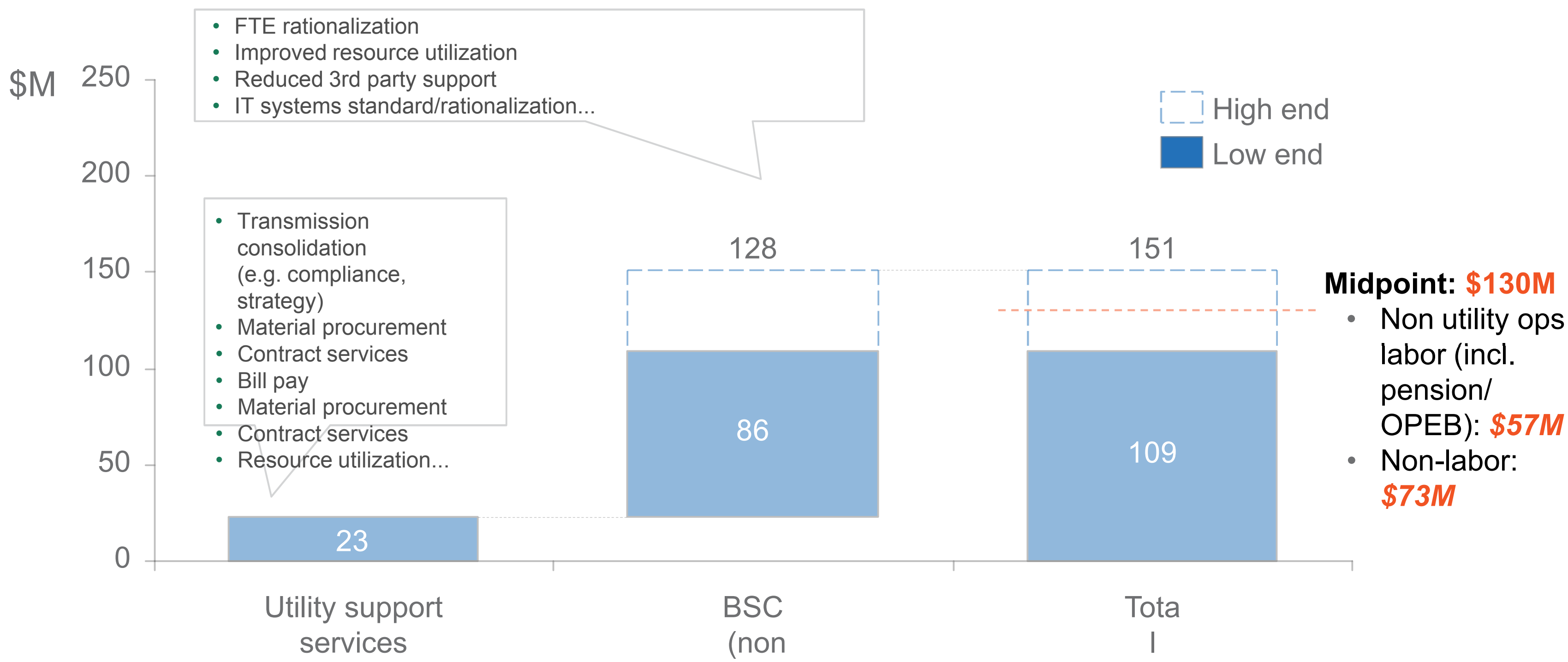


Recommend targeting $130M annual run rate synergy to capture unidentified upside to bottom-up estimate

Outside-in estimate of O&M synergies: ~$130M /yr in year 5

Estimate ranges from $109M to $151M

O&M synergy estimate for EXC and PHI – Year 5 steady state synergies



	Utility support services	BSC (non embedded)	Total
Combined EXC/PHI O&M baseline	$2,598M[1]	$1052M	$3650M
Synergy (% EXC /PHI O&M baseline)	~1%	8-12%	3-4%
PHI O&M baseline	$488M[1]	$213M	$701M
Synergy (% PHI baseline)	5%	40-60%	16-22%

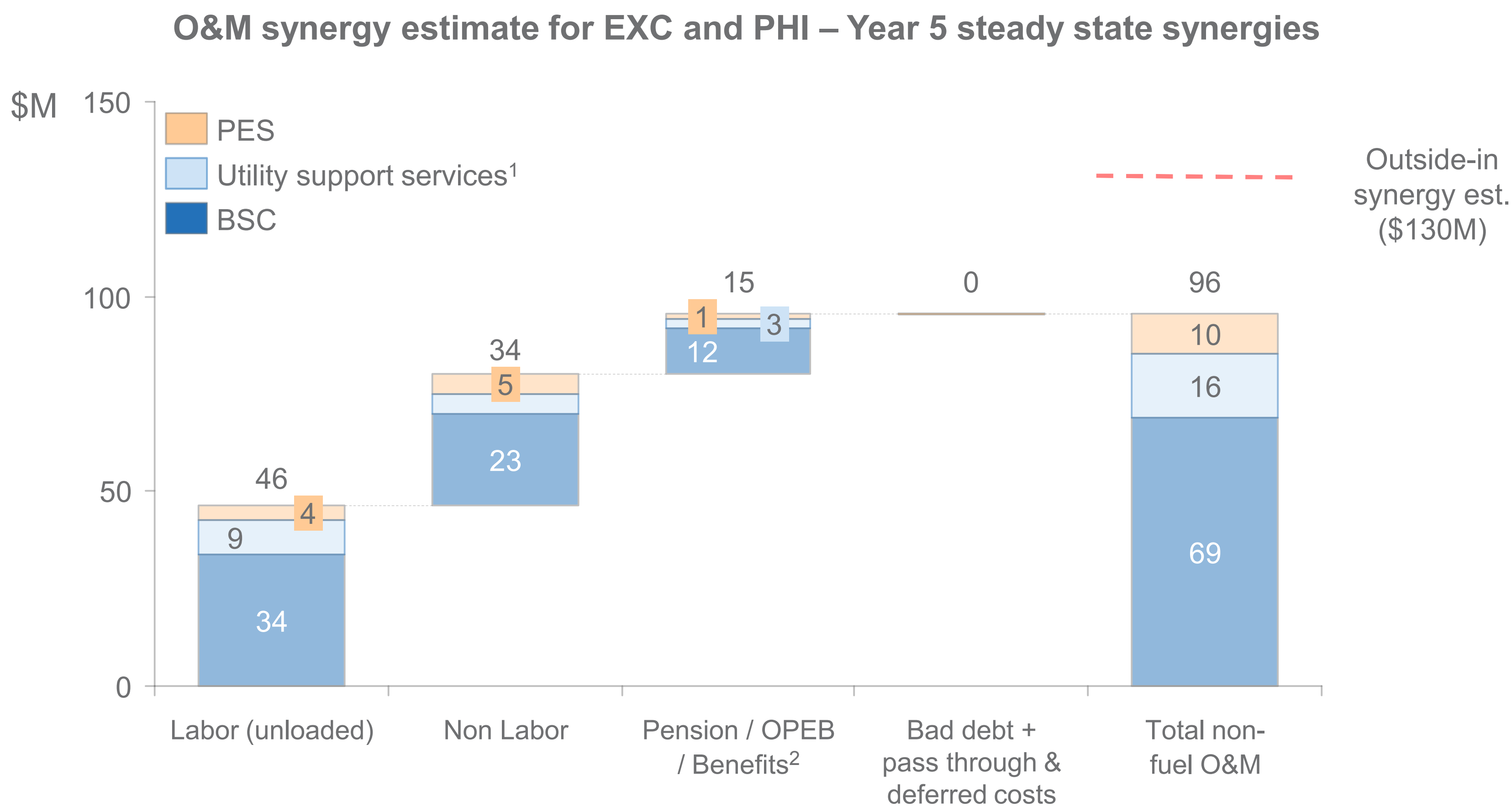
Phase 1 baseline

1. Baseline includes utility ops

Exelon.

Bottom-up estimate of O&M synergies: ~$96M / yr in year 5

Breakdown by cost category



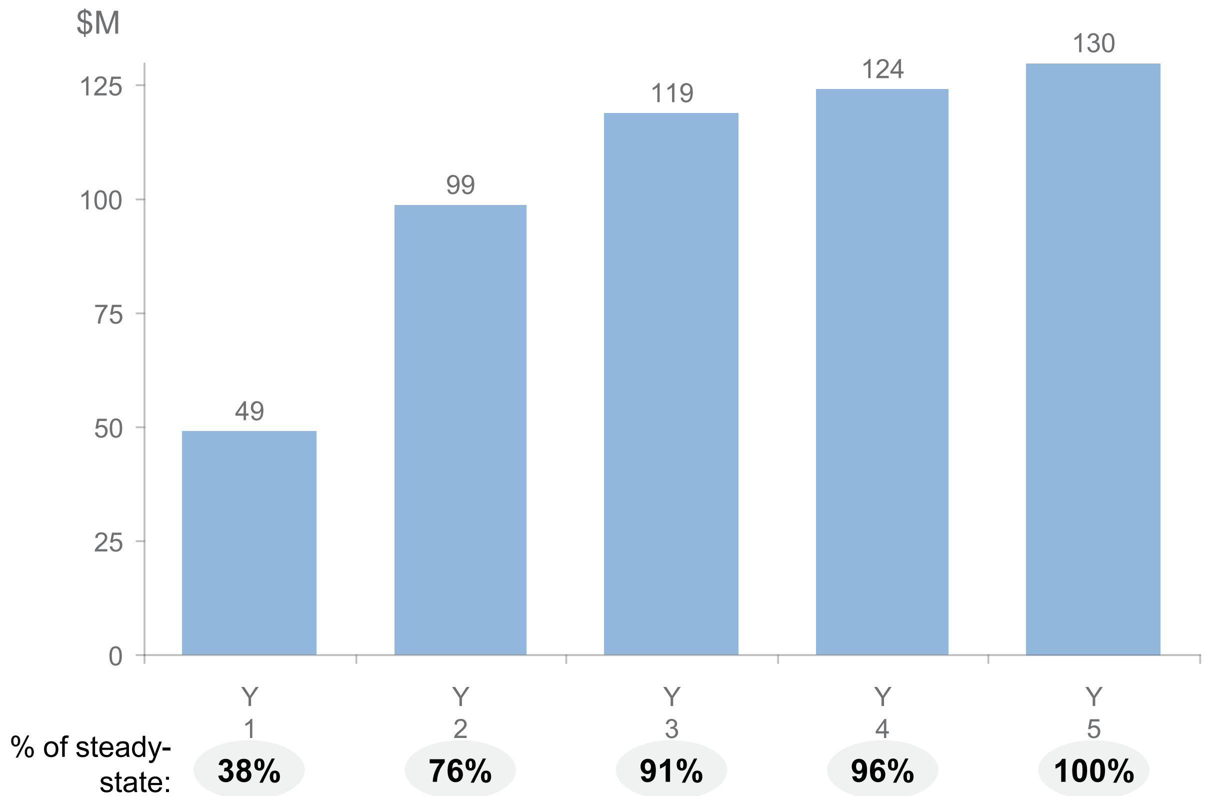
	Labor (unloaded)	Non Labor	Pension / OPEB / Benefits	Bad debt + pass through & deferred costs	Total non-fuel O&M
PHI O&M baseline ($M)	323	561	131	32 + 122	1,169
Synergy (% PHI baseline)	14%	6%	13%	0%	8%

1. Includes sourcing synergies 2. Pension / OPEB / Benefits synergy assumed to be 30% of unloaded labor benefit + SERP

Exelon.

Glidepath of O&M synergies for EXC and PHI

Estimated synergy glidepath realization



Assumptions / data sources

BSC labor synergies interdependent with IT integration

- Year 1 FTE reduction: ~30% of target
- Year 2 FTE reduction : ~80% of target
- Years 3-5 FTE reduction: 100% of target

Utility support performance improvement[1] assumed to begin in Year 3 (2-yr commitment not to impact utility)

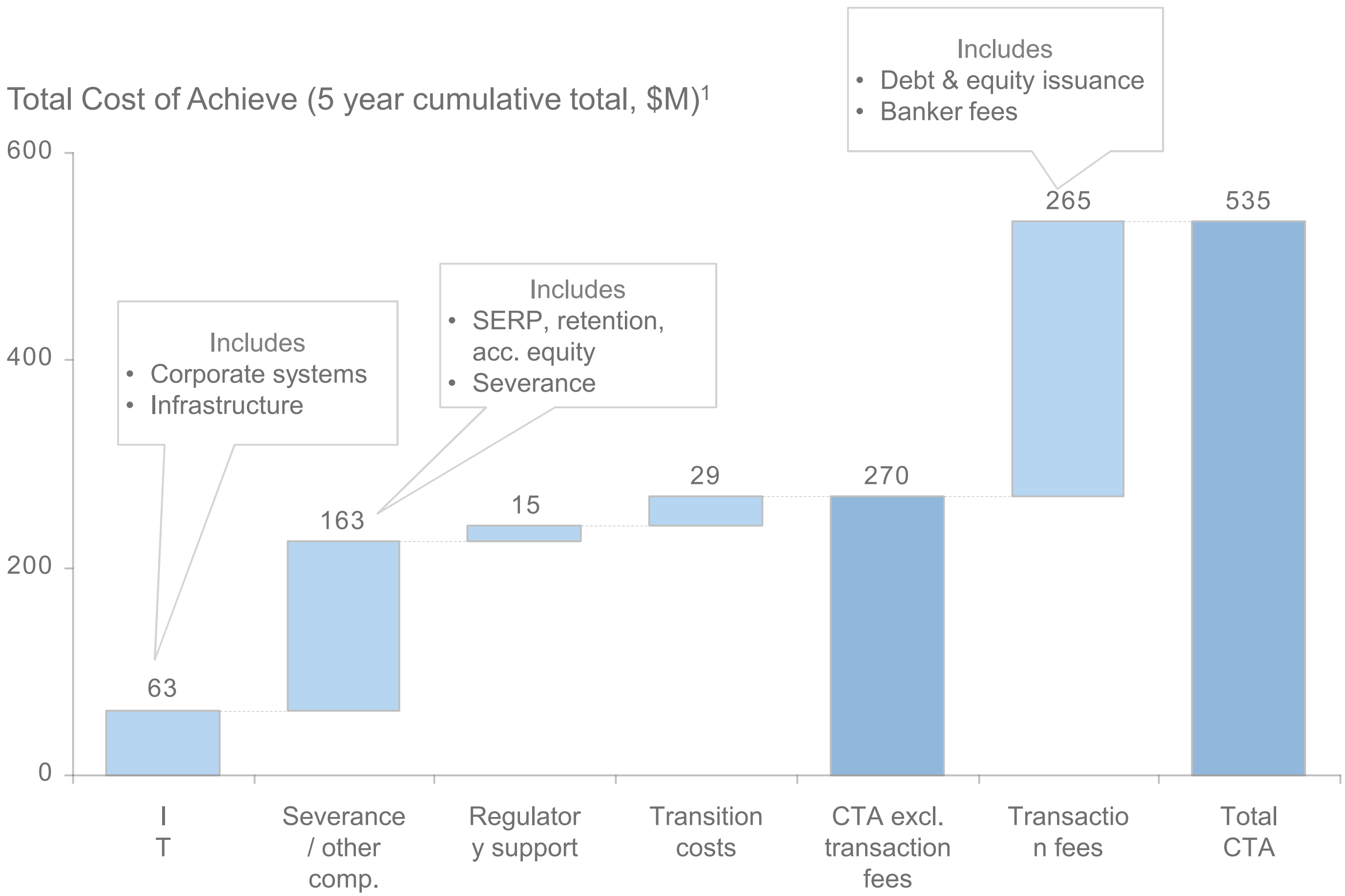
- Year 1 FTE reduction[1]: 0% of target
- Year 2 FTE reduction[1]: 0% of target
- Year 3 FTE reduction[1]: ~50% of target
- Year 4 FTE reduction[1]: ~75% of target
- Year 5 FTE reduction[1]: 100% of target

Assumes no reduction of utility ops FTEs

Non-labor synergies (primarily IT) driven by system decommissioning and not realized until Year 2

1. FTE reductions assumed on utility support (e.g., engineering)
Source: Glide path based on bottom-up glide path, grossed up to reach $130M outside-in target synergy

Preliminary estimate of transaction Cost To Achieve



1. Includes O&M (~94%) and Capex. (~6%)

Note: Estimates assume no attrition; Transaction costs estimated by EXC Corporate development

Total of ~$250M in cumulative net synergy through Y5

Disaggregated view

Breakdown of Total Cumulative 5Y Savings (Synergies + CTA) by organization

5-year Cumulative Net Synergy (Synergies – CTA[1])
$522 - $270M = $252M

PECO ~$16M

BGE ~$26M

ComEd ~$32M

PHI utility ~$95M

- Pepco MD ~$29M
- Pepco DC ~$15M
- Delmarva DE ~$18M
- Delmarva MD ~$9M
- ACE ~$23M

Combined non-utility ~$84M

Total Regulated net synergy ~$168M

~67%

Total Non-regulated net synergy ~$84M

~33%

Regulated utilities | *Non-regulated*

1. Excluding transaction costs
Note: MMF calculated using Exelon's methodology (Gross revenue, Assets, Direct labor); Pepco and Delmarva synergies split across jurisdictions using ratio of customer counts
Source: FERC Form 1,2,60; Project PHI synergy estimates, BCG analysis

Appendix

Net synergies by PHI entity

($M)	Pre-close	Y1	Y2	Y3	Y4	Y5	Total
Pepco							
Synergies		8	12	16	18	20	74
CTA	(5)	(23)	(2)	0	0	0	(30)
Net synergies	(5)	(14)	9	16	18	20	44
DPL							
Synergies		5	7	10	11	12	46
CTA	(3)	(14)	(1)	0	0	0	(19)
Net synergies	(3)	(9)	6	10	11	12	27
ACE							
Synergies		4	6	9	10	11	40
CTA	(3)	(12)	(1)	0	0	0	(16)
Net synergies	(3)	(8)	5	9	10	11	23
PHI utilities							
Synergies		18	25	35	39	43	160
CTA	(11)	(49)	(5)	0	0	0	(65)
Net synergies	(11)	(31)	20	35	39	43	95
Cumulative	(11)	(42)	(22)	13	52	95	

Note: Pepco and Delmarva synergies split across jurisdictions using ratio of customer counts

Net synergies by PHI entity and jurisdiction

($M)	Pre-close	Y1	Y2	Y3	Y4	Y5	Total
Pepco MD							
Synergies	0	6	8	11	12	13	50
CTA	(3)	(15)	(2)	0	0	0	(20)
Net synergies	(3)	(10)	6	11	12	13	29
Pepco DC							
Synergies	0	3	4	5	6	7	24
CTA	(2)	(7)	(1)	0	0	0	(10)
Net synergies	(2)	(5)	3	5	6	7	14
Delmarva DE							
Synergies	0	4	5	7	8	8	32
CTA	(2)	(10)	(1)	0	0	0	(13)
Net synergies	(2)	(6)	4	7	8	8	19
Delmarva MD							
Synergies	0	2	2	3	4	4	15
CTA	(1)	(4)	0	0	0	0	(6)
Net synergies	(1)	(3)	2	3	4	4	9
ACE							
Synergies	0	4	6	9	10	11	40
CTA	(3)	(12)	(1)	0	0	0	(16)
Net synergies	(3)	(8)	5	9	10	11	23
PHI utilities							
Synergies		18	25	35	39	43	160
CTA	(11)	(49)	(5)	0	0	0	(65)
Net synergies	(11)	(31)	20	35	39	43	95
Cumulative	(11)	(42)	(22)	13	52	95	

Note: Pepco and Delmarva synergies split across jurisdictions using ratio of customer counts

Exelon.

C.V. Khouzami Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _____ (F)-3

EXELON BUSINESS SERVICES COMPANY

ASSOCIATE TRANSACTION PROCEDURES MANUAL

January 2014

Introduction

Exelon Business Services Company, LLC (BSC or Services Company) provides a variety of administrative, management and support services to Exelon Corporation and other Exelon system companies and business units (Client Companies). BSC is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Holding Company Act of 2005 (PUHCA). In addition, each of the individual state regulated public utility companies have additional requirements related to associate transactions. Where applicable, these requirements have been incorporated into these Policies and Procedures.

Service Agreements and Work Orders

BSC has entered into a General Services Agreement or Service Agreement with Client Companies that is substantially similar to the General Services Agreement (GSA) attached hereto as Exhibit A. The Service Agreement sets forth in general terms the services to be performed by BSC directly or indirectly for Client Companies. BSC and each Client Company will prepare Work Orders, in the form of Service Level Arrangements (SLA), to specify the services to be performed by BSC for a Client Company. A sample SLA is attached hereto as Exhibit B. Additional documentation of work to be performed pursuant to SLAs may be used by the parties.

The purpose of the SLA is to establish service expectations between BSC and each Client Company. Each SLA will be reviewed and agreed upon on an as needed basis by authorized representatives of BSC and each Client Company. In conjunction with this review of SLAs, the allocation methods and ratios presented in Service Agreement Schedules 1 and 2, attached to the GSA, shall be reviewed and agreed upon by the parties.

An SLA typically contains the following elements:

1. Scope of Services

2. Service Level Expectations

3. Unit Cost Expectations

4. Performance Measures

5. Billing Process

6. Major Contingencies

Each SLA is approved by the individual(s) authorized to represent BSC and the Client Company related to the services to be provided.

BSC currently has three distinct processes related to SLAs.

1. The SLA process starts with the BSC Service Providers and the Client Companies representatives meeting to agree upon services to be provided over a future period of time, generally one to three years in duration. As BSC has been in operation for over ten years, most services have been defined and have been agreed to by the parties, and have been delivered efficiently and consistently to the Client Companies for a period of time. New service areas and services may be added in the future, or may be removed from the BSC services offerings. The SLA meetings focus on changes to service offerings and on refining the expected quantities to be consumed, as well as on improvements in providing the services or changes in the operational requirements around providing the services, including benchmarking and performance metrics, definition of responsibilities and other provisions between Service Providers and customer. The Service Providers are responsible for the over-all content in each SLA. Portions of the SLA template are reviewed by Legal. Early in the SLA process, the Legal review concentrates on the purpose, scope, governing agreement and certain terms and conditions. The Accounting review of SLA drafts takes place near the end of the process and concentrates on the billing approach and pricing table sections of the SLAs for compliance to the GSA and other PUHCA 2005 requirements. The billing / pricing sections of the SLAs are broken down into billing components for entry into the BSC Billing Systems. BSC Finance will check completed SLAs to make sure that changes are not made after Legal and Accounting review, or if such changes have been made, will obtain Legal and/or Accounting review of the changes. BSC Finance shall retain documentation evidencing the required SLA reviews in accordance with the record retention requirements. BSC works with the accounting and finance departments in the Client Companies to set-up the code block that the customer wants to be charged for the various services, and the level (company level, intermediate level, or department level) at which they wish to be billed. BSC Accounting works with BSC Finance to set up the appropriate accounting – cost capture pools on BSC's books. For most customers, the BSC Billing Systems journalize the actual monthly charges on the customer's books during the financial close.

2. The second process relates to change orders and other emergent work that appear after budgets have been locked down and the actual year has begun. Similar to the SLA process, BSC Accounting is involved to review any change orders for GSA and PUHCA compliance, and work with the customers' accounting departments to set-up and bill each item appropriately.

3. The third process relates to acquisitions or other new potential business for BSC. The BSC Service Providers interface with the M&A Team. The BSC support services costs are developed and include one-time and on-going support costs. Emergent work projects are set-up to collect one-time charges of adding the acquisition into BSC established services. BSC may prepare a proposal capturing integrated support service scope, schedule, budget, and assumptions. Linkage to an existing customer SLA is generally preferred, otherwise a new SLA may need to be created. For new SLA work, general terms and conditions are reviewed and signed by the controlling customer authorizing the work to proceed. BSC Finance and BSC Accounting gets involved in similar roles as mentioned above for the other processes.

Accounting Procedures

BSC will maintain processes which allow it to accumulate costs in Cost Centers and cost pools. Where possible, these costs will be charged out to Client Companies using direct charging methodologies, including time and materials and unit price (standard rate) basis. Cost Centers and cost pools collect resource costs for services and activities described in the SLA. This process supports the philosophy of billing costs to the Client Company on an appropriate basis. BSC will use this process to maintain accounting systems to record all of its costs.

Costs will be billed to Client Companies as work is performed and costs are incurred. When a service requested by a Client Company has not been previously specified, a new SLA may be created or the existing one revised. BSC Accounting is responsible for ensuring that all of the billing methodologies are consistent with the GSA.

Direct Costs are defined as those that can be identified as applicable to services performed for a single Client Company or group of Client Companies. Direct costs include the fully distributed cost of providing a particular service. The fully distributed costs include labor costs, labor related costs (such as pensions and benefit costs, and facility costs), IT costs, outside services where applicable, back office support costs of running BSC, and other non-labor costs such as materials and supplies. Direct Costs will be charged to the Client Company or Companies responsible for the activity.

BSC will use direct charging (e.g., standard costing or unit prices and/or time and materials) and cost allocations to bill Client Companies. Under a standard costing methodology, as product or service units are used by the Client Companies, the services are directly billed to Client Companies at standard rates. Standard rates are fully cost burdened billing unit rates used by a specific department for a specified service. These rates are established for a number of services offered by the Services Company including invoice processing cost per invoice, mainframe computing cost per CPU minute, and IT desktop support cost per desktop computer. In general, these standard rates are calculated by estimating the fully distributed cost of providing the service for the year divided by the expected number of units (selected as the unit of measurement) to be consumed by all associated customers.

Residual amounts or costs that cannot be directly billed using reasonable measures will remain in the Cost Center to be allocated to Client Companies on an appropriate basis.

Indirect Costs include those costs of a general nature such as general services, and other support costs which cannot be specifically identified to a specific client company or smaller group of companies or to a specific service and therefore must be allocated. An example of Indirect Costs includes most corporate governance services that benefit all companies, which consists of, for example, functions such as accounting, finance, executive, strategic planning, investor relations, government affairs and policy, and corporate communications. The allocation methods used to assign costs to Client Companies will be based on factors identified in Schedule 1 attached to the GSA.

Services and Service Level Arrangements (SLA)

Based on experience and discussions with the Client Companies, BSC has made available a list of service offerings that are defined in each SLA for the SLA period. Responsibilities of Client Companies for requesting services are defined in the SLAs. A listing of current SLAs can be found on the Exelon Intranet under Organizations – Business Services (under Popular Links).

Services provided will be reviewed on an as needed basis by BSC and Client Companies. SLAs will be prepared for on-going and for special services, which benefit one or more Client Companies. Examples of on-going services are payroll processing and IT desktop support. SLAs will be approved by the individual(s) authorized to represent BSC and each Client Company in accordance with Company Capital Approval Policies. In all cases, the authorized approvers representing BSC and the Client Company will be different individuals.

When a new service or project is identified, BSC Finance and BSC Accounting will determine whether a new SLA shall be used or whether the costs shall be captured in an existing SLA. One or more of the following criteria should be considered in determining the need for a new SLA:

1. No existing SLA uses the billing methodology that is needed for the new service project.

2. No existing SLA charges costs to the benefiting Client Company for the new service or project.

3. There is a specific regulatory requirement to allocate costs in a specific manner regardless of amount for the new project/service.

4. No existing SLA captures similar activity or services.

5. The total estimated annual cost of the new service or project is greater than $500,000.

SLA (Work Order) Monitoring and Control

BSC Finance and BSC Accounting are responsible for reviewing, monitoring and maintaining the SLA (Work Order) documentation. BSC Finance and BSC Accounting will also authorize new SLAs as necessary. A formal annual review will be required of all SLAs including a review by legal. As part of the annual review, inactive SLAs will be removed from the manual.

Allocation Factors Update and Revisions

Allocation factors will be based on cost drivers specifically applicable to the service provided. BSC Accounting will have the primary responsibility for ensuring that allocation factors are correct, accurate and current. BSC Finance and the Service Providers will assist in gathering required usage and other data to calculate the allocation factors.

BSC Accounting will be responsible for evaluating new allocation methodologies in coordination with the Legal Department. Adequate supporting documentation shall be obtained from all associate companies/business units for the raw data used in the allocation methodologies, and maintained in accordance with record retention requirements set forth in the Exelon record retention policy and schedule.

A list of current allocations will be filed annually with the FERC on FERC Form No. 60.

Time Reporting

All BSC employees, including executives, shall keep, within reasonable cost, time records supporting labor charged to separately identifiable goods and services performed for Client Companies. Time records are kept in a timekeeping management system or manually on time sheets.

Employees will record time weekly in a minimum of one-hour increments. Departments may elect to record employees' time in increments smaller than an hour to meet special needs.

The employee's immediate supervisor will review and approve time reports. The BSC Controller's organization will be the authorized delegate for the review of executive time records. Time records will be maintained in accordance with record retention requirements set forth in the Exelon record retention policy and schedule.

Billing and Review

BSC shall prepare a monthly invoice report detailing the services / products provided by Service Area for each Client Company. Payment shall be made by the Client Company by making remittance or by making (offsetting) accounting entries of the amount billed. Payment term (or appropriate offsetting accounting entries) is within thirty days of receipt.

Dispute Resolution Procedure

In the event there is a dispute between the Client Company and BSC regarding a billing methodology and/or amount, representatives of the Services and Client Companies will meet to discuss the issue. If a resolution cannot be reached among the Parties, the issue will be referred to each Party's executive management for final resolution.

Internal Audit Control

Internal Audit, under the direction of the General Auditor, will conduct periodic reviews of BSC's business processes and systems to ensure that the services provided are properly documented and charged to the Client Companies on an appropriate basis. Reviews shall be performed such that all major service areas are evaluated over time. Internal Audit will also conduct reviews of transactions and SLA charge methods to assess whether they comply with regulatory requirements. Internal Audit will also review the BSC allocations and corporate governance costs every two years.

Internal Audit maintains an independent role and has direct contact to Exelon's Audit Committee. Audit findings, recommendations and progress toward resolution of findings are reported to the Audit Committee and Senior Management as appropriate.

Budgeting

Budgeting for BSC will be a joint effort between it and other Client Companies. Renewal / revision of SLAs for the upcoming budget period will provide the basis for preparing budgets.

Evaluation

BSC will review its costs for competitiveness on a regular basis. Benchmarking and other measurement techniques will be used to the extent deemed appropriate by senior management. Additionally, BSC will also initiate a customer review process to gauge the value and quality of the services provided. Results will be shared with the Client Companies to allow them to evaluate cost effectiveness and assess alternate options.

EXHIBIT A

GENERAL SERVICES AGREEMENT

BETWEEN

EXELON BUSINESS SERVICES COMPANY

AND

EXELON CORPORATION; EXELON ENERGY DELIVERY COMPANY, LLC; COMMONWEALTH EDISON COMPANY; PECO ENERGY COMPANY; EXELON VENTURES COMPANY, LLC; EXELON GENERATION COMPANY, LLC; EXELON ENTERPRISES COMPANY, LLC; UNICOM INVESTMENT INC.; AND THE SUBSIDIARIES, AFFILIATES AND ASSOCIATES OF EACH LISTED ENTITY.

THIS AGREEMENT, made and entered into this 1st day of January, 2001, by and between the following Parties: EXELON BUSINESS SERVICES COMPANY ("Services Company"), EXELON CORPORATION; EXELON ENERGY DELIVERY COMPANY, LLC; COMMONWEALTH EDISON COMPANY; PECO ENERGY COMPANY; EXELON VENTURES COMPANY, LLC; EXELON GENERATION COMPANY, LLC; EXELON ENTERPRISES COMPANY, LLC; UNICOM INVESTMENT INC; AND THE SUBSIDIARIES, AFFILIATES AND ASSOCIATES OF EACH LISTED ENTITY (collectively, the "Client Companies");

WITNESSETH:

WHEREAS, Client Companies, including EXELON CORPORATION, which is registered under the terms of the Public Utility Holding Company Act of 1935 (the "Act") and its other subsidiaries, affiliates and associates desire to enter into this agreement providing for the performance by Services Company for the Client Companies of certain services as more particularly set forth herein;

WHEREAS, Services Company is organized, staffed and equipped and has filed with the Securities and Exchange Commission ("the SEC") to be a subsidiary service company under Section 13 of the Act to render to EXELON CORPORATION, and other subsidiaries, affiliates and associates of EXELON CORPORATION, certain services as herein provided; and

WHEREAS, to maximize efficiency, and to achieve merger related savings, the Client Companies desire to avail themselves of the advisory, professional, technical and other services of persons employed or to be retained by Services Company, and to compensate Services Company appropriately for such services;

NOW, THEREFORE, in consideration of these premises and of the mutual agreements set forth herein, the Parties agree as follows:

Section 1. Agreement to Provide Services

Services Company agrees to provide to Client Companies, upon the terms and conditions set forth herein, the services hereinafter referred to and described in Section 2, at such times, for such period and in such manner as Client Companies may from time to time request. Except with respect to "Corporate Governance Services" as defined in Section 7 hereof, the Services Company shall perform only those services as are requested by the Client Companies. Services Company will keep itself and its personnel available and competent to provide to Client Companies such services so long as it is authorized to do so by the appropriate federal and state regulatory agencies. In providing such services, Services Company may arrange, where it deems appropriate, for the services of such experts, consultants, advisers and other persons with necessary qualifications as are required for or pertinent to the provision of such services.

Section 2. Services to be Provided

The services expected to be provided by Services Company hereunder may, upon request by a Client Company, include the services as set out in Schedule 2, attached hereto and made a part hereof. In addition to those identified in Schedule 2, Services Company shall provide such additional general or special services, whether or not now contemplated, as Client Companies may request from time to time and Services Company determines it is able to provide.

Notwithstanding the foregoing paragraph, no change in the organization of the Services Company, the type and character of the companies to be serviced, the factors for allocating costs to associate companies, or in the broad general categories of services to be rendered subject to Section 13 of the Act, or any rule, regulation or order thereunder, shall be made unless and until the Services Company shall first have given the SEC written notice of the proposed change not less than 60 days prior to the proposed effectiveness of any such change. If, upon the receipt of any such notice, the SEC shall notify the Services Company within the 60-day period that a question exists as to whether the proposed change is consistent with the provisions of Section 13 of the Act, or of any rule, regulation or order thereunder, then the proposed change shall not become effective unless and until the Services Company shall have filed with the SEC an appropriate declaration regarding such proposed change and the SEC shall have permitted such declaration to become effective.

Section 3. Changes in Parties

New direct or indirect subsidiaries, affiliates and associates of EXELON CORPORATION, which may come into existence after the effective date of this Services Agreement, may become additional Client Companies of Services Company and subject to this General Services Agreement. In addition, entities which are, as of the effective date of this General Services Agreement, direct or indirect subsidiaries, affiliates and associates of EXELON CORPORATION, may thereafter leave the holding company system, in which case they will no longer be subject to this General Services Agreement. The parties hereto shall make such changes in the scope and character of the services to be provided and the method of assigning, distributing or allocating costs of such services as may become necessary to achieve a fair and equitable assignment, distribution, or allocation of Services Company costs among associate companies taking into account both the new subsidiaries and the subsidiaries which have left the holding company system, subject to the provisions of Section 2 above.

Section 4. Compensation of Services Company

As compensation for the services to be rendered hereunder, Client Companies listed in Attachment A hereto, as revised from time to time, shall pay to Services Company all costs which reasonably can be identified and related to particular services provided by Services Company for or on Client Company's behalf (except as may otherwise be permitted by the SEC). All other Client Companies and their affiliates and associates (see Attachment B) shall pay to Services Company charges for services that are to be no less than cost (except as may otherwise be permitted by the SEC), insofar as costs can reasonably be identified and related by Services Company to its performance of particular services for or on behalf of Client Company.

The services described herein or contemplated to be provided hereunder shall be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The factors for assigning or allocating Services Company costs to Client Company, as well as to other associate companies, are set forth in Schedules 1 and 2 attached hereto. Attachments A and B and Schedules 1 and 2 are each expressly incorporated herein and made a part hereof.

Any charges to the Client Companies on account of use of capital shall reflect a reasonable and efficient capital structure.

Section 5. Securities and Exchange Commission Rules

It is the intent of the Parties that the determination of the costs as used in this Agreement shall be consistent with, and in compliance with, the rules and regulations of the SEC, as they now exist or hereafter may be modified by the Commission.

Section 6. Service Review

The parties shall review each service covered by this Agreement on an as needed basis, to assess the quality of the service and to determine the continued need therefor, and shall, subject to the provisions of Section 2 above, amend the scope of services, delete services entirely from this Agreement, and/or decline services which are not "Corporate Governance Services," as defined in Section 7 hereof, as they determine to be necessary or desirable.

Section 7. Corporate Governance Services.

Whether or not requested by the Client Companies, the Services Company may provide to all Client Companies, and Client Companies shall pay Services Company for, “Corporate Governance Services.” Corporate governance consists of those activities and services reasonably determined to be necessary for the lawful and effective management of Exelon System businesses. Corporate Governance Services may be supplied from functions such as accounting, finance, executive, strategic planning, legal, human resources/benefits, audit, corporate communications and public affairs, environmental, health and safety, government affairs and policy, and investor relations. Corporate Governance Services may include, but are not limited to, the following: planning and project evaluation; finance and treasury; accounting and analysis; risk management; tax; shareholder and investor relations; merger and acquisition services; strategic planning; diversity; employee and labor relations; HR planning and development; compensation and benefits; legal services in the areas of securities, PUHCA, employment, regulatory, contract, litigation and intellectual property laws; legal and administrative support to the Board of Directors; environmental compliance activities; ethics and compliance programs; management services for compliance with Federal laws, regulations and other policy requirements, including relationship management with the U.S. Congress and Federal agencies; corporate communications; branding; corporate events; charitable support; community relations and communications to local organizations; and communications to employees.

Section 8. Payment

Payment shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of the companies involved. Invoices shall be prepared on a monthly basis for services provided hereunder.

Section 9. EXELON CORPORATION

Except as authorized by rule, regulation, or order of the SEC, nothing in this Agreement shall be read to permit EXELON CORPORATION, or any person employed by or acting for EXELON CORPORATION, to provide services for other Parties, or any companies associated with said Parties.

Section 10. Client Companies

Except as limited by law or order of the SEC, Client Companies, their subsidiaries, affiliates and associates may provide services described herein to other Client Companies, their subsidiaries, affiliates and associates on the same terms and conditions as set out for the Services Company.

Section 11. Effective Date and Termination

This Agreement is executed subject to the consent and approval of all applicable regulatory agencies, and if so approved in its entirety, shall be deemed effective from the date that the merger between PECO ENERGY COMPANY and UNICOM CORPORATION was consummated, and shall remain in effect from said date unless terminated by mutual agreement or by any Party giving at least 90 days' written notice to the other Parties prior to the beginning of any calendar year, each Party fully reserving the right to so terminate this Agreement.

This Agreement may also be terminated or modified to the extent that performance may conflict with any rule, regulation or order of the SEC adopted before or after the making of this Agreement. This Agreement shall be terminated with respect to any Client Company immediately upon such Client Company ceasing to be a member of the Exelon holding company system.

The Parties' obligations under this Agreement which by their nature are intended to continue beyond the termination or expiration of this Agreement shall survive such termination or expiration.

Section 12. Access to Records

Records will be maintained in accordance with 17 C.F.R. §257 and in any event no less than seven years following a transaction under this Agreement. The Client Company may request access to and inspect the accounts and records of the Services Company, provided that the scope of access and inspection is limited to accounts and records that are related to such transaction.

Section 13. Assignment

This Agreement and the rights hereunder may not be assigned without the mutual written consent of all Parties hereto.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and attested by their authorized officers as of the day and year first above written.

EXELON BUSINESS SERVICES COMPANY

By /s/ Ruth Ann M. Gillis
Ruth Ann M. Gillis
Title: President

EXELON CORPORATION,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES, AFFILIATES AND ASSOCIATES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Senior Vice President and Treasurer

EXELON ENERGY DELIVERY COMPANY, LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Vice President and Treasurer

COMMONWEALTH EDISON COMPANY,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Senior Vice President, Treasurer, and Chief Financial Officer

PECO ENERGY COMPANY,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Vice President, Treasurer, and Chief Financial Officer

EXELON VENTURES COMPANY LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Vice President, Treasurer, and Chief Financial Officer

EXELON GENERATION COMPANY, LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Vice President, Treasurer, and Chief Financial Officer

EXELON ENTERPRISES COMPANY, LLC,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Vice President and Treasurer

UNICOM INVESTMENT INC.,
ON BEHALF OF ITSELF AND ITS SUBSIDIARIES

By /s/ J. Barry Mitchell
J. Barry Mitchell
Title: Chairman, President and Chief Executive Officer,
Director, Vice President and Treasurer

Attachment A

Commonwealth Edison Company

Commonwealth Edison Of Indiana, Inc.

PECO Energy Company

Exelon Generation Company, LLC

Any subsidiary involved in directly providing goods, construction or services to the foregoing companies

Attachment B

All other Client Companies and their affiliates and associates not referred to in Attachment A.

Service Agreement Schedule 1

Allocation Ratios:

General:

Direct charges shall be made so far as costs can be identified and related to the particular transactions involved without excessive effort or expense. Other elements of cost, including taxes, interest, other overhead, and compensation for the use of capital procured by the issuance of capital stock, shall be fairly and equitably allocated using the ratios set forth below.

Revenue Related Ratios:

Revenues
Sales - Units sold and/or transported
Number of Customers

Expenditure Related Ratios:

Total Expenditures
Operations and Maintenance Expenditures
Capital Expenditures
Service Company Billings
Service Company SLA Billings (Non-governance)

Labor/Payroll Related Ratios:

Labor / Payroll
Number of Employees

Units Related Ratios:

Usage	(for example: CPU's, square feet , number of vendor invoice payments)
Consumption	(for example: tons of coal, gallons of oil, MMBTU's)
Capacity	(for example: nameplate generating capacity, peak load, gas throughput)
Other units related	

Assets Related Ratios:

Total Assets
Current Assets
Gross Plant

Composite Ratios:

Total Average Assets and 12 months ended Gross Payroll
Modified Massachusetts Formula

Other composite ratios

Service Agreement Schedule 2

<u>Services Including But Not Limited To:</u>

General:

Direct charges shall be made so far as costs can be identified and related to the particular transactions involved without excessive effort or expense. Other elements of cost, including taxes, interest, other overhead, and compensation for the use of capital procured by the issuance of capital stock, shall be fairly and equitably allocated using the ratios set forth in Schedule 1.

Administrative & management services including but not limited to:

- accounting
  - bookkeeping
  - billing
  - accounts receivable
  - accounts payable
  - financial reporting
- audit
- claims
- communications
- customer operations
- customer services
- executive
- finance
- insurance
- information systems services
- investment advisory services
- legal
- library
- record keeping
- secretarial & other general office support
- real estate management
- security holder services
- tax
- treasury
- other administration & management services

Expected allocation ratios: Revenue Related, Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Personnel services including but not limited to:

recruiting
training & evaluation services
payroll processing
employee benefits administration & processing
labor negotiations & management
other personnel services

Expected allocation ratios: Labor/Payroll Related, Units Related, Composite

Purchasing services including but not limited to:

preparation & analysis of product specifications
requests for proposals & similar solicitations
vendor & vendor-product evaluations
purchase order processing
receipt, handling, warehousing and disbursement of purchased items contract negotiation & administration
inventory management & disbursement
other purchasing services

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Facilities management services including but not limited to:

office space
warehouse & storage space
transportation facilities (including dock & port, rail sidings and truck facilities)
repair facilities
manufacturing & production facilities
fixtures, office furniture & equipment

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Composite

Computer services including but not limited to:

computer equipment & networks
peripheral devices
storage media
software

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Communications services including but not limited to:

communications equipment
audio & video equipment
radio equipment
telecommunications equipment & networks
transmission & switching capability

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Machinery management services including but not limited to:

equipment
tools
parts & supplies

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Composite

Vehicle management services including but not limited to:

automobiles
trucks
vans
trailers
railcars
marine vessels
aircraft
transport equipment
material handling equipment
construction equipment

Expected allocation ratios: Expenditure Related, Labor/Payroll Related, Units Related, Composite

Operational services including but not limited to:

drafting & technical specification, development & evaluation
consulting
engineering
environmental
safety
nuclear
construction

design
resource planning
economic & strategic analysis
research
testing
training
customer solicitation
support & other marketing related services
public & governmental relations
other operational services

Expected allocation ratios: Revenue Related, Expenditure Related, Labor/Payroll Related, Units Related, Assets Related, Composite

Exhibit B

Service Level Arrangement

Arrangement between _________________ Services Department and [Client Company]

Purpose

Governing Agreement

Term of Service

Scope of Services

Scope of Services

Service Responsibility Matrix

Services, Tasks		

Billing Approach

Pricing Table:

Service, Product # and Description	**Billing Approach, Basis, Service Owner**

Performance Metrics & Performance Reporting

Signatures	
Exelon Business Services Company, LLC _______________ _____ Signature Date	Name (Client) Title _______________ _____ Signature Date

S.F. Tierney Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants ________(G)

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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY
OF
SUSAN F. TIERNEY, Ph.D.
FORMAL CASE NO.____

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is Susan Fallows Tierney. I am employed at Analysis Group, Inc., 111 Huntington Avenue, 10^{th} Floor, Boston, Massachusetts, 02199.

2. Q. What is your position?

A. I am one of Analysis Group's Senior Advisors.

3. Q. What are your duties as a senior advisor at Analysis Group?

A. I am a lead consultant for many of our engagements with businesses, government agencies, non-governmental organizations, and other clients on matters relating to the electric and natural gas industries. For these projects, I supervise and work with teams of consultants with training in economics, business and finance, public policy and planning, math and computer science, and other fields.

4. Q. Please summarize your educational background and training.

A. I hold a Ph.D. in regional planning (1980) and a Masters in Regional Planning (1976), both from Cornell University. I was an assistant professor for

3.5 years at the University of California at Irvine, and have taught on a part-time basis at the Massachusetts Institute of Technology. I have lectured at numerous universities, including Harvard University, Yale University, MIT, New York University, Tufts University, the University of Pennsylvania, the University of Michigan, and others.

5. Q. Please describe your professional experience.

A. I have been involved in issues related to public utilities, ratemaking and regulation, and energy and environmental economics and policy for nearly 30 years. During this period, I have worked on electric and gas industry issues as a utility regulator and energy/environmental policy maker, educator, consultant, and expert witness. For more than 15 years, I have been a consultant and advisor on a variety of economic and policy issues in the energy sector. Prior to joining Analysis Group in July 2003, I was a consultant at Lexecon, Inc., and its predecessor, the Economics Resource Group, Inc.

Before that, I served in senior state and federal policy and regulatory positions for 13 years. I was the Assistant Secretary for Policy at the U.S. Department of Energy from 1993 through mid-1995. I held senior positions in the Massachusetts state government as Secretary of Environmental Affairs (1991-1993); Commissioner of the Department of Public Utilities (1988-1991); Executive Director of the Energy Facilities Siting Council (during the mid-1980s); and Senior Economist for the Executive Office of Energy Resources.

I currently sit on several non-profit boards and commissions, including serving as chair of the External Advisory Board of the National Renewable Energy Laboratory ("NREL"), chair of the Board of the ClimateWorks Foundation, and a director of World Resources Institute, the Alliance to Save Energy, and the Energy Foundation. I co-chair the NAESB Gas-Electric Harmonization Committee, am a member of the National Academy of Sciences panel on shale gas risk, and am co-lead author of the energy chapter of the National Climate Assessment. I am a member of the Bipartisan Policy Center's Energy Project, and the Environmental Advisory Council of the New York Independent System Operator. Previously, I served on the U.S. Secretary of Energy Advisory Board (and its Shale Gas Subcommittee), was a director of several companies (including EnerNOC, Inc.; Evergreen Solar; and Ze-gen, Inc), and served on the boards of several non-governmental organizations. On several occasions, I have served on technical review panels conducting peer reviews of DOE's national labs, including NREL's and the Energy Division of the Lawrence Berkeley National Laboratory ("LBNL"). I served as chair of the Policy Subgroup of the National Petroleum Council's study of the North American natural gas and oil resource base; chair of the Massachusetts Ocean Advisory Commission; co-chair of the National Commission on Energy Policy; a director of the Electric Power Research Institute; chair of the Electricity Innovation Institute's Board of Directors; a representative to committees of the North American Electric Reliability Council; a member of the National Academy of Sciences' Committee on Enhancing the Robustness and Resilience of Electrical Transmission and

Distribution in the United States to Terrorist Attack; and a member of the U.S. Secretary of Energy's Electric Reliability Task Force. My complete vita is attached as JOINT APPLICANTS (G)-1.

6. Q. Have you previously submitted testimony before state or federal bodies?

A. Yes. I have testified before utility regulatory agencies in many states, the Federal Energy Regulatory Commission, the U.S. Congress, several state legislatures, arbitration panels, and federal and state courts.

7. Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Exelon Corporation ("Exelon"), Pepco Holdings Inc. ("PHI"), and Potomac Electric Power Company ("Pepco") (together, the "Applicants") to provide testimony on the direct and indirect economic and policy benefits of their proposed merger (the "Merger"). At the request of the Applicants, I have reviewed the Application and have familiarized myself with the various commitments (the "Regulatory Commitments") the Applicants are making to the customers of Pepco and to the District of Columbia in support of the request for the District of Columbia Public Service Commission's ("Commission") approval of the proposed Merger. The Regulatory Commitments are enumerated in the Application. They are also described in more detail in the testimonies of the Applicants' witnesses.

8. Q. What are your overall conclusions about the economic benefits of the proposed Merger for Pepco customers and the economy of the District of Columbia?

A. As I describe in detail in my testimony below, the Merger offers many benefits to Pepco's District of Columbia customers and to the District of Columbia, itself, as a result of the Regulatory Commitments, which I summarize in Table SFT-1, below.

In terms of basic monetary commitments, Exelon pledges an amount of $100 million for the direct benefit of retail customers of all of the PHI companies, which is apportioned to the various companies based on the number of customers of each distribution company. In the District of Columbia, this Customer Investment Fund amounts to $14 million, or $52.95 per customer.

Additionally, Exelon has strengthened Pepco's commitments to reliability improvements for customers by pledging to be held financially accountable for the achievement of enhanced reliability performance goals ("Enhanced Reliability Commitments") by 2020.[1] Combined with reliability improvement projects already announced by PHI and underway (including the undergrounding project in Washington, D.C.), I calculate that the direct value to Pepco's retail customers of experiencing fewer and shorter service outages is $75.9 million.

[1] See the direct testimonies of Mr. Mark Alden ((Exelon's Vice President for Utilities Oversight) and Mr. Carim Khouzami (Exelon's Chief Integration Officer) for a description of Exelon's proposal to back-up its enhanced reliability commitments with a performance guaranty that will trigger a financial penalty if performance-improvement goals are not achieved.

Table SFT-1
Summary of Overall Benefits of the Proposed Merger

Benefits to:	Type of Benefits	Estimated Economic Benefits Associated with Merger's Regulatory Commitments to the District of Columbia:
Pepco customers	Tangible, quantifiable benefits	**Customer Investment Fund:** ▪ The Applicants will provide $14 million, which equates to $52.95 per distribution customer of Pepco. **Enhanced Reliability Commitments:** ▪ Pepco will continue implementation of its District of Columbia undergrounding project as currently planned and, moreover, to improve upon its reliability targets, with financial penalties in the event that Pepco does not achieve increased performance levels for system reliability. These benefits amount to $75.9 million in direct economic benefits to customers.

	Other unquantified benefits and commitments	**Rates and Costs:**
		▪ Pepco customers receive the benefit of synergy savings to Pepco in the future if/when rates are reset (assuming that such relies on a test year covering at least part of the first five years after the Merger is consummated).
		▪ Reliability and customer-service benefits from sharing best practices among the merged company's distribution companies.
		Regulatory Supervision and Governance:
		▪ Pepco and its parent submit to the jurisdiction of the Public Service Commission of the District of Columbia for all matters related to the Merger and the enforcement of these commitments, as well as to all matters relating to affiliate transactions among the various companies.
		▪ Customers of Pepco will be protected from business and financial risk exposures associated with its parent's unregulated operations and activities through appropriate ring-fencing provisions, which include a commitment to the following arrangements for at least 5 years following completion of the Merger:
		  ▪ Pepco will maintain its separate existence and its separate franchises and privileges, as well as maintaining separate books and records and will commit that all books and records pertaining to its regulated operations in the District of Columbia will be available for inspection and examination by the Commission.
		  ▪ Pepco will maintain separate debt so that it will not be responsible for the debts of affiliated companies and preferred stock, if any, and will maintain its own corporate and debt credit rating as well as ratings for long-term debt and preferred stock.
		  ▪ Pepco will maintain at least a common equity ratio consistent with the common equity ratios accepted in recent rate cases by the Commission for Pepco.
		Low Income Assistance:
		▪ Pepco commits to maintain and promote programs that provide assistance to low-income customers.
		Merger-Related Costs:
		▪ Pepco will not seek to recover any acquisition premium or transaction costs in rates, nor will it incur or assume any debt directly related to the Merger.

District of Columbia economy	Tangible, quantifiable benefits	**Direct, indirect and induced effects of the combined Customer Investment Fund and Enhanced Reliability Commitments on the economy of the District of Columbia:** ▪ 907 – 1,281 new jobs in the District of Columbia. ▪ Approximately $95.4 million – $133.6 million in overall economic value to the District of Columbia. ▪ Approximately $3.6 million – $5.5 million in incremental tax benefits to the District of Columbia.
	Other unquantified benefits and commitments	**Support for the District of Columbia's economic goals:** ▪ Continued local presence of a major corporation with strong community, economic and other goals: The Applicants will maintain the headquarters of Pepco's system, with appropriate levels of senior management, in the District of Columbia. The Exelon Board, Committee or Subsidiary Board meetings or Leadership meetings will be periodically held in the District of Columbia. ▪ Continued commitment to existing supplier diversity programs. **Support for community and charitable organizations in the District of Columbia**: ▪ Approximately $16 million over 10 years. In 2013, contributions amounted to about $1.6 million. **Employment benefits:** ▪ Commitment to honor all existing collective bargaining agreements. ▪ Commitment that, for at least 2 years following consummation of the Merger, there will not be a net reduction, due to involuntary attrition as a result of the Merger integration process, in the employment levels at Pepco and shall provide current and former employees at Pepco with compensation and benefits that are at least as favorable in the aggregate as the compensation and benefits provided to the employees immediately before the Merger Agreement.

Those two sets of tangible, quantifiable benefits to Pepco customers – the District-specific Customer Investment Fund and the Enhanced Reliability Commitments – provide not only direct and traceable financial benefits to Pepco's retail customers totaling $89.9 million in value, but also other, larger economic benefits to the District of Columbia's economy. Taking those two monetary commitments into account, I estimate conservatively that the Applicants' Regulatory Commitments introduce the following ranges of quantifiable economic benefits to the District of Columbia's economy (with the ranges based on different assumptions about how the Commission will decide to use the money in the Customer Investment Fund)[2]:

- 907 – 1,281 new jobs,
- $95.4 million – $133.6 million in overall economic value to the District of Columbia[3], and
- $3.6 million – $5.5 million in incremental tax revenues to the District of Columbia.

I say that those quantitative estimates of Merger benefits are conservative because they do not include several of the Applicants' other Regulatory Commitments that provide value to customers and the District of Columbia. For customers of Pepco, these other benefits (as shown on Table SFT-1) include[4]: the expectation that retail customers will receive the benefit of synergy savings at the next time that rates are reset (assuming that a test year is within the first five years after the Merger is consummated); the benefits associated with the Applicants'

[2] The estimates of economic impacts on the District reflect different scenarios and assumptions regarding potential uses of the Customer Investment Fund in the District of Columbia, including for (a) a one-time credit of $52.95 on each customer's electricity bill; (b) use of the funds for low-income customer bill assistance; and (c) energy efficiency programs. See further explanation in my testimony below.

[3] As described later in my testimony, overall economic value to the District is presented as economic "value added" in the macroeconomic model I use to calculate these benefits. This "value added" is separate from the direct value of the commitments that Pepco customers would receive.

[4] These other Merger commitments are described in detail in the testimony of Mr. Khouzami.

submitting to the jurisdiction of the Commission, their proposed "ring-fencing" provisions, the Applicants' commitment to retain low-income assistance programs, and the Applicants' commitment to not seek recovery of merger-related costs or any debt directly related to the Merger. For the District of Columbia, these other unquantified but nonetheless real benefits include Exelon's commitment to maintain Pepco's contributions to community and charitable organizations (which amounted to approximately $1.6 million in 2013); to maintain a "local presence" in the District of Columbia; to maintain existing supplier diversity programs; to honor all existing collective bargaining agreement and other labor-related actions during at least the first two years following consummation of the Merger. These various Regulatory Commitments provide real benefits to the communities in which Pepco conducts its utility service, but I have not quantified their monetary value here in my analysis.

9. Q. In reaching these conclusions and in your testimony more generally, did you focus on all aspects of the Merger?

A. No. I focused on the two elements of the package of Regulatory Commitments to the District of Columbia that the Applicants are making as part of their proposed Merger and that provide tangible, quantifiable benefits to Pepco customers. These Regulatory Commitments include those investments, expenditures, and other activities devoted to Pepco customers and the District of Columbia and pledged by Exelon and PHI as part of the Merger package. The Application provides substantial information on these commitments which has allowed me to provide quantitative estimates and qualitative assessments of the Merger's overall benefits in the District of Columbia.

10. Q. How is your testimony organized?

A. After this introductory section, I describe my analysis in Section II and provide a detailed discussion of my analytic framework, my analysis of benefits to Pepco customers, and my assessment of economic and policy benefits to the District of Columbia. In Section III, I briefly summarize my conclusions about the benefits to Pepco customers and to the District of Columbia.

11. Q. Before describing your analysis, please comment on whether there are aspects of the District of Columbia's electric reliability and economic-development policy goals that you found to be important as you reviewed the economic benefits of the proposed Merger.

A. I noted the attention of public officials and regulators on ensuring gradual improvement in Pepco's reliability performance for the benefit of customers. For example, I am aware that the Commission adopted new quality of service standards in 2011.[5] Also, I understand that after the 2012 Derecho and other extreme weather events, the Commission reviewed Pepco's planning and preparation prior to the storms,[6] and that the Power Line Undergrounding Task

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5 "District Regulators Tighten Reliability Standards for Pepco," Public Service Commission of the District of Columbia, Press Release, July 8, 2011, available at: http://205.177.170.130/pdf_files/pressreleases/DRTRS_for_Pepco.pdf.

6 "District Regulators Require Answers about Pepco's Performance," Public Service Commission of the District of Columbia, Press Release, July 5, 2012, available at: http://205.177.170.130/pdf_files/pressreleases/PR_PSC_Pepco_Performance.pdf.

Force further investigated reliability issues in the District of Columbia.[7] Additionally, I am aware of the 2014 legislation authorizing revenue bonds to help support undergrounding of parts of the Pepco distribution system. [8]

I note further that Pepco has already made significant progress to accomplish reliability improvements, as reflected in its recent reliability metrics.[9] I also recognized that the Commission has sought to balance the level and speed of reliability improvements with customer rate impacts. I conducted my assessment of the Merger with these electric-reliability and ratemaking goals in mind, and noted that the Merger builds upon the sound policy guidance expressed by the Commission while strengthening the Company's ability to reach the targeted improvements through the institutional and financial commitments accompanying the Merger.

[7] "This summer's [2012] severe weather events resulted in multi-day power outages. Mayor Gray has voiced his strong concern about the repeated outages and said the District needed a 'game changer' to prevent the hardship caused by such power failures in the future. To that end, he has appointed top administrators, financial officials, utility industry leaders and residents of heavily impacted areas to study the feasibility of burying power lines underground, potential associated costs, and other alternatives for short-term solutions." Source: "Mayor Vincent C. Gray to Hold First Meeting of the Power Line Undergrounding Task Force," Executive Office of the Mayor, Press Release, August 22, 2012, available at: http://205.177.170.130/pdf_files/pressreleases/Undergrounding_Task_Force_Meeting_Advisory.pdf.

[8] Please note that one of the commitments in the preliminary Merger Agreements was that Pepco would continue to implement the undergrounding project as planned.

[9] I have reviewed the testimony of Mr. Alden and Mr. William Gausman (PHI's Senior Vice President for Strategic Initiatives).

II. ANALYSIS OF THE ECONOMIC BENEFITS OF THE PROPOSED MERGER'S REGULATORY COMMITMENTS

A. Overview

12. Q. Please provide an overview of your analysis of the benefits of the proposed Merger.

A. As stated previously, I focused my review and assessment on the Applicants' Regulatory Commitments in the District of Columbia. I performed two types of quantitative analyses: one focused specifically on the measurable and direct benefits that will flow to the District of Columbia *customers* of Pepco as a result of two elements of the Regulatory Commitments (i.e., the Customer Investment Fund and the Enhanced Reliability Commitments); in the other, I calculated economic impacts of these two regulatory commitments on the *overall economy of the District of Columbia* in which Pepco provides utility service. As part of the latter analysis, I utilized IMPLAN, a commonly used proprietary modeling tool, to quantify these effects.[10] Specifically, I estimated the direct, indirect and induced impacts of the relevant Regulatory Commitments on employment, income, and the creation of net economic value ("value added") in the District of Columbia.

In addition, I have noted other elements of the Regulatory Commitments that provide intangible but still important benefits to the customers of Pepco and to the District of Columbia as a result of an approved Merger.

13. Q. Please describe IMPLAN in general terms.

[10] IMPLAN (the "IMpact analysis for PLANning") model, available at http://implan.com.

A. The IMPLAN model is a social accounting/input-output model that attempts to replicate the structure and functioning of a specific economy. The model allows one to investigate various interactions in a defined economy (in this case, the District of Columbia) and to calculate various economic impacts in that economy when a new activity introduces a change in the conditions in the economy. A typical change could be an investment in a new facility being built in the District, or a new government program to support an economic development strategy. IMPLAN is widely used by government agencies, companies, academics, and others to evaluate the economic impacts of such different activities. JOINT APPLICANTS (G)-2 provides a sampling of applications of IMPLAN in analyses conducted for agencies of the District of Columbia.

In this particular instance, the changes in economic activity that are occurring as part of the Applicants' Regulatory Commitments are: (a) the monetary payment associated with the new "Customer Investment Fund," supplied by shareholders of one utility (e.g., Exelon) as part of its acquisition of another utility (e.g., PHI) and to be used for the benefit of customers of the acquired utility; and (b) the economic value that customers will experience associated with their being exposed to fewer and shorter electric service outages (i.e., the Enhanced Reliability Commitments).

IMPLAN relies on a detailed system of accounting for relationships among different parts of an economy, and employs state-specific national economic data for the relevant region. The model provides estimates of impacts such as new income and employment, "value added" effects (the net economic value to the economy after taking into account the input costs), and the impacts on state and local taxes.

While the model is focused on economic activity inside an economy, the model tracks the movement of money and people into and out of that economy. For example, IMPLAN tracks the effects of money injected into an economy (e.g., the provision of funding for the new Customer Investment Fund in the District of Columbia) from an outside source, with various economic interactions and dollars flowing from that new activity. At the same time, activities that occur outside of the economy (such as the local utility's purchases of new electric distribution equipment or very-efficient lighting devices manufactured or produced outside of the District of Columbia) show up in the model's accounts in the form of money or people exiting the economy. The model thus examines inflows, outflows, and interactions within the economy under study.

In JOINT APPLICANTS (G)-3, I have provided more information on the IMPLAN model and certain definitions of terms it uses.

14. Q. What are the key concepts and IMPLAN terms that you use in your analysis?

A. As described in more technical terms in JOINT APPLICANTS (G)-3, I track several core impacts of new economic activity associated with the two elements of the Regulatory Commitments that I have quantified (the Customer Investment Fund and the value of Enhanced Reliability Commitments to customers):

- *Employment effects* (the total number of jobs created); and
- *"Value-added" effects* (the total economic value added to the economy, which reflects the gross economic output of the area less the cost of the inputs).

There are various ways in which the new activity creates impacts, each of which is separately tracked by the model:

- *Direct effects* (the initial set of inputs that are being introduced into the economy, such as dollars associated with the Customer Investment Fund, or the value (or avoided costs) to customers of experiencing shorter and/or fewer electric outages as a result of Enhanced Reliability Commitments to improve electric distribution system reliability);
- *Indirect effects* (the new demand for local goods, services and jobs as a result of the new activity, such as use of the Customer Investment Fund to purchase goods and services related to energy efficiency, or the indirect effects of having shorter/fewer outages); and
- *Induced effects* (the increased spending of workers resulting from income earned from direct and indirect economic activity, or customers' purchases as a result of having received a credit on their utility bill).

Finally, I also track the District of Columbia taxes that flow from these direct, indirect and induced effects.

15. Q. When you used IMPLAN to model the economic impacts of the Applicants' Regulatory Commitments in the District of Columbia, how did you frame your analysis?

A. I made appropriately different assumptions for modeling the economic impacts of the two types of Regulatory Commitments I analyzed quantitatively.

16. Q. Please explain your core assumptions about modeling the economic impacts of the Customer Investment Fund.

A. I assumed that the Customer Investment Fund would operate as a one-time infusion of dollars in 2015 leading to some potential economic activity as directed by the Commission. The direct infusion of money flowing into the District of Columbia's economy amounts to $14 million, provided by Exelon for the benefit of Pepco customers through the Customer Investment Fund. Depending upon the Commission's decisions about how to use that fund, the combined direct, indirect and induced impacts of that initial investment amount could vary, and my analysis (described further below) provides illustrations of the types of macroeconomic effects that could occur through different uses of the fund.

17. Q. Regarding the economic impacts of the Enhanced Reliability Commitments, how did you frame your analysis through IMPLAN?

A. Based on the expectation that the Enhanced Reliability Commitments will cause customers to experience fewer outages and service disruptions of shorter length, and that the fact that the Enhanced Reliability Commitments will enable avoidance of cost impacts (i.e., out-of-pocket costs and/or lost opportunity costs) or other damages associated with outages, I then used estimates of those avoided costs as inputs to IMPLAN in order to calculate the economic value to the economy of the District of Columbia that will result from shorter/less-frequent electric distribution-system outages.

I made a number of assumptions about the ways in which the Regulatory Commitments would show up in economic activity in the District of Columbia's economy; I list these core assumptions in JOINT APPLICANTS (G)-4. I provide the results of the basic analyses in the description of my assessment, below.

18. Q. Does IMPLAN provide an estimate of the impacts of the Regulatory Commitments on Pepco customers *per se*?

A. No. The IMPLAN analysis focuses on the effects on the District of Columbia economy at large, and does not track how those would specifically affect the customers of Pepco. That is why I chose to specifically discuss those singular impacts on Pepco customers as a separate piece of analysis and in a separate portion of my testimony, below.

B. Assessment of the Tangible and Intangible Impacts of the Regulatory Commitments on Pepco Customers

19. Q. Please describe the ways that the customers of Pepco will be directly affected by the proposed Merger.

A. Several aspects of the proposed Merger will result in direct, tangible, and measurable benefits to Pepco customers. Together, these amount to approximately $89.9 million in direct benefits that will flow to Pepco customers if the Merger is approved and consummated. This estimate is based on the combined monetary benefits to customers from the Customer Investment Fund and the Enhanced Reliability Benefits.

20. Q. Which Regulatory Commitment provides the highest monetary value to Pepco customers?

A. Although the Applicants' upfront cash contribution to the Customer Investment Fund is a highly concrete and visible commitment being offered for the benefit of Pepco's customers, the Enhanced Reliability Commitments ends up providing more value to customers than the Customer Investment Fund. The value associated with these two types of commitments may affect how the Commission weighs options for use of the money in the Customer Investment Fund. Although the decision as to how to direct the Customer Investment Fund will be up to the Commission, my analysis could provide some early insights into the trade-offs of how to spend the money to allow different customer segments to share in the value of the Merger benefits. My discussion below highlights some of the relevant issues.

21. Q. Please describe the value of the Customer Investment Fund to Pepco customers.

A. The Regulatory Commitment with the most direct benefit and obvious monetary value to Pepco customers is the one-time contribution by Exelon of $14 million to the Customer Investment Fund, which equates to $52.95 for every customer buying utility service from Pepco.

For context, this particular Regulatory Commitment equates to roughly 2.7 weeks of "free" bundled electricity service (or 1.7 months of free electric delivery service) for a typical residential electric customer.[11] Alternatively, it reflects approximately 102 percent of the District of Columbia Sustainable Energy Utility's spending on customer-funded energy efficiency programs in 2013.[12]

22. Q. How does the size of this customer contribution compare to other recent mergers?

A. Based on my review of other recent utility mergers and acquisitions, the $52.95/customer contribution is larger than in most other corporate consolidations approved by utility regulators. Among all mergers or acquisitions of investor-owned electric and electric/gas utilities since 2010, the per-customer amounts range from $11/customer to $100/customer, with all but one falling below $30/customer, as summarized in Table SFT-2, below.

[11] This assumes that average bills for a residential Pepco electric customer are as follows: delivery service at $374 per year, or $31 per month; and bundled electric service at $1,022 per year, or $85 per month. These estimated rates are based on 2012 data, and assume no change in base rates (for distribution charges) and known supply rates for standard offer service customers. Source: the Applicants and Energy Information Administration ("EIA") Form-861 2012 data. The $52.95 on-bill credit to each residential customer could also be seen as approximately 14 percent of the typical residential electric customer's annual delivery charges, or five percent of his/her typical total annual electric bill.

[12] 2013 energy efficiency totals come from the District of Columbia Sustainable Energy Utility's 2013 Annual Report.

TABLE SFT-2
Monetary Commitments of the Acquiring Utility to the Direct Benefit of Customers of the Acquired Utility: Recent Mergers/Acquisitions of Investor-Owned Electric and Electric/Gas Utilities Since 2011

Acquirer	Target Acquisition	State	Year	Pledge	Total Amount (million $)	# of Customers Receiving Credit	Average Amount per Customer	Sources
FirstEnergy	Allegheny (Potomac Edison)	MD	2011	$/Customer and Total $	$6.5 million	~224,138 (residential)	$29.00	[1], [2]
	Allegheny (Potomac Edison, Monongahela Power Co.)	WV	2011	Total $	$7.5 million (over 2 years)	522,864 (all classes)	$14.34	[3], [4]
	Allegheny (West Penn Power Co.)	PA	2011	Total $	$10.8 million (over 3 years)	620,151 (residential)	$17.42	[4], [5]
Northeast Utilities (NU, Western Massachusetts Electric Co, Connecticut Light & Power)	NSTAR	CT	2012	Total $	$25 million	1,215,257 (all classes)	$20.57	[6], [7]
	NSTAR (NSTAR Electric)	MA	2012	Total $	$15 million	1,172,997 (all classes)	$12.79	[6], [8], [9]
	NSTAR (NSTAR Gas)	MA	2012	Total $	$3 million	~272,000 (all classes)	$11.03	[7], [8], [9], [10]
	NSTAR (Western Massachusetts Electric Co.)	MA	2012	Total $	$3 million	211,185 (all classes)	$14.21	[6], [8], [9]
MidAmerican	NV Energy (Nevada Power Company; Sierra Pacific Power Company)	NV	2013	Total $	$20 million	1,300,000 (all classes)	$15.38	[6], [11], [12]
Exelon	Constellation (BGE)	MD	2012	$/Customer and Total $	$112 million	~1,120,000 (residential)	$100.00	[13], [14]

Notes:

[1] Unless otherwise specified, rate credits are assumed to be spread across all rate classes.

Sources

[1] Maryland Public Service Commission, Order No. 83788, January 18, 2011.

[2] "MD PSC approves Allegheny Energy Merger with FirstEnergy," The Daily Record, January 19, 2011.

[3] "West Virginia PSC approves Allegheny Energy/First Energy merger proposal," SNL Financial, December 16, 2010.

[4] EIA 861 file-2, 2011.

[5] "Allegheny Energy, FirstEnergy tout merger benefits," Herald-mail, January 22, 2011.

[6] EIA 861 file-2, 2012.

[7] "NU and NSTAR Reach Comprehensive Merger-Related Agreement with Connecticut AG and OCC," Company Release, March 13, 2012.

[8] "Massachusetts Department of Public Utilities Announces Approval of NSTAR - NU Merger," MA Executive Office of Energy and Environmental Affairs, Press Release, April 5, 2012.

[9] "UPDATE: NSTAR, NU agree to more renewables, rate freeze in Mass. merger deal," SNL Financial, February 15, 2012.

[10] Northeast Utilities 2012 Annual Report

[11] "MidAmerican Energy holdings Company and NV Energy, Inc. Merger Complete," MidAmerican Press Release, December 19, 2013.

[12] "Nev. Regulators OK with MidAmerican's Acquisition of NV Energy, with stipulations," SNL Financial, December 16, 2013.

[13] "Exelon's proposed acquisition of Pepco Holdings," SNL Financial, RRA Special Report, May 7, 2014.

[14] "In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc., - Supplemental Testimony of Susan F. Tierney, Ph.D. In Support of the Joint Petition for Approval of Settlement," Before the PSC of Maryland, Case No. 9271, December 15, 2011.

All mergers and acquisitions are different and provide different opportunities for contributing value to customers at the outset of the transaction versus over time (as synergy opportunities end up affecting the utility's cost of service and customer rates). Exelon's proposed contribution to a Customer Investment Fund based on $52.95/customer represents an amount above the range of all but one recent merger and acquisition approved by state regulators (i.e., the Exelon/Constellation Merger).

23. Q. Do you know whether each customer will actually receive exactly $52.95 as contributed by the Applicants?

A. No. The Applicants have offered this Regulatory Commitment in a form that anticipates the Commission determining the appropriate use of the Customer Investment Fund. The Commission might choose to disburse the Customer Investment Fund to customers in the form of a one-time customer credit on each customer's electric bill. Or, the Commission might decide to use the funds to support incremental energy efficiency investments, which might not only fund efficiency measures on customer premises but also lead, over time, to lower demand in the relevant wholesale markets with resulting effects on lowering energy prices paid by customers over many years. Or, the Commission might allocate some portion to low-income customer assistance, or to targeted reliability improvements, and/or any other public-interest benefit deemed to be valuable to customers of Pepco. These diverse examples underscore that different uses of the funds will likely lead to different types of impacts for different types of customers.

As I explain further below, the Commission might decide to distribute this benefit on an equal basis to all customers (e.g., through a $52.95/customer credit on each customer's bill), or disproportionally in favor of those customers who receive fewer of the other types of benefits likely to flow from the Merger (e.g., to residential customers and/or low-income residential customers, for whom the economic value of other Regulatory Commitments, such as the Enhanced Reliability Commitments, may be lower than it is to commercial and industrial customers), or exclusively through investments that will lead to longer-term additional benefits over time (e.g., through use of the money for energy efficiency programs that end up lowering costs to all customers over time). But from a system-wide point of view, the $52.95/customer contribution to the Customer Investment Fund is a direct and traceable financial benefit of the proposed Merger for District of Columbia customers, totaling $14 million.

24. Q. Have you quantified any other Regulatory Commitment in terms of benefits provided to customers of Pepco in the District of Columbia?

A. Yes. I have quantified the value to customers associated with the Applicants' strengthened commitments to achieve improvements in the local distribution-system reliability that accrue to the benefit of customers (i.e., the Enhanced Reliability Commitments).

25. Q. Please describe the Enhanced Reliability Commitments and how you have estimated the economic value of this benefit to customers.

A. Based on the direct testimonies of Mr. Mark Alden (Exelon's Vice President for Utilities Oversight) and Mr. William Gausman (PHI's Senior Vice President for Strategic Initiatives), I understand that Exelon has committed to further strengthening Pepco's recently demonstrated progress to improving reliability in two ways: first, by committing to performance outcomes by 2020 that will result in less frequent outages of utility service to customers; and second, by committing to putting shareholders' money on the line (i.e., in the form of financial penalties) in the event that the utility does not meet those guaranteed performance outcomes by 2020, as measured by a set of quantifiable metrics reflecting actual performance in a three-year period (2018-2020).

26. Q. Please define the foregoing reliability metrics.

A. There are several metrics that are commonly used in the electric industry to measure how often and how long customers undergo outages of electricity service. The more common metrics are "SAIFI," "SAIDI," and "CAIDI". "SAIFI" stands for "system average interruption frequency index," and reflects the average number of sustained service interruptions per customer during a time period. "SAIDI" stands for "system average interruption duration index," and reflects the length of time that customers are without service. "CAIDI" stands for the "customer average interruption duration index," and reflects the average duration of interruptions experienced by a customer during a time period.

SAIFI is typically calculated through the following formula:

SAIFI = total number of customer interruptions divided by the total number of customers served.

SAIDI, in turn, is typically calculated according to the following formula:

SAIDI = sum of all customer interruption durations divided by the total number of customers served.

CAIDI is typically calculated according to the following formula:

CAIDI = the sum of the duration of all customer interruptions divided by the total number of customer interruptions (or, SAIDI divided by SAIFI).

Thus, SAIFI indicates how often a customer has a service interruption, SAIDI expresses how long all customers go without power (i.e., the average length of service disruptions faced by customers), and CAIDI represents how long each customer experiences an outage on average.

Utilities commonly use these indices to benchmark reliability, because they provide a reference point for characterizing the frequency and duration of interruptions for a particular company during a reporting period, how that utility compares to other utilities' service, and how a utility's performance changes over time.

27. Q. Are there factors that affect a company's performance with regard to service frequency and service duration outages?

A. Yes. There are many factors that can affect a company's performance on these metrics. For example, the extent to which a system's distribution and transmission system is located underground may affect outages (both their frequency and the length of time to repair equipment in the event of damage). Similarly, the amount of tree coverage and the tree-trimming practices of the utility could affect performance. Other factors can include weather events, age of facilities, utility metering and data-management systems used to collect information on and address outage conditions, and utility practices for system restoration. In recent years, for example, extreme weather events have wreaked havoc on energy and other critical infrastructure in the District of Columbia, and have disrupted electric service to homes, businesses and other critical systems.

28. Q. Are you aware of any studies that estimate the economic costs of unreliable electric service to customers?

A. Yes. One early study (2004) conducted by the LBNL estimated the national cost of power interruptions at $80 billion annually, with a likely range of $30 billion to $130 billion after a sensitivity analysis.[13] More recently, a 2013 study issued by the Executive Office of the President estimated the average cost to the U.S. economy of power outages caused only by severe weather at between $18 billion to $33 billion annually for the years 2003 to 2012.[14] The report notes that annual costs can fluctuate significantly and are greatest in the years of major

[13] Kristina LaCommare and Joseph Eto, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers," Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-55718, September 2004.

[14] "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," Executive Office of the President, August 2013, available at http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf.

storms such as Hurricane Ike in 2008, a year in which cost estimates range from $40 billion to $75 billion, and Superstorm Sandy in 2012, a year in which cost estimates range from $27 billion to $52 billion. A 2012 Congressional Research Service study estimates the inflation-adjusted cost of weather-related outages at $20 to $55 billion annually.[15] Additionally, as co-lead convening author of the recent National Climate Assessment's chapter on "Energy Supply and Use," I am aware of the literature on the impacts of extreme weather events and other climate-related conditions and trends on energy infrastructure (such as electric transmission and distribution systems) and of related impacts on customers of critical services (like electricity) that depend upon that infrastructure.[16]

29. Q. What is your understanding of Exelon's commitments to improving service-quality performance of Pepco?

A. I understand that Exelon proposes to use the following metrics to enable the Commission to measure Pepco's reliability outcomes by 2020, as summarized in Table SFT-3:

[15] Richard J. Campbell, "Weather-Related Power Outages and Electric System Resiliency," Congressional Research Service, August 28, 2012. http://www.fas.org/sgp/crs/misc/R42696.pdf.

[16] See J. Dell, S. Tierney, G. Franco, R. G. Newell, R. Richels, J. Weyant, and T. J. Wilbanks, 2014: Ch. 4: Energy Supply and Use. *Climate Change Impacts in the United States: The Third National Climate Assessment*, J. M. Melillo, Terese (T.C.) Richmond, and G. W. Yohe, Eds., U.S. Global Change Research Program, 113-129. doi:10.7930/J0BG2KWD. http://nca2014.globalchange.gov/report/sectors/energy . See additionally, T. Wilbanks, S. Fernandez, G. Backus, P. Garcia, K. Jonietz, P. Kirshen, M. Savonis, B. Solecki, and L. Toole, 2012: Climate Change and Infrastructure, Urban Systems, and Vulnerabilities. Technical Report to the U.S. Department of Energy in Support of the National Climate Assessment, Oak Ridge National Laboratory. U.S. Department of Energy, Office of Science, Oak Ridge, TN. http://www.esd.ornl.gov/eess/Infrastructure.pdf.

Table SFT-3
Applicants' Enhanced Reliability Commitments for Pepco

	Historical Performance (3-Year Average: 2011-2013)	Average Performance Commitment from the Merger by 2020 (Based on 3-Year Average: 2018-2020)	Change in Performance
SAIFI	1.03	0.54	48%
SAIDI	149	107	28%
Source: Testimony of Mr. Mark Alden.			

I understand that these Enhanced Reliability Commitments result in part from the Applicants' plan to share best practices across all of the distribution utilities that will be part of the merged entity's holding company, with opportunities for improvements for Pepco operations and for customer service.[17]

30. Q. In light of Pepco's expected requirements, why do you think that the Merger will provide benefits to customers in terms of reliability of service?

A. This Merger commitment will provide value to customers by avoiding outages of electricity service which otherwise have well-known and adverse impacts on customers' household activities, their business operations, and other aspects of their day-to-day lives. The value to customers of shorter and fewer outages is that they will experience lower economic and other negative impacts from outages.

31. Q. How have you translated this Enhanced Reliability Commitments into a specific benefit to customers?

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[17] For example, in his testimony, Mr. Alden describes Exelon's Management Model (a management system designed to identify and generate best practices for operational excellence at each of its utilities and to share and implement those practices system-wide), including such things as standardized "Lock Out" and "Tag Out" ("LOTO") practices to restore service during emergency response events.

A. I have interpreted Exelon's new Regulatory Commitment to absorb a financial penalty for non-performance on guaranteed reliability metrics as a strengthening of Pepco's prior commitment to improve electric system reliability for customers. In addition, Exelon has committed to reliability improvements by the end of 2020 that go beyond those commitments now in place for Pepco. My understanding is based substantially on other witnesses testifying on behalf of the Applicants, including Mr. Alden and Mr. Gausman.

32. Q. What is the basis for your view that such reliability improvements will provide economic benefits to Pepco's customers?

Much has been written about the value of reliability to customers in recent years.[18] Studies have examined the types of costs incurred by electricity customers during outages, which include out-of-pocket costs associated with business disruptions (e.g., damage to equipment), opportunity costs resulting from inability to access electric service (e.g., inability to provide restaurant services that cannot be made up when electricity service is resumed on another day), lost perishables (e.g., food lost due to loss of refrigeration), diminished capability to provide critical services (e.g., street lighting, telecommunications, pumping of gasoline), public health impacts (e.g., due to loss of heating or cooling during extreme weather periods), adverse impacts on quality of life (e.g., due to loss of

[18] Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A Freeman, Sullivan & Co, "Estimated Value of Service Reliability for Electric Utility Customers in the United States," Prepared for Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, by the Energy Analysis Department (Environmental Energy Technologies Division), Ernest Orlando Lawrence Berkeley National Laboratory, June 2009, http://certs.lbl.gov/pdf/lbnl-2132e.pdf; Michael J. Sullivan, Matthew G. Mercurio, Josh A. Schellenberg, and Joseph H. Eto, LBNL, "How to Estimate the Value of Service Reliability Improvements," 2010, http://certs.lbl.gov/pdf/lbnl-3529e.pdf.

electricity for cooking, lighting, electronic equipment at homes), and many other impacts. These impacts vary by type of customer; time of day, day of the week, and season of the year during which an outage occurs; length and frequency of outages; extent to which there are substitutes for electricity service; the extent to which an economy depends upon electricity (i.e., its electricity intensity); and other factors. Economic studies have examined these various impacts and quantified the cost of outages and the related value of reliable service. These studies consistently indicate that the value that customers place on reliable electricity service exceeds the cost of paying for electricity service.

33. Q. How have you quantified the value to customers of such reliability improvements?

A. I have based my assessment on an economic analysis of the 'value of reliability.' which is customers' avoided economic loss(es) associated with outages. The value of reliability shows up in customers experiencing lower costs and other lower adverse impacts as a result of having fewer and shorter interruptions of electricity service.

More specifically, I have quantified the value to customers as a whole by using a publicly available, on-line calculator (the "Interruption Cost Estimator" ("ICE Calculator")[19]) provided by the U.S. Department of Energy ("DOE") and based on research and analysis from the DOE's national laboratory, LBNL.[20]

[19] "The Interruption Cost Estimate (ICE) Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and LBNL. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the

Using information about the value of reliability and the costs of outages to customers, I proceeded as follows to estimate the value of Enhanced Reliability Commitments (and associated reliability improvements) to customers. First, I entered the three-year average historical values (2011-2013) from Table SFT-3 into the ICE Calculator to populate the "without reliability improvements" scenario in the model.[21] Second, to determine the inputs for the "with reliability improvements" scenario, I entered an annual value for each year between 2015 and 2020 by calculating a linear trend between the historical values and the 2018-2020 average commitment values from Table SFT-3. I also entered the number of residential and non-residential customers, and otherwise accepted the District-specific default values that the ICE Calculator contains.

The resulting output from the ICE Calculator provides two important results that I used in my quantification of benefits: the annual benefits resulting from the reliability improvements for each year between 2015 and 2020, and the portion of benefits attributable to residential versus non-residential (i.e., commercial and industrial) customers. I then calculated the net present value of

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benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy." http://www.icecalculator.com/ice/

[20] As indicated in a prior footnote, LBNL has conducted much of the research to compile information about value of reliability service to retail electricity customers.

[21] The ICE Calculator includes three settings: 1) calculating the cost of an interruption event, 2) estimating the value of a reliability improvement in a static setting (where reliability does not improve over time), and 3) estimating the value of a reliability improvement in a dynamic setting based on forecasts of SAIDI, SAIFI, and CAIDI. I used the setting that allows for calculating benefits in a dynamic environment.

these reliability benefits over the period from 2015 through 2020 using a social discount rate.[22]

34. Q. What are the results of your assessment of the direct value of the Enhanced Reliability Commitments to Pepco's customers?

A. The results, shown in Table SFT-4, reflect the different economic impacts on residential customers as well as commercial and industrial customers, who often experience direct business losses and opportunity costs in addition to the inconvenience of service disruptions. As indicated, these customer benefits are substantial.

Table SFT-4
Total Dollar Benefit:
Pepco Customers (DC)

	All Company Customers	Average Benefit per Customer
Residential	$2,276,047	$9.56
Commercial and Industrial	$73,592,171	$2,786

Note: Amounts are shown as Net Present Value ("NPV") of Benefits (2014$), 2015-2020.

35. Q. What is your estimate of the total value to customers of the Applicants' two Regulatory Commitments (i.e., the Customer Investment Fund and the Enhanced Reliability Commitments)?

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22 The discount rate is the tool that accounts for the time value of money – the concept that a dollar today is typically worth more than the same amount of money in the future because of the opportunity cost of money to various private and public entities in society. I used a social discount rate (i.e., 3 percent) in my analysis because it reflects dollars in the hands of producers, who are largely private enterprises, and consumers, made up of households, businesses, government energy users, and others. See, e.g., U.S. Environmental Protection Agency (National Center for Environmental Economics, Office of Policy), "Guidelines for Preparing Economic Analyses," EPA 240-R-10-001, December 2010, pages 6-7 to 6-8 ("As of the date of this publication, current estimates of the consumption rate of interest, based on recent returns to Government-backed securities, are close to 3%.").

A. Based on $14 million in the Applicants' payments to the Customer Investment Fund and the $75.9 million in value associated with the Enhanced Reliability Commitments, I conservatively calculate that the Merger will provide $89.9 million in direct and traceable financial benefits to customers. These benefits are summarized in Table SFT-1.

36. Q. Are there other benefits that Pepco customers will receive, on top of the $89.9 million you describe above?

A. Yes. There are other, less-easily-measurable but still-important benefits that will flow to Pepco's customers if the Merger is consummated.

First, Pepco's customers will receive the benefit of the Merger's synergy savings to Pepco.[23] In future rate cases based on test years after the Merger is consummated, Pepco's cost of service will be lower than it would otherwise have been in the absence of the Merger. This is the effect of the incremental synergy savings from the Merger (net of costs to achieve those savings) that arise over time. In fact, the company's customers will receive the benefits of synergy savings twice: once in the form of the immediate share of the Customer Investment Fund (equivalent to approximately $52.95 per-distribution-customer credit in 2015); and then again when rates are reset in the future (assuming that such relies on a test year covering at least part of the first five years after the Merger is consummated).

[23] Mr. Khouzami describes such merger synergies in his direct testimony.

Second, the Applicants have committed to retain and promote current assistance provided to low-income customers.

Third, the Applicants have made commitments to the District of Columbia with respect to regulatory supervision and corporate governance, all of which will provide protections to customers of Pepco. As described by Mr. Khouzami, these protections include not only the commitment to submit to the jurisdiction of the Commission on matters related to the Merger and the enforcement of commitments and on matters related to affiliate transactions, but also the commitment to 'ring-fence' the distribution company Pepco to separate it from the business and financial risks associated with the Applicants' unregulated business activities. These latter commitments support the financial integrity of Pepco and the role of the Commission in supervising it.

Finally, the Applicants have committed to not seek recovery of any acquisition premium or transaction costs in rates, and to not incur or assume any debt, including the provision of guarantees or collateral support, directly related to the Merger.

Together, these regulatory, organizational and financial commitments will support and further enhance the performance of Pepco's utility business units in meeting their public service obligations. In sum, the Applicants are putting in place a number of safeguards that appropriately address and mitigate both perceived and potential risks from the Merger – all of which will accrue to the benefits of Pepco's customers.

C. Assessment of the Economic Impacts of the Regulatory Commitments to the District of Columbia

37. Q. In addition to those measurable direct benefits and less measurable benefits to Pepco customers in the District of Columbia, are there other measurable economic benefits of the proposed Merger to the District of Columbia's economy and local community?

A. Yes. I examined these other measurable economic benefits through my IMPLAN analysis, to which I referred above.

38. Q. Before you describe the specific economic impacts of the different pieces of the Merger package, please summarize your assessment.

A. The Regulatory Commitments will result in substantial economic benefits for the District of Columbia's economy. These various benefits derive from the infusion of dollars and economic value into the local economy.

The *direct* benefits derive from two things: the Customer Investment Fund and the Enhanced Reliability Commitments affecting Pepco's distribution system. Both of these two Regulatory Commitments provide direct value to customers, but both also have larger impacts on the District's economy.

For example, as I described previously, the Customer Investment Fund will have different impacts on the local economy, depending upon how the Commission decides to deploy the dollars in the Customer Investment Fund. Without knowing how the Commission will choose to use that fund for the benefit of customers of Pepco, and without meaning to suggest that one particular use of the fund is preferable to others, I have modeled the impacts under three different sets of assumptions about potential use of the Customer Investment Fund's monies:

- In one scenario, I assumed that the Customer Investment Fund would be fully deployed in the form of a $52.95 credit on each distribution customer's bill, including residential and commercial and industrial customers. In this analysis, the money in the fund would go into the pockets of households, businesses and other organizations, as if it were new after-tax income to each of them.

- In another analysis, I assumed instead the money in the fund would be used to pay for energy efficiency measures. Spending the money this way would lead to the direct expenditure of the funds to hire contractors to install energy efficiency measures and to purchase more energy-efficient electricity-using equipment, and to lower electricity usage in general, resulting in savings on customers' electricity bills. My analysis assumed that such expenditures on energy efficiency would lower customers' purchases of electricity, but I only counted the avoided cost of commodity supply but not the distribution portion of customers' bills.[24] Thus, from a larger economic point of view, the use of the Customer Investment Fund for energy efficiency leads to expenditures on goods and services in the

[24] I made this assumption because of ratemaking policies which end up – over time – resetting distribution rates to ensure recovery of fixed costs of distribution service from all customers. In light of different investment recovery assumptions for commodity supply, I did not assume that lost revenues from lower sales resulting from energy efficiency would be made up by suppliers over time.

local economy, as well as to new after-tax income to consumers in the form of lower electricity bills.[25]

- I also explored the implications of using the Customer Investment Fund to provide direct credits on the electricity bills of low-income residential electricity customers alone. This impact shows up in the form of new after-tax income to such customers.

In each instance where I quantified benefits for customers in the form of direct impacts, there are also indirect and "induced" effects of the Customer Investment Fund and the Enhanced Reliability Commitments.

Indirect impacts flow from purchases of goods and services associated with the direct activity. An example might be the use of the Customer Investment Fund to invest in energy efficiency measures, with the direct impact being the original $14 million contribution from the Applicants, and the indirect impact being the purchase of more energy efficient appliances or equipment. Regarding

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[25] My analysis is conservative in that it does not track the impact of any avoided distribution or 'wires' charges, nor does it project the impact of energy efficiency on wholesale electricity prices (i.e., reflecting any reduction in such prices because demand is lower than it otherwise would be). I presumed that because of ratemaking for utility distribution service, loss of revenues from energy efficiency measures' impact on total sales would be addressed in subsequent rate case or revenue decoupling mechanisms. With respect to estimating the value to Pepco's customers and the economy associated with lower wholesale energy prices from investments in energy efficiency, I did not calculate the value of this indirect impact through the IMPLAN tool, in part because quantifying this impact involves more complicated modeling that would be required to simulate the specific dispatch of the PJM electric energy market with a lower demand curve and the consequent impact on lowering locational marginal clearing prices in wholesale markets. That said, my knowledge of and participation in prior studies leads me to conclude that the benefits of the Merger for customers that I did quantify are conservative because such impacts on wholesale electric energy clearing prices are not quantified in my analysis submitted here. See, for example, Paul J. Hibbard, and Susan F. Tierney, "Carbon Control and the Economy: Economic Impacts of RGGI's First Three Years." Electricity Journal, December 2011; and Paul J. Hibbard, Susan F. Tierney, Andrea M. Okie, Pavel G. Darling, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States: Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period, November 15, 2011.

the value of fewer or shorter outages, customers receive the direct value of avoided outages, and the indirect impacts reflect economic transactions between those residential and business customers that experience fewer/shorter outages and other businesses and economic actors with whom the customers can interact in the absence of the outage.

For both the Customer Investment Fund and the Enhanced Reliability Commitments, there are also "induced" effects associated with the direct and indirect economic impacts. These induced impacts result from the increased spending of workers who either get new income from the direct activity (e.g., the $52.95 in each household's or business' pocket) or are employed in the activities funded by the initial projects (e.g., the workers hired to install energy efficiency or reliability improvements on the distribution system). Together, these effects add new economic value to the local economy and generate tax revenues to governments in the District of Columbia.

39. Q. What are the results of your assessment?

A. Using IMPLAN and the core assumptions I previously described (and summarized in JOINT APPLICANTS (G)-4), I estimate that the Merger will result in: (a) 907 – 1,281 new jobs; (b) $95.4 million – $133.6 million in added value to the District of Columbia economy; and (c) incremental tax benefits (revenues) to the District of Columbia and local communities totaling $3.6 million

– $5.5 million dollars.[26] These results are summarized in Table SFT-5 (and in more detail in JOINT APPLICANTS (G)-5).

Table SFT-5
Economic Benefits Resulting from the Merger:
Applicants' Customer Investment Fund and Enhanced Reliability Commitments for Pepco in the District of Columbia:
Net Present Value (2014 $)

	Customer Investment Fund			Enhanced Reliability Commitments	Total Economic Benefits
	Assuming a $52.95 per Customer Credit on Each Customer's Utility Bill	Assuming the Funds are Spent on Energy Efficiency Measures	Assuming a Credit on Low-Income Residential Customers' Utility Bill		
Jobs	62	436	73	846	907 – 1,281
Value Added (NPV, 2014$)	$19.1 million	$57.3 million	$22.2 million	$76.3 million	$95.4 – $133.6 million
Incremental Tax Revenues (NPV, 2014$)	$0.5 million	$2.4 million	$0.6 million	$3.2 million	$3.6 – $5.5 million

As indicated, I have estimated economic impacts based on various scenarios reflecting different ways the Commission might decide to spend the money in the Customer Investment Fund, and the quantitative economic impacts vary according to these scenarios. I fully and respectfully recognize that there are intangible unquantified benefits that the Commission may want to take into consideration in determining how to use the Customer Investment Fund, and therefore my assumptions are illustrative and not intended to suggest a

[26] In general, I am rounding the numbers that were produced in my IMPLAN analyses. See JOINT APPLICANTS (G)-4 and (G)-5 for the back-up information for these estimates. District of Columbia taxes include personal income and corporate profit taxes, along with indirect personal and business taxes and dividends. Federal taxes are assumed to exit the District of Columbia economy.

recommendation as to the Commission's decision. I have thus described the results in terms of ranges of economic impacts, with a reasonable representation of the economic value of the Merger for the District of Columbia's economy.

40. Q. Are there any parts of the Regulatory Commitments that you did not include in the IMPLAN results reported above? If so, please explain.

A. Yes. To be conservative, there are several aspects of the Regulatory Commitments that I did not attempt to quantify. Many such commitments are described in the testimonies of Mr. Crane and Mr. Rigby, as well as in the testimony of Mr. Calvin Butler, Chief Executive Officer of Baltimore Gas and Electric Company.

For example, I did not include in my IMPLAN analysis any of the approximately $16.4 million that the Applicants have committed to provide to community and charitable organizations in the District of Columbia over the next 10 years. In 2013, for example, the direct economic value of such charitable contributions was approximately $1.6 million.

Also, I did not quantify the economic impacts associated with the Applicants' commitment to "local presence" – that is, retaining various business operations in places where they now exist before the Merger. The Regulatory Commitments include support for labor and other economic activity through maintaining the headquarters of the Company's system, with appropriate levels of senior management, and Pepco's local operational headquarters in the District of Columbia at Edison Place, as well as the Exelon Board, Committee or Subsidiary

Board meetings or Leadership meetings being held periodically in the District of Columbia.

Additionally, I did not quantify the economic benefits of the Applicants committing to retain existing supplier diversity programs, to honor all existing collective bargaining agreements, and to labor-related actions during at least the first two years following consummation of the Merger. The latter commitment would preclude, for several years, any net reduction (due to involuntary attrition as a result of the Merger integration process) in the employment levels at Pepco and would maintain compensation and benefits for current and former employees at Pepco that are at least as favorable in the aggregate as the compensation and benefits provided to the employees immediately before the Merger Agreement.

These various Regulatory Commitments provide real but unquantified benefits to the communities in which Pepco conducts its utility service.

III. CONCLUSIONS ON ECONOMIC IMPACTS OF THE PROPOSED MERGER

41. Q. Please summarize your overall conclusions.

A. Based on my review of the Application and the Regulatory Commitments in particular, along with my assessment of the economic impacts for Pepco customers and for the larger economy in the District of Columbia, I conclude that the proposed Merger will provide significant tangible and intangible benefits, including direct and traceable financial benefits, to customers of Pepco and to the economy of the District of Columbia.

42. Q. Does this conclude your testimony?

A. Yes.

S.F. Tierney Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants ________(G)-1

JOINT APPLICANTS (G)-1
CV of Susan F. Tierney, Ph.D.

Analysis Group

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Dr. Tierney, a Senior Advisor at Analysis Group, is an expert on energy economics, regulation and policy, particularly in the electric and gas industries. She has consulted to businesses, government, tribes, environmental groups, and other organizations on energy markets, economic and environmental regulation and strategy, and energy projects. Her expert witness and consulting services have involved market analyses, wholesale and retail market design, contract disputes, resource planning and procurements, regional transmission organizations, the siting of electric and gas infrastructure projects, electric system reliability, ratemaking for electric and gas utilities (including cost allocation, rate design, incentive ratemaking mechanisms), clean energy resources, climate change policy, and other environmental policy and regulation. She has participated as an expert in civil litigation cases, regulatory proceedings before state and federal agencies, and business consulting engagements.

Previously, she served as the Assistant Secretary for Policy at the U.S. Department of Energy in the Clinton Administration. She was the Secretary for Environmental Affairs in Massachusetts, Commissioner at the Massachusetts Department of Public Utilities, Chairman of the Board of the Massachusetts Water Resources Authority, and executive director of the Massachusetts Energy Facilities Siting Council.

Dr. Tierney has authored numerous articles and speaks frequently at industry conferences. She serves on a number of boards of directors and advisory committees, including chairing the External Advisory Council of the National Renewable Energy Laboratory (NREL) and the board of ClimateWorks Foundation. She is a director of the World Resources Institute, the Alliance to Save Energy, and the Energy Foundation. She is a member of the Bipartisan Policy Center's Energy Project, the National Petroleum Council (NPC), the China Sustainable Energy Program's Policy Advisory Council, and the Environmental Advisory Council of the New York Independent System Operator (NYISO). She co-chairs the NAESB Gas-Electric Harmonization Committee, the Bipartisan Policy Center's cyber security and the electric grid, is a member of the National Academy of Sciences panel on shale gas risk, and is co-lead author of the energy chapter of the National Climate Assessment. She chaired the Policy Subgroup of the NPC's study of the natural gas and oil resource base in North America, and served on the U.S. Secretary of Energy Advisory Board (and its Shale Gas Subcommittee). Previously, she chaired several non-profit organizations (the National Commission on Energy Policy; the Electricity Innovations Institute; and the Massachusetts Ocean Commission); was formerly a director of several companies (EnerNOC, Inc.; Evergreen Solar, Inc.; Ze-gen, Inc.; Catalytica Energy Systems Inc.), and several non-profit organizations (Clean Air Task Force; Clean Air – Cool Planet; the Electric Power Research Institute); and was a member of the Advisory Council of the New England Independent System Operator (ISO-NE) and the Massachusetts Renewable Energy Trust Advisory Council. She taught at the Department of Urban Studies and Planning at MIT and at the University of California at Irvine, and has lectured at Harvard University, Yale University, New York University, Tufts University, Northwestern University, and University of Michigan. She earned her Ph.D. and M.A. degrees in regional planning at Cornell University and her B.A. at Scripps College.

EDUCATION

1980	Ph.D. in Regional Planning, Public Policy, Cornell University, Ithaca, NY Dissertation: *Congressional policy making on energy policy issues*
1976	M.A. in Regional Planning, Public Policy, Cornell University, Ithaca, NY
1973	B.A. in Art History, Scripps College, Claremont, CA (studied political science at L'Institute d'Etudes Politiques, Paris, France)

PROFESSIONAL EXPERIENCE

2003-present	Analysis Group, Inc., Boston, MA *Senior Advisor (April 2014 – present); Managing Principal (July 2003 – March 2014)*
1999-2003	Lexecon, Inc., Cambridge, MA (formerly The Economics Resource Group, Inc.) *Senior Vice President*
1995-1999	Economics Resource Group, Inc., Cambridge, MA *Principal and Managing Consultant*
1993-1995	U.S. Department of Energy, Washington, DC *Assistant Secretary for Policy*
1991-1993	Commonwealth of Massachusetts, Executive Office of Environmental Affairs, Boston *Secretary of Environmental Affairs*
1988-1991	Commonwealth of Massachusetts, Department of Public Utilities, Boston, MA *Commissioner*
1984-1988	Commonwealth of Massachusetts, Energy Facilities Siting Council, Boston, MA *Executive Director*
1983-1984	Commonwealth of Massachusetts, Executive Office of Energy Resources, Boston, MA *Senior Economist*
1982-1983	Commonwealth of Massachusetts, Energy Facilities Siting Council, Boston, MA *Policy Analyst*
1982	National Academy of Sciences, Washington, DC *Researcher*
1978-1982	University of California at Irvine, Irvine, CA *Assistant Professor*

SELECTED CONSULTING EXPERIENCE

- **Various confidential engagements** involving power sales agreements, gas supply contracts, advisory services on gas and electric matters, transmission policy, oil market issues, water utility issues, and market power and monitoring issues.
- **Entergy Wholesale Commodities**
  Provided strategic advice on wholesale and retail market issues. (2013-ongoing)
- **Barr Foundation**

Prepared a report on the impacts of the Massachusetts Green Communities Act of 2008 on the Massachusetts economy. (2013-2014)

- **Five California Utilities (LADWP, PG&E, SCE, SDG&E, SMUD)**
  Served on the four-person expert Independent Advisory Panel for the third-party study of integration of renewable energy into California's Electric System ("Investigating a Higher Renewables Portfolio Standard in California"). (2013-2014)
- **State of Colorado**
  Prepared expert report on behalf of the three public utility commissioners in Colorado, in support of the complaint against them on implementing Colorado's renewable energy standard under alleged violations of interstate commerce clause. (2013-2014)
- **Energy Foundation**
  Wrote white paper on the implications for electric system reliability of the Environmental Protection Agency's implementation of its authority under Section 111(d) of the Clean Air Act, to regulate greenhouse gas emissions from existing power plants. (2013-2014)
- **Ambri (battery company)**
  Analyzed energy system issues related to integration of renewables on a military base. (2013-2014)
- **Advanced Energy Economy Institute**
  Facilitated workshop for state utility commissioners in Midwest states, on advanced energy technologies and related regulatory issues. (2013)
- **Environmental Defense Fund – North Carolina**
  Testified on energy efficiency program design issues. (2013)
- **Advanced Energy Economy Institute (with the New England Clean Energy Council and the New England Conference of Regulatory Utility Commissioners)**
  Supported workshop on advanced energy technologies and related regulatory issues. (2013)
- **Lawrence Berkeley National Laboratory Energy Program**
  Support on regulatory issues at workshop for the New Jersey Board of Public Utilities on smart grid issues. (2013)
- **Advanced Energy Economy Ohio**
  Testimony before the Ohio Senate Public Utilities Committee in support of the Ohio Energy Efficiency Resource Standard. (2013)
- **Pepco Holdings Inc., and its operating affiliates, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company**
  Testimony in support of appropriate incentives for investment in electric transmission. (2013)
- **Baltimore Gas and Electric Company**
  Testimony in support of appropriate incentives for investment in electric transmission. (2013)
- **Advanced Energy Economy Institute**
  Survey of CEOs of advanced energy companies doing business in California, with regard to the state's energy and environmental policies. (2012-2013)
- **NSTAR and Cape Wind**
  Testimony in support of the long-term power purchase agreement of NSTAR and Cape Wind. (2012)
- **Energy Foundation**
  Strategic planning for the China Sustainable Energy Program. (2012)
- **Pacific Gas & Electric Company**
  Testimony on ratemaking issues for PG&E's proposed pipeline safety enhancement plan. (2012)
- **COMPETE Coalition**
  Testimony on energy efficiency as part of the performance of state and wholesale electric markets in New Jersey. (2011)
- **Compressed Air Energy Storage Company**

Confidential engagement to analyze regional wholesale markets for baseload and renewable energy power generation. (2011)

- **Merck Family Foundation**
  Analysis of the economic impacts of the funds collected through the auction of allowances under the Regional Greenhouse Gas Initiative. (2011)
- **American Clean Skies Foundation Corporation**
  Analysis of the reliability and air emission issues associated with potential retirement of the Potomac River Generating Station. (2011)
- **Colorado Public Utilities Commission**
  Analysis of the Colorado solar photovoltaic incentive program. (2011)
- **Exelon Corporation and Constellation Energy (Baltimore Gas & Electric)**
  Analysis of the economic impacts on the Maryland economy associated with the proposed clean-energy commitments tied to the proposed merger of Exelon and Constellation Energy. (2011-2012)
- **New England Power Generators Association**
  Analysis of competition issues associated with the proposed merger of Northeast Utilities and NSTAR. (2011)
- **Dominion Generation**
  Analysis of proposed state tax on output from in-state power generation. (2011)
- **Exelon Corporation and Clean Energy Group**
  Analysis of electric industry issues involved in responding to the U.S. Environmental Protection Agency's air emission regulations. (2010-present)
- **Major electric distribution company and independent power producer**
  Analysis of the net benefits of retiring a set of generating units, and replacing it with a long-term contract to provide power from a gas-fired power plant and biomass power plant. Modeled locational energy prices, capacity prices, and revenue streams in the region. (2010)
- **Major electric utility company**
  Analysis of changing fuel-market conditions affecting the value of gas-fired power generation in the context of litigation. (2010)
- **Commonwealth Edison Company**
  Analysis of the ratemaking issues for a electric distribution utility with respect to energy efficiency program effects in Illinois. (2010-2011)
- **National Grid – Massachusetts electric distribution companies**
  Analysis of the market for and other attributes of the long-term contract for power from the Cape Wind project. (2010)
- **Spectra Energy (with the Interstate Natural Gas Association of America)**
  Analysis of the markets for natural gas, and analysis of the implications of the U.S. Environmental Protection Agency's Advanced Notice of Proposed Rulemaking on PCBs. (2010-2011)
- **Renewable energy company**
  Analysis of transmission access, planning, cost allocation and siting conditions in regions through the U.S. (2010-present)
- **Indian tribe in MidWest**
  Analysis of the value of an oil pipeline right-of-way. (2010)
- **Dominion Generation**
  Analysis of the proposed legislation in Connecticut to establish a windfall profits tax on all generating assets located in the state. (2010)
- **Transmission consortium**
  Analysis of cost-allocation models for an interstate transmission project involving transmission utilities and merchant transmission companies. (2009-2010)

- **Massachusetts renewable energy trust**
  Analysis of transmission-related models and considerations for the development of offshore renewable energy. (2009)
- **Major electric utility**
  Development of business models and approaches for deploying energy efficiency within the context of the American Climate and Energy Security Act framework. (2009)
- **Major industrial electricity consumer**
  Assistance in analyzing the implications of the American Climate and Energy Security Act for the company, in light of impacts on energy prices and trade considerations. (2009)
- **National Grid**
  Assistance in developing a revenue decoupling mechanism for retail distribution service, and providing expert witness assistance in electric and natural gas distribution rate cases in Massachusetts, Rhode Island, New York and New Hampshire. (2009-2011)
- **Sandia Pueblo**
  Assistance in valuing a transmission corridor on tribal reservation land. (2008-present)
- **Major electric and gas company**
  Analytic and strategic support for company's development of a business plan for energy efficiency and other energy-related investments on the customer side of the meter. (2008)
- **AEP Transmission**
  Prepared a white paper on the design and cost allocation framework for a high-voltage transmission system designed to support renewable and other resources. (2008)
- **Reliant**
  Prepared study assessing competition in the wholesale and retail electricity markets in ERCOT. (2008)
- **Major environmental organization**
  Analytic and strategic support for utility ratemaking policies for advancing energy efficiency in many states. (2008-present)
- **New York Independent System Operator**
  Supported strategic planning and assessment for the Board of Directors. (2008-2010)
- **Commonwealth Edison Company**
  Provided testimony on ratemaking policy issues relating to regulatory lag. (2008)
- **Energy Association of Pennsylvania (EGA)**
  Analysis of proposed legislation to cap retail electricity rates in Pennsylvania after the expiration of rate caps. (2008)
- **National Association of Regulatory Utility Commissioners (NARUC)**
  Preparing study on best practices relating to state regulatory agency policies and utility practices on competitive procurement of resources to serve retail electricity customers. (2007)
- **KeySpan/Boston Gas**
  Analysis of the implications of utility ratemaking for valuation of utility assets for property taxation purposes. (2008)
- **Electric company**
  Analysis of state's retail and wholesale power market structure. (2008)
- **Electric company**
  Preparation of expert report on electric industry structure in the 1990s and 2000s. (2007-2008)
- **Major electric company**
  Analytic support for company's development of strategic plan for company-wide greenhouse gas reduction commitments. (2008)
- **Sierra Pacific Power Company**

Provided testimony on policy issues relating to the use of historic, future, and hybrid test years in state utility rate cases. (2007-2008)

- **Harvard University**
  Provided strategic assistance relating to regulatory issues affecting the planning and design of Harvard's "green campus" development in Allston Landing. (2007-2008)

- **Public Service Gas & Electric Company of New Jersey (PSEG)**
  Provided assistance in facilitating the development of a policy to address "leakage" of greenhouse gas emissions associated with the adoption of a cap-and-trade program in various Northeast states and the interstate sales of electricity in various Northeast/MidAtlantic power markets. (2007)

- **Electric Power Supply Association**
  Prepared white paper on economic, environmental & regulatory trends in the electric industry (2007).

- **Sempra Energy Company – San Diego Gas & Electric Company and SoCalGas Company**
  Provided testimony on policy issues relating to the provision of financial incentives to electric and gas utilities for the successful provision of energy efficiency programs. (2007)

- **PECO Energy Company**
  Provided advice on various economic and policy issues relating to electric industry restructuring policy. (2007)

  Provided testimony on issues relating to the market for alternative energy credits and the proposal of PECO to voluntarily solicit, procure and bank alternative energy credits. (2007)

- **Commonwealth Edison Company**
  Provided testimony on issues relating to the relationship of auctions for wholesale supply for basic service customers and alternative proposals for utility resource procurement. (2007)

- **ISO New England**
  Assisting Regional Transmission Organization in scenario planning process examining various future technology mixes for New England's electric system. (2006-2007)

- **PJM**
  Preparing report on market monitoring functions performed under various federal regulatory agencies with responsibility to oversee electricity and energy markets (i.e., the Federal Energy Regulatory Commission and the Commodities Futures Trading Commission). (2006-2007)

- **Major Industrial and Power Plant Company**
  Assisted company (located outside of New England) in analyzing market and negotiating the price and other terms and conditions for long-term gas supply (2006-2007). Assisted company in valuing a power plant asset. (2007)

- **State of North Carolina**
  Provided expert witness services on electric utility economics and regulatory issues, on behalf of the North Carolina Attorney General in a nuisance lawsuit to require the Tennessee Valley Authority to put in place air pollution control equipment on coal-fired power plants in TVA's system. (2006-2008)

- **Major Regional Transmission Organization**
  Performed analysis of market conditions and trends, and benchmarking market rules and reliability performance with other comparable organizations – in support of RTO's strategic planning process. (2006-2007)

- **Special LNG Committee, Commonwealth of Massachusetts**
  Prepared report on the need for natural gas and liquefied natural gas in the Northeast, the need for LNG facilities, the role of government in the LNG facility siting process, and other issues relating to LNG proposals in the Commonwealth. Provided on *pro-bono* basis to the Commonwealth. (2006)

- **Ute Indian Tribe of the Uintah and Ouray Reservation**
  Prepared a report on economic and policy issues relating to use of tribal lands for energy rights-of-way, as called for in Section 1813 of the Energy Policy Act of 2005. (2006)

- **New York ISO**
  Prepared white paper on fuel diversity issues in the New York market. (2008)

  Prepared white papers on long-term contracting issues in states with restructured electric industries, and on the economic foundations for single-clearing-price markets versus pay-as-bid markets. (2007)

Performed economic benefit/cost study of the introduction of competition into the wholesale electric market in the region. (2006-2007)

- **Commonwealth Edison Company**
  Provided testimony on appropriate ratemaking principles for recovery of pension-related costs in proceeding to set rates to go into effect following the transition period. (2006)
- **Commonwealth Edison Company**
  Provided testimony on economic principles associated with single-price auction design versus pay-as-bid auction design, for the procurement of wholesale power supplies to meet the needs of retail all-requirements customers. (2006)
- **Exelon Corporation**
  Provided analysis of designs of mandatory carbon control policies. (2005-2007)
- **Sonosky, Chambers, Sachse, Endreson & Perry, LLP, on behalf of various Indian Tribes**
  Provided analysis in support of comments filed with the Departments of Interior and Energy with respect to the study of energy rights of way on tribal land which was called for in Section 1813 of the Energy Policy Act of 2005. (2005-2006)

  Provided analysis in support of various tribal negotiations with energy companies with respect to valuation of energy rights of way on tribal reservation lands. (2007)
- **Electric utility company**
  Performed independent evaluator services in procurement for power resources. (2005-2006)
- **Power Generation Company**
  Provided analysis of product market development in MidWest and Eastern RTOs. (2005)
- **New England Energy Alliance**
  Prepared a white paper on energy infrastructure needs in the New England states. (2005)
- **Committee on Regional Electric Power Cooperation (of the Western Interstate Energy Board)**
  Provides research and advising with respect to market monitoring and assessment for the Western wholesale electric markets. (2005-2007)
- **Southern California Edison Company**
  Provided Independent Evaluator services for a competitive procurement of new long-term generation resources and renewable resources. (2005)
- **LNG / Interstate Gas Pipeline project – Duke Energy/Excelerate project**
  Prepared regional market study for the project proposed for Massachusetts. (2004-2005)
- **Electric Generating Company**
  In a contract dispute, provided expert witness services relating to whether changes in a region's wholesale power market rules nullified a power sales agreement. (2004-2006)
- **Louisville Gas & Electric and Kentucky Utilities**
  For two vertically integrated electric companies, provided expert witness services in a state investigation of which regional transmission approach satisfies state policy objectives. (2004)
- **Independent Generating Company**
  For a power company owned by commercial lenders in a Northeast power market, provided consulting services to monitor state regulatory policies and actions with respect to utility regulation and environmental regulation, and legislation affecting power plants. (2004)
- **Major Electric and Gas Company**
  Performed confidential study of the benefits, costs and current conditions in certain wholesale and retail electric power markets. (2004-2005)
- **Regional Transmission Organization**
  For a confidential project, analyzed market monitoring and mitigation approaches. (2004-2005)

- **Major Commercial Bank**
  For a confidential project, advise with regard to electric industry restructuring and profitability of large energy marketer and trading organization. (2004-2005)
- **Consumer Energy Council of America**
  For a group of electric industry market participants, regulators, and interest groups, prepared white papers on the need for transmission enhancements in U.S. power markets. (2004)
- **Retail electric company**
  Provides confidential analysis of business models and regulation approaches for providing retail electric service in the state. (2004)
- **Independent system operator**
  Provided confidential analysis and research on aligning retail and wholesale market policies. (2004)
- **California State attorney general**
  Provided expert witness services with regard to state resource adequacy & planning practices. (2004)
- **Pacific Gas & Electric Company**
  Provided expert witness services relating to the public benefits of the settlement between PG&E and the California Public Utility Commission, to enable PG&E to emerge from bankruptcy. (2003)
- **Independent power company**
  Provided consulting advice on economics of compliance strategies for air and water permits. (2003)
- **Major public utility company**
  Provided expert advisory services to a buyer of power supplies relating to the pricing and other terms for a long-term purchase power agreement. (2003)
- **Duke Power**
  Provided expert advisory services relating to rate-making and other regulatory practices. (2003)
- **Exelon Generation**
  Provided strategic advice and analytic services relating to market conditions affecting the client's generating assets in New England. (2003)
- **Entergy Services Inc.**
  Provides services as the independent monitor of Entergy's Fall 2002, Spring 2003 and Fall 2003 Requests for Proposals for Supply-Side Resources. (2002-2005)
- **Power generation company in New England**
  Provided expert testimony in contract dispute regarding allocation of uplift costs in an agreement concerning the supply of wholesale power for standard offer service. (2002)
- **Connecticut Light and Power Company**
  Provided expert testimony in contract dispute regarding allocation of congestion costs in an agreement concerning the supply of wholesale power for standard offer service. (2002-2003)
- **Ocean State Power**
  Provided arbitration services in a dispute regarding a gas purchase contract between Ocean State Power and ProGas Ltd. (2002-2003)
- **Regional independent system operator**
  Provided strategic advice on regional transmission organization strategy. (2002)
- **PJM Interconnection**
  Provided advice to the appointed mediator as part of the Alternative Dispute Resolution process, in a dispute involving PJM and a market participant. (2002)
- **Duke Energy Corporation**
  Provided analysis on strategic issues in gas and electric regulatory policy for Duke Energy's corporate office, including with regard to code of conduct issues, wholesale competition, regional transmission organization policy. (2001-2002)

- **Pacific Gas and Electric Corporation**
  Provided expert witness testimony in proceedings of the Federal Energy Regulatory Commission on public benefits of the proposed restructuring of PG&E assets as part of its emergence from bankruptcy. (2001-2002)

- **Massachusetts Renewables Trust**
  Provided assistance in support of the Trust's renewables and power quality program. (2001-2002)

- **Major electric holding company**
  Prepared an analysis of the regulatory policies for reviewing merger applications in states where potential merger candidates are located. (2001)

- **Western Massachusetts Electric Company**
  Provided expert testimony in contract disputes regarding allocation of congestion costs in agreements concerning the supply of wholesale power for standard offer service. (2001-2002)

- **The Energy Foundation**
  Researched and wrote a white paper on California's process for permitting new power plants. (2001)

- **Cross-Sound Cable Company**
  Provided expert testimony regarding public benefits of proposal to construct merchant transmission facility across Long Island Sound. (2001-2002)

- **Major independent power company**
  Provides expert witness support in litigation surrounding power plant development project, involving viability of project's environmental and siting permitting. (2001-2004)

- **MASSPOWER Inc.**
  Mediator in a contract dispute involving pricing of power purchases. (2001)

- **NRG Energy and Dynegy**
  Provided expert witness support in regulatory proceeding to review these companies' acquisition of power plants being divested by Sierra Pacific and Nevada Power. (2001)

- **Occidental Chemical Corporation**
  Provided expert witness support and economic analysis of a major electric utility's transmission policies and practices, and review of the proposed RTO. (2000)

- **PP&L Global**
  Provided economic and environmental analysis and expert witness support for proposal to build the Kings Park Energy power plant in Long Island, New York. (2000)

- **Calpine Corporation**
  Provided economic and environmental analysis and expert witness support for proposal to build the Wawayanda power project in Rockland County, New York. (2000)

  Provided environmental analysis and expert witness support for proposal to build the Towantic power plant in Oxford, Connecticut. (2001)

- **American National Power, Calpine, El Paso, NRG Energy, Sithe, Southern Energy**
  Provided support for the development of a proposal for a Regional Transmission Organization for New England. (2000-2001)

- **Duke Energy/Maritimes and Northeast Pipeline**
  Provided expert reports on the market and environmental impacts of new natural gas infrastructure and supply in New England and the public benefits of the Maritimes and Northeast Phase III and Hubline project. (2000-2003)

- **Arkansas Electric Distribution Cooperatives and Arkansas Electric Cooperative Corporation**
  Provided expert witness support and analysis on economic and public policy issues associated with various aspects of wholesale and retail competition in Arkansas. (2000-2001)

- **TransÉnergie U.S.**
  Provided expert testimony regarding public benefits of proposal to construct merchant transmission facility. (2000-2001)

- **Conectiv**
  Provided strategic wholesale market analysis and support for procurement of supplies for distribution utility company's provision of Basic Generation Services to retail customers. (2000)

- **SCS Energy Corp. – Astoria Energy**
  Provided economic and environmental analysis and expert witness support for proposal to build new power plant in New York City. (2000-2001)

- **HEFA Power Options**
  Provided strategic advice regarding wholesale power market for retail buyers' group. (2000-2003)

- **Major real estate development company**
  Provided strategic support for configuration of electric and gas infrastructure for large regional mixed-use development project. (2000-2001)

- **Investment company**
  Provided strategic advice to investment company with regard to potential investment in major electric generating equipment manufacturing company. (2000)

- **Major independent power company**
  Provided economic and environmental support for company's application to construct a merchant power plant in Florida. (2000)

- **Major railroad company**
  Provided expert witness support on economic and regulatory policy issues for railroad in state regulatory proceeding on a proposed utility merger. (2000)

- **Coalition of Wireless Telecommunications Carriers**
  Prepared an expert report on economic benefits of wireless telecommunications. (2000)

- **Major brownfield property developer**
  Provided valuation of property to be developed as site for new electric generating facility. (2000)

- **Fitchburg Gas and Electric Company**
  Provided litigation support for a gas and electric company on rate design policy. (2000)

- **Consortium of electric companies**
  Provided economic analysis, contract review, and litigation support for a consortium of electric companies with power purchase agreements with PURPA projects. (1999)

- **FirstEnergy Corp.**
  Provided expert witness support regarding generation asset valuation and the impacts of a new electric industry restructuring law on the company. (1999-2000)

- **Ozone Attainment Coalition**
  Provided strategic analysis and advice on electric system reliability issues relating to electric companies' implementation of 2003 NOx requirements issued by the U.S. EPA. (1999)

- **Municipal electric department**
  Provided expert witness services and analysis of the economics and need for a new natural gas pipeline proposed to serve an existing electric power plant in Massachusetts. (1998-2001)

- **Seneca Nation**
  Provided expert analysis and strategic advice regarding the value of transmission rights of way, in a dispute with an electric utility company. (1998-2000)

- **Major cable company**
  Provided strategic advice in a series of regulatory and court cases involving inter-affiliate transactions of electric utility company entering into competitive telecommunications and cable markets. (1998)

- **Major electric utility company**
  Provided expert witness support regarding structural changes in the electric industry, in litigation pertaining to the company's restructuring plans. (1998-1999)

- **Sithe Energies, Inc.**
  Provided strategic advice and regulatory support on a variety of issues (market analysis, transmission and ISO issues, federal and state market rules, legislation, siting, environmental strategy) relating to the company's participation in the New England, New York, and PJM markets. (1997-2003**)**

  Provided transition assistance to the company in its acquisition and integration of approximately 2,000 MW of existing fossil fuel generation from Boston Edison Company. (1997-1998)

  Provided transition assistance to the company in its acquisition and integration of approximately 4,100 MW of existing fossil and hydroelectric generation capacity from GPU Genco. (1998-1999)

  Provided support for the company's participation in electricity product markets structured by NEPOOL and operated by the Independent System Operator-New England, the New York power pool and the New York ISO, and PJM. (1997-2002)

  Provided strategic project development advice and expert witness support for the company's applications to construct three natural gas merchant power plants (totaling 2865 megawatts) in Everett, Weymouth, and Medway, Massachusetts. (1998-2001)

  Provided strategic guidance and regulatory support regarding design of air quality improvement plan for existing fossil units at Mystic Station. (1998-2001)

  Provided strategic guidance regarding company's natural gas-fired merchant power plant development projects in Ontario, Canada. (2000-2001)

- **Natural Resources Canada**
  Prepared a white paper on the implications for electric system reliability in Canada that are associated with restructuring the electric industry in the United States. (1999)

- **Cummins Engine Company, Inc.**
  Provided strategic analysis on implications of national energy and environmental policies for the Company's long-term business opportunities. (1999)

- **Electric utility company**
  Provided advice and regulatory support with regard to the economics and prudency of an existing long-term power purchase agreement. (1998)

- **National Association of Regulatory Utility Commissioners (NARUC)**
  Assisted the Executive Director and NARUC leadership in updating its strategic plan and in preparing a business plan for its implementation. (1998)

- **State energy office**
  Assisted the office in analyzing options for supporting renewable resource development in the state and in designing a market-based strategy to implement a new legislative mandate for a "renewables portfolio standard." (1997-1998)

- **U.S. Generating Company (now PG&E Generating Company)**
  Provided analysis of the economic, reliability, and environmental benefits to the host state and region of a new merchant power generation facility: the 360-megawatt Millennium project in Massachusetts. Provided expert witness testimony on the results of this analysis to the Massachusetts Energy Facility Siting Board. (1996-1997)

  Provided analysis of the economic, reliability, and environmental benefits of a new merchant power generation facility: the 792-megawatt Lake Road Generating Project in Connecticut. Provided expert witness testimony on the need for this project to the Connecticut Siting Board. (1997-1998)

- **Pennsylvania Power & Light Company**
  Provided strategic guidance, economic and policy analysis, and regulatory support for electric utility company as it developed and proposed its plan for restructuring its company for retail competition. Issues and tasks included electricity market price estimation, rate design, revenue analysis, consumer protection, corporate structure, and regulatory strategy. Provided expert witness testimony on rate design policy issues. (1996-1998)

- **Major diversified electric equipment company**
  Provided strategic advice and analysis on market opportunities and risk in various regions of the U.S. electric industry, under numerous restructuring scenarios. (1996-1997)

- **Major nationwide electricity consumer**
  Conducted analysis of buying options and strategies for acquisition of electricity services in states with customer choice in retail generation markets. Analysis included review and comparison of eight states' implementation of customer choice, from the perspective of how retail rate and function are unbundled, how the commercial and reliability functions are structured in the regional generation market, and how the customer should approach the market to competitively procure power across various states. (1997)

- **National Council on Competition in the Electric Industry**
  Prepared a Briefing Paper on Regional Issues in Electric Industry Restructuring, for the NCCEI—a joint project of the National Association of Regulatory Utility Commissioners, the National Conference of State Legislatures, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. Analyzed regional issues, including electric system reliability, transmission access and siting, environmental protection, market power, interstate reciprocity in retail access policies, and regulation of multi-state electric utility companies. (1997)

- **Major western coal company**
  Analysis of western states' electric industry restructuring policies and market prices for power in various states within the Western Systems Coordinating Council area. (1996-1997)

- **Major gas pipeline company**
  Provided analysis of market structures and prices for generation and delivery services in electric service territories where the gas pipeline would locate facilities that use electricity. (1997)

- **Major electric supply company**
  Provided analysis of regional electricity market conditions to support this company's analysis of the value of various utility assets that were being divested as part of an electric utility company's corporate restructuring. (1997)

- **Massachusetts Division of Energy Resources**
  Analyzed Boston Gas Company's proposal for unbundling its retail service, its proposal for performance-based rates, and its plan for departing the merchant function. Provided analytic, policy and negotiation support on gas industry restructuring issues in a variety of cases. (1996-1998)

- **Massachusetts Division of Energy Resources**
  Assisted the state's energy office in developing policies for establishing a statewide fund to support renewable resource development as part of the state's electric industry restructuring plan. Provided analytic support to the energy office as it participated in a working group of stakeholders attempting to reach consensus on the institutional design of such a renewables fund. Drafted legislative language to create the fund and the non-bypassable charge on distribution service in the state. (1997)

- **Massachusetts Water Resources Authority Advisory Board**
  Analyzed opportunities for the MWRA, a public authority with major energy-using and -producing assets, to position itself beneficially as a participant in a restructured retail electricity market in New England. (1996-1997).

- **Coalition of marketers and independent power producers**
  Analyzed state public utility commission proposed rules for restructuring the electric industry, from the point of view of whether the proposed structure would assure a workably competitive market. Examined the transmission owners' proposal for an independent system operator. (1996-1997)

- **Major independent power producer**
  Analyzed market opportunities and risks for merchant plant development in a U.S. region. (1996)

- **Major independent power producer**
  Analyzed the expected market price of power in two regions of the U.S. electricity markets. Presented results to company board of directors. (1996)

- **MCI, Inc.**
  Provided strategic regulatory advice in local competition proceeding before a state public utility commission. Provided testimony on local competition policy issues in public utility commission proceedings in Massachusetts and New York. (1996)

- **Group of municipal electric companies in New York State**
  Provided expert witness testimony on cost allocation issues in court litigation on wholesale power contracts. (1996)

- **Intercontinental Energy Corporation**
  Provided strategic guidance, analytic support, and regulatory support for the company, a major independent power producer, as it developed its position in the state's electric industry restructuring proceeding. Issues involved regional industry structure (including independent system operator proposals), stranded cost recovery policy, stranded cost calculation methodologies, horizontal and vertical market power issues, environmental protection, and securitization. Provided expert witness testimony in state retail restructuring proceedings in Massachusetts and New Jersey. (1995-1997).

- **Nextel Communications**
  Provided economic and policy analysis on barriers to entry in the local commercial mobile radio service market in region. Provided expert witness testimony before the Massachusetts Department of Public Utilities. (1995-1998)

- **Arizona Public Service Company**
  Provided expert witness testimony on regulatory reforms necessary to align traditional existing utility planning proceedings with competitive retail markets as being proposed in the state. (1995)

TESTIMONY ON BEHALF OF CLIENTS

Many confidential expert reports, testimonies, declarations, affidavits, and depositions in confidential arbitrations and mediations.

- **On her own behalf**
  Before the Oregon State Legislature's House Interim Committee on Revenue, Senate Interim Committee on Finance and Revenue, on "Consideration of the Feasibility and Implications of a Clean Air Tax or Fee in Oregon: Implementing Greenhouse Gas Emission Reduction Policies – Experience from Other States," January 15-16, 2014.

- **On her own behalf**
  Before the U.S. House of Representatives Energy and Commerce Subcommittee on Energy and Power, "Hearing on EPA's Proposed GHG Standards for New Power Plants and H.R. _, Whitfield-Manchin Legislation," November 14, 2013**.**

- **Joshua Epel, James Tarpey, and Pamela Patto, et. al.**
  Before the U.S. District Court of the State of Colorado, on behalf of Joshua Epel, James Tarpey, and Pamela Patton (commissioners of the Colorado Public Utilities Commission), and Environment Colorado, Conservation Colorado Education Fund, Sierra Club, The Wilderness Society, Solar Energy Industries Association, and Interwest Energy Alliance, in re: *American Tradition Institute and Rod Lueck, v. Epel at al*., Civil Action Number 11-cv-00859-WJM-BMB, expert report, November 7, 2013.

- **On her own behalf**
  Before the Federal Energy Regulatory Commission, in the Matters of Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators," Docket No. AD13-7-000, re: considerations for the future, September 9, 2013.

- **Environmental Defense Fund and North Carolina Sustainable Energy Association**
  Before the Public Utilities Commission of North Carolina, Docket E-7, SUB 1032, August 7, 2013.

- **Advanced Energy Economy Ohio**
  Before the Ohio Senate Public Utilities Committee in support of the Ohio Energy Efficiency Resource Standard, April 9, 2013.

- **Pepco Holdings, Inc., and its operating affiliates, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company**
  Before the Federal Energy Regulatory Commission, in Delaware Division of Public Advocate, *et. al*., v. Baltimore Gas and Electric Company and Pepco Holdings Inc., Docket No. EL13-48-000, April 3, 2013.

- **Baltimore Gas and Electric Company**
  Before the Federal Energy Regulatory Commission, in Delaware Division of Public Advocate, *et. al*., v. Baltimore Gas and Electric Company and Pepco Holdings Inc., Docket No. EL13-48-000, April 3, 2013.

- **NSTAR Electric Company and Cape Wind LLC**
  Before the Massachusetts Department of Public Utilities, in the Petition of NSTAR Electric Company for Approval

of a Proposed Long-Term Contract for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, §83, Prefiled Direct Testimony, March 30, 2012; testimony under cross-examination, August 2, 2012.

- **Pacific Gas and Electric Company**
  Before the California Public Utilities Commission, in the Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms, Rulemaking 11-02-019, Rebuttal Testimony filed on February 28, 2012; testimony under cross-examination, March 20, 2012.

- **COMPETE Coalition**
  Before the New Jersey Board of Public Utilities, In the Matter, In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, Docket No. EO11050309, October 14, 2011.

- **On her own behalf**
  Before the U.S. House Energy and Commerce Committee, Subcommittee on Energy and Power, EPA Regulations and Electric System Reliability, September 14, 2011.

- **On her own behalf**
  Before the U.S. Senate Environment and Public Works Committee, Subcommittee on Clean Air and Nuclear Safety, June 30, 2011, Oversight Hearing: Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

- **Exelon Corporation and Constellation Energy Group**
  Before the *Maryland Public Service Commission*, In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Case No. 9271, prefiled direct testimony (May 25, 2011); rebuttal testimony (October 12, 2011), supplemental testimony (December 15, 2011), testimony under cross-examination (November 10, 2011, January 25, 2012).

- **New England Power Generators Association**
  Before the *Massachusetts Public Utilities Commission, In the Matter of the Joint Petition for Approval of Merger [of Northeast Utilities and NSTAR] Pursuant to G.L. c. 164* , § 96, Docket D.P.U. 10-170, prefiled direct testimony (May 20, 2011); testimony under cross-examination (July 15 and 18, 2011).

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Investigation of Proposed General Increase in Electric Rates of Commonwealth Edison Company, Docket No. 10-0467, ComEd Exhibit 13.0, prefiled direct testimony (filed June 30, 2010); rebuttal testimony (filed November 22, 2010); surrebuttal testimony (filed January 2, 2011), testimony under cross-examination (January 18, 2011).

- **National Grid: Massachusetts Electric Company and Nantucket Electric Company**
  Before the *Massachusetts Department of Public Utilities*, Investigation as to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval by the Department of Public Utilities of two long-term contracts to purchase wind power and renewable energy certificates, pursuant to G.L. c. 169, § 83 and 220 C.M.R. § 17.00 et seq. – Docket D.P.U. 10-54 (the Cape Wind contract proceeding), prefiled direct testimony (filed June 4, 2010), rebuttal testimony (filed September 1, 2010), testimony under cross examination (September 8, 13, 14, 23, 24, 2010).

- **National Grid: Boston Gas Company, Essex Gas Company, Colonial Gas Company**
  Before the *Massachusetts Department of Public Utilities*, Investigation as to the Propriety of Proposed Tariff Changes, Docket No. D.P.U. 10-55, prefiled direct testimony (filed April 16, 2010); testified under cross-examination, June 28-29, 2010.

- **National Grid: EnergyNorth Natural Gas, Inc., d/b/a National Grid NH**
  Before the *New Hampshire Public Utilities Commission*, Investigation as to the Propriety of Proposed Natural Gas Tariff Changes, Docket DG 10-017, prefiled direct testimony (filed February 26, 2010).

- **National Grid: Niagara Mohawk Power Corporation**
  Before the *New York Public Service Commission*, Investigation as to the Propriety of Proposed Electric Tariff Changes, Docket No. 10-E-0050, prefiled direct testimony (filed January 29, 2009), rebuttal testimony (filed August 2010).

- **National Grid: Narragansett Electric Company**
  Before the *Rhode Island Public Utilities Commission,* Investigation as to the Propriety of Proposed Tariff Changes, Docket No. R.I.P.U.C. 4065, prefiled direct testimony (filed June 1, 2009; testimony under cross-examination, November 4, 2009).

- **National Grid: Massachusetts Electric Company and Nantucket Electric Company**
  Before the *Massachusetts Department of Public Utilities*, Investigation as to the Propriety of Proposed Tariff Changes, Docket No. D.P.U. 09-39, prefiled direct testimony (filed May 15, 2009; testimony under cross-examination, August 7 and 25, 2009, and September 8, 2009).

- **Amerada Hess Corp., et al.**
  Before the District Court of the United States for the Southern District of New York, on behalf of Amerada Hess Corp., et al., in *City of New York v. Amerada Hess Corp. et al.*, Case No. 1:00-1898, testimony in deposition, May 12, 2009.

- **State of North Carolina**
  Before the District Court of the United States for the Western District of North Carolina, on behalf of North Carolina in *State of North Carolina, ex rel. Roy Cooper, Attorney General, v. Tennessee Valley Authority*, Case No. 1:06CV20, testimony in deposition, May 17, 2007; testimony at July 22, 2008.

- **KeySpan Energy Delivery (National Grid)**
  Before the Massachusetts Appellate Tax Board, Boston Gas Company, d/b/a KeySpan Energy Delivery New England v. City of Boston, Docket No. F275055-F275056 (FY 2004), F279207-F279208 (FY 2005), F284088-F286194 (FY 2006), testimony and cross-examination, May 20-21, 28, June 4, 2008.

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Investigation of Proposed General Increase in Electric Rates of Commonwealth Edison Company, Docket No. 07-0566, ComEd Exhibit 18.0, prefiled rebuttal testimony (filed April 12, 2008).

- **Sierra Pacific Power Company**
  Before the Public Utilities Commission of Nevada, In the Matter of the Application of Sierra Pacific Power, filed pursuant to NRS 704.110(3), for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement, Docket No. 07-12 (filed December 3, 2007), Prefiled Direct Testimony; cross examination, April 17-18, 2008.

- **Amerada Hess Corp., et al.**
  Before the District Court of the United States for the Southern District of New York, on behalf of Amerada Hess Corp., et al., in *County of Suffolk and Suffolk County Water Authority v. Amerada Hess Corp. et al.*, Case No. 1:00-1898, testimony filed October 1, 2007.

- **Sempra Energy Company – San Diego Gas & Electric Company and SoCalGas Company**
  Before the *California Public Utility Commission*, Order Instituting Rulemaking to Examine the Commission's post-2005 Energy Efficiency Policies, Programs, Evaluation, Measurement and Verification and Related Issues, Rulemaking Docket 06-04-010 (Filed April 13, 2006), testimony filed May 3, 2007, cross examination, May 29, 2007.

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Investigation of Rider CPP of Commonwealth Edison Company, and Rider MV of Central Illinois Light Company d/b/a AmerenCILCO, of Central Illinois Public Service Company d/b/a/ AmerenCIPS, and of Illinois Power Company d/b/a Ameren IP, pursuant to Commission Orders regarding the Illinois Auction, Docket No. 06-0800, testimony filed April 6, 2007; cross-examination, April 24, 2007.

- **PECO Energy Company**
  Before the *Pennsylvania Public Utility Commission*, Petition of PECO for Approval of (1) a Process to Procure Alternative Energy Credits During the AEPS Banking Period, and (2) A Section 1307 Surcharge and Tariff to Recover AEPS Costs, Prefiled Direct Testimony, March 19, 2007.

- **Masspower**
  Before the Superior Court Department of Suffolk County, Massachusetts, *Massachusetts Municipal Wholesale Electric Company v. Masspower, et al*., Civil No. 05-02710 (BLS1), on the changes in conditions in the electric industry in New England as they relate to Masspower's performance under its power supply agreement with

MMWEC; Expert Report, September 11, 2006; oral testimony under cross examination at trial, October 16-17, 2006.

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Proposed general increase in electric rates, general restructuring of rates, price unbundling of bundled service rates, and revision of other terms and conditions of service, Docket No. 05-0597, Rebuttal Testimony, January 30, 2006; Surrebuttal Testimony, March 14, ,2006; oral testimony under cross-examination, March 23, 2006. Testimony on rehearing, September 20, 2006.

- **Commonwealth Edison Company**
  Before the *Illinois House of Representatives, Electric Utility Oversight Committee*, on the Pay-as-Bid versus Uniform Price Auction Approach To Procurement of Wholesale Power for ComEd's Full-Requirements Customers, January 18, 2006, Springfield, Illinois.

- **Louisville Gas & Electric Company and Kentucky Utilities Company**
  Before the *Kentucky Public Service Commission*, Application of LG&E and KU to transfer functional control of their transmission assets, Case No. 2005-xxxx, Direct Testimony, November 19, 2005.

- **Western Massachusetts Electric Company**
  Before the Superior Court Department of Norfolk County, Massachusetts, *Alternative Power Source, Inc., v. Western Massachusetts Electric Company*, Civil Action No. 00-1967, on the allocation of costs related to transmission congestion in wholesale power contract for standard offer service. Expert Report, September 19, 2001; deposition, October 15, 2001; testimony at trial, July 15, 2005.

- **Entergy Louisiana, Inc. and Entergy Gulf States Inc.**
  Before the *Louisiana Public Service Commission*, Application of Entergy Louisiana, Inc. for Approval of the Purchase of Electric Generating Facilities and Entergy Gulf States, Inc. for Authority to Participate in Contract for the Purchase of Capacity and Electric Power, Docket No. U27836, January 21, 2005.

- **Louisville Gas & Electric Company and Kentucky Utilities Company**
  Before the *Kentucky Public Service Commission*, Investigation Into The Membership of Louisville Gas and Electric Company and Kentucky Utilities Company In The Midwest Independent Transmission System Operator, Inc., Case No. 2003-00266, September 29, 2004; Supplemental Rebuttal Testimony, January 10, 2005; testimony at hearing, June 2005.

- **Entergy Services Inc.**
  Before the *Federal Energy Regulatory Commission,* Entergy Services Inc., et al., in support of the application for approval of market-based power purchase agreements under Section 205 of the Federal Power Act. Affidavit, February 28, 2003; Affidavit, March 31, 2003; Testimony, September 2003; Testimony at deposition, November 20, 2003; Rebuttal Testimony, May 11, 2004; Deposition, May 27, 2004, and June 10-11, 2004; Testimony under cross-examination, July 19-23, 26-27, 2004.

- **Pacific Gas & Electric Company**
  Before the *California Public Utilities Commission*, In Re: Order Instituting Investigation into the ratemaking implications for Pacific Gas and Electric Company (PG&E) pursuant to the Commission's Alternative Plan of Reorganization under Chapter 11 of the Bankruptcy Code for PG&E, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Company, Investigation 02-04-026, Pre-Filed Testimony, July 23, 2003, Testimony under cross-examination, September 12, 2003.

- **Entergy Louisiana, Inc.**
  Before the *Louisiana Public Service Commission, Entergy Service*, In Re: Application of Entergy Louisiana, Inc., for Authorization to Enter into Certain Contracts for the Purchase of Capacity and Energy, Docket No. U-27136, Rebuttal Testimony, April 25, 2003.

- **Pacific Gas and Electric Company/PG&E Corporation**
  Before the *Federal United States Bankruptcy Court, Northern District of California, San Francisco Division*, In Re: Pacific Gas and Electric Company, Debtor, Federal I.D. No. 94-0742640, on the public policy concerns raised by the proposed reorganization plan of PG&E Corporation. Expert report, November 8, 2002; rebuttal report, November 26, 2002.

- **PP&L Global**
  Before the *New York Public Service Commission, Article X Siting Board*, on the economic and environmental

benefits of the Kings Park Energy power plant. Prefiled direct testimony (with James Potter, Stephen T. Marron, David J. Kettler, and Thomas Conoscenti), January 2002; rebuttal testimony (with James Potter, Stephen T. Marron, William C. Miller, Jr., N. Dennis Eryou, and Robert W. Brown), October 23, 2002.

- **Connecticut Light & Power Company**
  Before the *Federal United States District Court, District of Connecticut, Connecticut Light & Power Company v. NRG Power Marketing Inc.*, on their standard offer service wholesale sales agreement. Expert report, August 30, 2002; deposition, September 27, 2002.

- **Pacific Gas and Electric Company/PG&E Corporation**
  Before the *Federal Energy Regulatory Commission, in the Matter of Pacific Gas and Electric Company, PG&E Corporation, on behalf of its Subsidiaries Electric Generation LLC, ETrans LLC, and GTrans LLC,* on the public benefits of the application seeking approval under Section 203 of the Federal Power Act and Section 12 of the Natural Gas Act for various actions relating to restructuring of the company to emerge from bankruptcy, November 30, 2001.

- **Cross-Sound Cable Company LLC**
  Before the *Connecticut Siting Council*, on the public benefits of the proposed Cross Sound Cable Project's *Application for a Certificate of Environmental Compatibility and Public Need*, Docket No. 208. Prepared direct testimony, July 23, 2001; oral testimony under cross-examination, October 24-26, 29-30, 2001.

- **Sithe New England (Sithe Edgar LLC, Sithe New Boston LLC, Sithe Framingham LLC, Sithe West Medway LLC, Sithe Mystic LLC)**
  Before the *Federal Energy Regulatory Commission, in the Matter of NSTAR Electric & Gas Corp., v. Sithe Edgar LLC, Sithe New Boston LLC, Sithe Framingham LLC, Sithe West Medway LLC, Sithe Mystic LLC, and PG&E Energy Trading*, Docket No. EL01-79-000. Affidavit comparing historical cost recovery by Boston Edison for its fossil generation units (pre-divestiture) under rate regulation, versus Sithe's revenue recovery for these same units (post-divestiture) under market prices, June 5, 2001.

- **NRG Energy Inc. and Dynegy Holdings Inc.**
  Before the *Public Utilities Commission of Nevada*, In Re: petition of the Attorney General's Bureau of Consumer Protection to issue an Order staying further proceedings regarding divestiture of Nevada's electric generation assets and to open a docket to consider whether to issue a moratorium on divestiture in Nevada. Supplemental prepared direct testimony on behalf of Valmy Power LLC, April 6, 2001; testimony under cross-examination.

  Before the *Public Utilities Commission of Nevada*, In Re: petition of the Attorney General's Bureau of Consumer Protection to issue an Order staying further proceedings regarding divestiture of Nevada's electric generation assets and to open a docket to consider whether to issue a moratorium on divestiture in Nevada, prepared direct testimony on behalf of Reid Gardner Power LLC and Clark Power LLC, April 3, 2001; testimony under cross-examination.

- **Sithe New England, LLC**
  Before the *Federal Energy Regulatory Commission, In the Matter of Maine Public Utilities Commission and The United Illuminating Company v. ISO New England, Inc.*, affidavit on the role of price "spikes" in compensating generators for the services that they provide in the region, September 7, 2000.

- **Arkansas Electric Distribution Cooperatives**
  Before the *Arkansas Public Service Commission, In the Matter of a Generic Proceeding to Establish Uniform Policies and Guidelines for a Standard Service Package*. Prepared joint reply testimony (with Janet Gail Besser), July 21, 2000; prepared joint surreply testimony (with Janet Gail Besser), August 3, 2000.

- **TransEnergie U.S.**
  Before the *Connecticut Siting Council*, on the public benefits of the proposed Cross Sound Cable Project. Expert report, July, 2000; prepared direct testimony, September 20, 2000; oral testimony, September 27, 2000; supplemental written testimony, December 7, 2000; oral testimony under cross-examination, December 14, 2000; oral testimony January 9-11, 2001.

- **SCS Energy Corp.**
  Before the *New York State Public Service Commission*, on the economic and environmental impact of a new combined cycle power plant in Queens, NY, June 19, 2000.

- **Reading Municipal Light Department**

Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB 97-4*, on the economics and need for a new natural gas pipeline, June 19, 2000; testimony under cross-examination September 19, 2000, September 21-22, 2000, October 5, 2000, and October 17, 2000.

- **Fitchburg Gas and Electric Light Company**
  Before the *Massachusetts Department of Telecommunications and Energy, Docket D.T.E. 99-66*, on gas and electric company rate design policy, testimony under cross-examination, January 14, 2000.

- **FirstEnergy Corp.**
  Before the *Public Utilities Commission of Ohio*, In the Matter of the Application of FirstEnergy Corp. on behalf of Ohio Edison Company, the Toledo Edison Company, and The Cleveland Electric Illuminating Company: for Approval of an Electric Transition Plan and for Authorization to Recover Transition Revenues (Case No. 99-1212-EL-ETP); for Approval of New Tariffs (Case No. 99-1213-EL-ATA); for Certain Accounting Authority (Case No. 99-1214-EL-AAM), on recovery of transition costs and calculation of the market value of generation assets. Joint testimony (with Dr. Scott T. Jones), December 22, 1999; supplemental testimony (with Dr. Scott T. Jones), April 4, 2000; deposition, April 7, 2000.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-10*, in support of an application to construct a 540 MW gas-fired single cycle peaking power plant in Medway, Massachusetts. Prepared direct testimony, April 1999; oral testimony under cross-examination, July 27, 1999.

- **Village of Bergen, et al.**
  Before the *Supreme Court of the State of New York, Index No. 081556*, Affidavit in Response to Defendant's Submission of February 25, 1999, in *Village of Bergen, et al., Plaintiffs, v. Power Authority of the State of New York, Defendant*, March 3, 1999.

  Before the *Supreme Court of the State of New York*, *Index No. 081556*, Affidavit in Support of Petition to Correct Rates, in *Village of Bergen, et al., Plaintiffs, v. Power Authority of the State of New York, Defendant*, October 17, 1996.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-7*, in support of an application to construct a 750 MW gas-fired combined cycle power plant at the Fore River Station in Weymouth, Massachusetts (Edgar). Prepared direct testimony, February 10, 1999; oral testimony under cross-examination, July 26, 1999.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-8*, in support of an application to construct a 1500 MW gas-fired combined cycle power plant at the Mystic Station in Everett, Massachusetts. Prepared direct testimony, February 10, 1999; oral testimony under cross-examination, May 25, June 2, 1999.

- **U.S. Generating Company**
  Before the *Connecticut Siting Board, Docket No. 189*, on an application to construct a new Lake Road Generating Project, September 1998. Oral testimony under cross-examination.

- **Central Hudson Gas & Electric Corporation**
  Before the *Supreme Court of New York, Index No. 255/1998, CHGE v. West Delaware Hydro Associates*, on issues relating to ratemaking treatment of costs relating to power contracts, April 13, 1998.

- **Sithe New England Holdings, LLC**
  Before the *Massachusetts Department of Telecommunications and Energy and the Massachusetts Energy Facilities Siting Board, Docket Nos. DTE98-84 and EFSB98-5,* on issues pertinent to forecast and supply planning by electric companies, September 14, 1998.

- **Sithe Energies, Inc.**
  Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB98-3,* on issues related to the agency's rulemaking establishing a Technology Performance Standard, June 8, 1998.

  Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB98-1,* on issues related to the agency's review of project viability as part of review of power plant applications, March 16, 1998.

- **Pennsylvania Power & Light**
  Rebuttal testimony on codes of conduct governing affiliate relations. *Pennsylvania Public Utility Commission*,

Docket Nos. A-122050F0003, A-120650F0006, testimony under cross-examination, February 17, 1998.

Rebuttal testimony on rate unbundling and rate design issues, on consumer protection issues. *Pennsylvania Public Utility Commission, Docket No. R-00973954,* testimony under cross-examination, August 5, 1997.

Before the *Penn Public Utility Commission, Docket No. R-00973954*, on rate design, April 1, 1997.

- **Nextel Communications**
  Before the *Massachusetts Department of Public Utilities, Docket 95-59-B,* on telecommunications facility matters, testimony under cross-examination, January 1997.
- **Arizona Public Service Company**
  Before the *Arizona Corporation Commission, Docket No. U-0000-95-506,* on integrated resource planning and competition, October 1996.
- **U.S. Generating Company**
  Before the *Massachusetts Energy Facilities Siting Board, Docket 96-4,* on an application to construct a new Millennium power generating facility, testimony under cross-examination, October 1996.
- **MCI Communications, Inc.**
  Before the *Massachusetts Department of Public Utilities*, in the NYNEX interconnection docket. Opening up the Local Exchange Market to Competition: Common Themes with Retail Competition in Electricity and Natural Gas Industries, August 30, 1996.
- **Intercontinental Energy Corporation**
  Before the *New Jersey Board of Public Utilities, No. EX94120585Y,* on the Energy Master Plan Phase I Proceeding to Investigate the Future Structure of the Electric Power Industry, July 1996.

  Before the *Massachusetts Department of Public Utilities, DPU 96-100,* on the Investigation Commencing a Notice of Inquiry/Rulemaking for Electric Industry Restructuring, July 1996.

PUBLICATIONS, REPORTS, ARTICLES

Tierney, Susan, **"**Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 8, 2014.

Tierney, Susan, "State shouldn't pursue hydropower from Quebec," *The Boston Globe* Opinion (The Podium (online)), March 25, 2014.

Hibbard, Paul, Susan Tierney, and Pavel Darling, "The Impacts of the Green Communities Act on the Massachusetts Economy: A Review of the First Six Years of the Act's Implementation," March 4, 2014.

Arvizu, Dan, Severin Borenstein, Susan Tierney, and Stephen Wright, "Report of the Independent Advisory Panel Regarding the Five California Utilities' Study of Integration of Renewable Energy into California's Electric System: 'Investigating a Higher Renewables Portfolio Standard in California'," January 2014.

Tierney, Susan, with Steve Carpenter, "Planning for Offshore Energy Development: How Marine Spatial Planning Could Improve the Leasing/Permitting Processes for Offshore Wind and Offshore Oil/Natural Gas Development," paper prepared for the Fund for Ocean Economic Research," June 2013.

Tierney, Susan, "Framing the Issues: Growing Tensions at the Interface of the Natural Gas and Electricity Markets (or, If You Want People to Think Outside of the Box, Don't Put Them in One)," paper prepared for MIT Energy Initiative (MITEI) Symposium: Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems, April 16, 2013.

Hibbard, Paul, Andrea Okie, Susan Tierney, "California's Advanced Energy Economy: Advanced Energy Business Leaders' Perspectives and Recommendations on California's Energy Policies," February 2012.

Alliance Commission on National Energy Efficiency Policy (Susan Tierney, member), "Energy 2030: Doubling U.S. Energy Productivity by 2030," February 2013.

Bipartisan Policy Center Energy Project (Susan Tierney, member), "America's Energy Resurgence: Sustaining Success, Confronting Challenges," February 2013.

Tierney, Susan, Co-lead Convening Author, Energy Supply and Use Chapter, Draft National Climate Assessment, January 2013.

Tierney, Susan, "The Positive Outlook for Cleaner Air and Reliable Electric Service," June 11, 2012.

Tierney, Susan, "America's Bright Future: Cleaner Air and Affordable, Reliable Electricity," April 23, 2012.

Tierney, Susan, Foreword to CERES Report, "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know (How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection," authored by Ron Binz, with Richard Sedano, Denise Furey, Dan Mullen, April 2012.

Tierney, Susan, "Time to retire coal-fired plants," Politico, March 20, 2012.

Tierney, Susan, "Why Coal Plants Retire: Power Market Fundamentals as of 2012," February 16, 2012.

Hibbard, Paul J., and Susan F. Tierney, "Carbon Control and the Economy: Economic Impacts of RGGI's First Three Years." *Electricity Journal*, December 2011.

Deutch, John, Steven Holditch, Fred Krupp, Kathleen McGinty, Mark Zoback, Susan Tierney, and Daniel Yergin, "The Secretary of Energy Advisory Board Shale Gas Production Subcommittee Second Ninety-Day Report" (on steps to address the environmental and safety performance of shale gas extraction) November 18, 2011.

Hibbard, Paul J., Susan F. Tierney, Andrea M. Okie, Pavel G. Darling, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States: *Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period,* November 15, 2011.

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Hibbard, Paul J., Pavel Darling, and Susan Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," prepared for the American Clean Skies Foundation, July 19, 2011.

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"Electric Power Systems: The Outlook for Electric Transmission: Where You Stand Depends Upon Where You Sit," Harvard Law School, March 20, 2014.

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"The World of Abundant Natural Gas in the U.S.: Looking Ahead for Power-Sector Implications," presentation to the Keystone Energy Board, Washington, DC, October 30, 2013.

"Energy: From the Last to the Next 150 years," keynote address to the Energy Forum of Boston College's Sesquicentennial Celebration, October 25, 2013.

"Capacity Markets in the Northeast: A Preview of Comments at the FERC Technical Conference on Centralized Capacity Markets in RTOs/ISOs," presentation to the Independent Power Producers of New York, Saratoga Springs, New York, September 10, 2013.

"Opportunities and Risks of Shale Gas Development," presentation to the Governors' Policy Forum on Shale Energy Development, National Governors Association, Denver, September 9, 2013.

"The National Climate Assessment (Draft): Chapter on Energy Supply and Use," presentation to the National Association of Regulatory Utility Commissioners, Denver, July 23, 2013.

"Climate Change Preparedness in New Jersey: Utilities – Leading Practices and Trends Nationally," presentation to the New Jersey Climate Adaptation Alliance, Rutgers University, New Brunswick, May 21, 2013.

"Is New England Over-Reliant on Natural Gas?" presentation to the 20th Annual Energy Conference of the Northeast Energy and Commerce Association, Groton CT, May 21, 2013.

"Jevons' Boomerang: Is the rebound effect real? If so, is the effect negative or positive?" presentation to the EE Global Conference, Washington, DC, May 20, 2013.

"Framing the Issues: Growing Tensions at the Interface of the Natural Gas and Electric Industries," presentation to the MIT Energy Initiative (MITEI) Symposium on "Growing Concerns, Possible Solutions: Gas/Electric Interdependence," April 16, 2013.

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"Global Energy Security: Upcoming challenges and opportunities (from a U.S. vantage point)," Tufts University Energy Conference – Powering Global Energy Security, Medford, Massachusetts, March 3, 2013.

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“The Future of Energy,” DOE Energy All Stars, Department of Energy, January 19, 2013.

“The Economic Impacts of RGGI’s First Three Years,” Columbia University Law School – Center for Climate Change Law, Conference on the Future of the Regional Greenhouse Gas Initiative, New York, City, October 22, 2012.

“Reality Check on Energy Conditions,” New Hampshire Energy Summit, Concord, NH, October 22, 2012.

“Natural gas and renewables: Curious bedfellows,” Renewable Energy Law & Policy Summit, University of Denver Sturm College of Law, October 19, 2012.

“Smart Grid and Air Emissions,” Gridweek, Washington DC, October 4, 2012.

“C3E Women in Clean Energy Symposium,” Keynote Address, Boston, September 28, 2012.

“Natural Gas: Risks and Opportunities – Shale Gas, Hydraulic Fracturing, and Other Facts,” EPA Region 1 seminar, Boston, September 27, 2012.

“Finding the Sensible Middle: Policies and Institutional Roles in Unconventional Gas Development,” Unconventional Gas Research Forum, Board on Energy and Environmental Systems, National Academy of Sciences, Washington DC, September 11, 2012.

“Unlocking the Potential of Regional Collaboration,” California ISO Stakeholders Symposium, Sacramento, September 6, 2012.

“The Context for Compliance with EPA Air Regulations: Power Market Conditions,” EPA/DOE/NETL/ EPRI/AWMA Power Plant Air Pollution Control Mega-Symposium, Baltimore, August 20, 2012.

“Finding the Sensible Middle: Unconventional Gas Development,” 24th Annual Natural Gas Strategy Conference & Executive Forum, August 15, 2012.

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“China’s Energy Challenges and Policy Responses: Observations from a U.S. Vantage Point,” Connecticut College Vietnam Program, June 15, 2012.

“Economic Impacts of RGGI: Following the Dollars,” presentation to the RGGI Board, June 2012.

“The Energy Scene: Update on a Few Key Issues,” presentation to the Ozone Transport Commission, April 23, 2012.

“Shale Gas: Analyzing Risks and Opportunities,” Society for Risk Assessment, Boston University – April 9, 2012

“Sustainable Energy Highway,” New York State Energy Highway Summit, April 4, 2012.

“Electric and Natural Gas Markets – Interactions, Opportunities, Challenges (with a focus on Texas), Gulf Coast Power Association Spring Meeting, April 3, 2012.

“Natural Gas: Risks and Opportunities – Shale Gas, Hydraulic Fracturing, and Other Facts,” Tufts University – Fletcher School, March 29, 2012.

"Fracking and Shale Gas, Part I: Impacts on Energy Markets and Massachusetts," Boston Bar Association, March 6, 2012.

"Electric Power Systems: "The Outlook for Electric Transmission: Where You Stand Depends Upon Where You Sit," Harvard Law School, February 16, 2012.

"Natural Gas: Policy Recommendations of the NPC, SEAB, and BPC," Energy, Utility and Environment Conference 2012, January 30, 2012.

"Economic Impacts of RGGI: Following the Dollars," Energy, Utility and Environment Conference 2012, January 30, 2012.

"Electric Power Systems: "The Outlook for Electric Transmission: Where You Stand Depends Upon Where You Sit," Yale University School of Forestry and Environmental Studies, January 24, 2012.

"U.S. Renewable Energy Policy: Overview, with comparisons to European approaches," presentation to the Wharton School, January 3, 2012.

"The Truth about Fracking," presentation to the New York Energy Forum, December 19, 2011.

"The Clean Energy Economy," presentation to the Environmental Lawyers, Environmental League of Massachusetts," November 30, 2011.

"Outlook for the Electric Generating Fleet: Effects of the Upcoming EPA Regulations," presentation to the Harvard Kennedy School Energy Policy Series, November 28, 2011.

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"Natural Gas: Risks and Opportunities (* with an emphasis on shale gas developments)," Harvard University Center for the Environment – Future of Energy Series, Cambridge, October 26, 2011.

"An Expanded Toolkit – Environmental Regulations, Natural Gas, and Modernizing the U.S. Generating Fleet," Great Lakes Symposium on Smart Grid and the New Energy Economy, Chicago, October 19, 2011.

"Pricing in a Western Energy Imbalance Market: Market Clearing Price versus Pay-As-Bid Pricing." Western Interstate Energy Board – Webinar on the Energy Imbalance Market," October 18, 2011.

"Federal and State Legislative and Regulatory Outlook: Connecting the Dots: Options for Upcoming Electric Resources," Emerging Issues Policy Forum, Amelia Island, October 9, 2011.

"Environmental Challenges Associated with Meeting Future Energy Needs: The role of shale gas?" National Association of Clean Air Agencies, Cleveland, October 4, 2011.

"Facing tough realities: Upcoming Energy and Environmental Issues – With a Focus on Electricity and Natural Gas," National Association of Clean Air Agencies, Cleveland, October 4, 2011.

"Assessing Natural Gas' New Promises and Controversies: Strategies to Improve the Safety & Environmental Performance of Shale Gas Extraction," Wisconsin Public Utilities Institute, University of Wisconsin at Madison, October 3, 2011.

"The Outlook for Natural Gas: Role of Shale Gas," EnerNOC EnergySMART Conference, Boston, September 27, 2011.

"The Outlook for Natural Gas: What does shale gas look like?" NECA Fuels Conference, Marlboro, MA, September 27, 2011.

"Facing tough realities: Upcoming Energy and Environmental Issues – With a Focus on Electricity and Natural Gas," Environmental Council of the States, Indianapolis, September 25, 2011.

"Electric Reliability Under EPA's New Air Regulations: What We Know, and What We Can Do About What We Don't Yet Know," National Association of State Energy Offices, September 12, 2011.

"The Future of Electricity Generation in the U.S. – A Modest Set of Observations," 19th Annual MIT-NESCAUM Endicott House Symposium (Opportunities for Technology and Policy Innovation in Energy and Environment), August

18, 2011.

"Unconventional Approaches: Part of the Electric Industry's Response to Upcoming EPA Regulations," Panel on Infrastructure Reliability and Adequacy at the Aspen Energy Policy Forum ("Changing Currents – Turbulence for the Electric Industry: Is Reliability a Real Issue for power plants given the EPA rules?), Aspen, July 5, 2011.

"What we know, what we might know, and what we know we don't know yet," Joint Meeting of the NARUC, NASEO, and NACAA states, Baltimore, June 23, 2011.

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"China's Energy Challenges and Policy Responses: Observations from a U.S. Vantage Point," Connecticut College Vietnam Program, June 16, 2011.

"Strategies for Addressing Change at FERC and the RTOs: A new lens on responding to near-term changes," FERC/RTO Training Session, Panel on "Beyond Reliability: Economics, driving efficiency, demand response, and clean energy," Sponsored by the Institute Policy Integrity, New York City, July 15th, 2011.

"'May you live in interesting times…': The Regulators' Tool-Kit in an Era of Uncertainty," Western Conference of Public Service Commissioner, Denver, June 14, 2011.

"Dirty to Clean? The future of Electric Power in America," CERES Conference 2011, Oakland, CA, May 12, 2011.

"EPA Regulations, Power Generation Capacity & Reliability," presentation to the MIT Center for Energy & Environmental Policy Research Workshop, Cambridge, MA, May 5, 2011.

"The Electric Industry's Response to EPA's Upcoming Regulations: Options for Owners and Others," presentation to the Energy Bar Association, Panel on Environmental Regulations, Washington, D.C., May 4, 2011.

"Framing the Issues: Energy and the Environment," Keynote address to the Health Effects Institute, Boston, May 2, 2011.

"Federal Air Pollution Regulations Affecting Fossil Power Plants: Current issues, implications, strategies," presentation to the 6th Annual Conference on Tribal Energy in the Southwest: New Opportunities for tribal projects, new policies, regulations and markets, Law Seminars International, Phoenix, April 29, 2011.

"China and U.S. Energy and Environmental Policy Challenges: Learning from Each Other, In It Together," presentation to China Energy & Environment Conference, Harvard University, April 9, 2011.

"EPA's MACT, Water Cooling Intake and Transport Rules: What now for power generation?" presentation to SNL Energy Webinar, April 12, 2011.

"Policies for a Secure Energy Future: Issues in Supply and Demand," presentation to the Aspen Institute Congressional Program's meeting on Energy Security: Policy Considerations in the New Congress, San Juan, Puerto Rico, February 22-27, 2011.

"Responding to EPA's Regulations Affecting Coal Plants: Using a 21st Century Toolkit (or, upgrading to the "Champ" from the "Classic"), presentation to the Panel on Environmental Regulations and Impacts on Electricity System Infrastructure, 2011 DOE/NARUC National Electricity Forum, Washington, D.C., February 16, 2011.

"Responding to EPA's Regulations Affecting Coal Plants: Using a 21st Century Toolkit (or, upgrading to the "Champ" from the "Classic"), presentation to the Roundtable on the EPA Regulations, NARUC Winter Meeting, Washington, D.C., February 14, 2011.

"Local, State and Regional Coordination and Solutions: Non-conventional capacity and energy resources," presentation to the Bipartisan Policy Center's Workshop on Power Sector Environmental Regulations, Washington, D.C., January 19, 2011.

"Renewable Energy in New England," presentation to the New Hampshire Business and Industry Conference, Concord, New Hampshire, December 7, 2010.

"Framing the Issues: Energy and the Environment," presentation to the annual meeting of the National Academy of Public Administration, Washington, D.C., November 18, 2010.

"Toolkit for Ensuring Reliable, Economic Responses to EPA's Proposed Air Regulations," presentation on the panel on "The Climate Syndrome: Without Congressional Action, What Do State Regulators Need to Know?" NARUC Meeting, Atlanta, Georgia, November 17, 2010.

"Challenges for Recovering Costs During a Push for Cleaner Generation and More Efficient Energy Use," Law Seminars International conference (Utility Rate Cases), Boston, November 9, 2010 (conference co-chair).

"Public Policy for Advanced Energy Technology," presentation to the New York Advanced Energy Technology Conference, New York City, November 8, 2010.

"Energy Future: Bridging the Gap," presentation to the Wharton Energy meeting, Philadelphia, October 28, 2010.

"Upcoming Power Sector Environmental Regulations: Framing the issues about potential reliability/ cost impacts," presentation to the National Commission on Energy Policy Workshop on Power Sector Environmental Regulations, Washington, D.C., October 22, 2010.

"Vulnerability of the Gulf Coast Energy Infrastructure," presentation to the Deltas 2010 – World Deltas Dialogue, America's Energy Coast Policy Forum on The Future of the U.S. Gulf Coast Energy Infrastructure in the Face of Changing Climate," New Orleans, October 20, 2010.

"Today's Energy Landscape: Scanning the terrain – with tips for a safe journey," presentation to the annual meeting of the National Association of State Energy Officials, September 30, 2010.

"2020: What can we expect? Where we are now, and how it influences where we'll be a decade from now," Law Seminars International conference, "Energy in the Northeast," September 29, 2010.

"Today's Energy Landscape: Exploring economic, environmental and technological trends," presentation to the annual meeting of the Independent Power Producers of New York, September 22, 2010.

"Transforming America's Energy Systems: Challenges and opportunities along the nation's coastal and marine environments," Annual Lecture at the Metcalf Institute, University of Rhode Island, June 8, 2010.

"New England at the Crossroads: The Intersection between Regulatory Policy and Future Energy Supply," presentation to the Northeast Energy and Commerce Association, 17th New England Energy Conference, Green Thumb on the Scale: Impact on Future Energy Choices, June 8, 2010.

"Is Competition Dead?" presentation to the Annual Meeting of the New England Conference of Public Utility Commissioners, May 17, 2010.

"Why it is so Darn Hard to Adopt Advanced Energy Technologies, But So Worth the Effort," presentation to the Tufts University Energy Conference, "The Evolution of Energy," April 17, 2010.

"The Prospects for Natural Gas, Coal, and Nuclear Power in America's Energy Future," discussions with members of Congress at the Aspen Institute's Congressional Program on Energy Security and Climate Change: Policy Challenges for the Congress, April 6-10, 2010.

"Why is Modernizing Our Energy Technologies So Darn Hard, But Worth the Effort?" presentation to the MIT Energy Initiative Lecture Series, February 2, 2010.

"Themes in federal energy and climate policy issues in Washington – end of 3rd Q, 2009," presentation to the Kennedy School, Harvard University, November 18, 2009.

"Update on federal energy and climate policy issues in Washington – end of 3rd Q, 2009," presentation to the New York Independent System Operator Environmental Advisory Council, October 23, 2009.

"Challenges and Opportunities in Colorado's New Energy Economy – A View From Washington," presentation to the "Powering the Future – Colorado's New Energy Economy," Denver, Colorado –October 20th, 2009.

Financial Meltdown and Recovery: Challenges and Opportunities in the New Clean Energy Economy – Taking Stock in 3rd Q 2009," ABA Environment, Energy and Resources Law Summit 17th Section Meeting – Baltimore, September 25, 2009.

"Off-Shore Renewable Energy Development in NE: Massachusetts's New Ocean Management Plan," presentation to the New England Electric Restructuring Roundtable, September 18, 2009.

"Energy Policy for the 'Climate Change Era' – What's Your Definition of Green?" presentation to the 55th Annual Rocky Mountain Mineral Law Institute, San Francisco, July 23, 2009.

"The Goals for an Electricity Grid for the 21st Century: Where You Stand Depends Upon Where You Sit," presentation to the Aspen Institute Energy Policy Forum, Aspen, Colorado, July 9, 2009

"Linking Ends and Means in Energy & Environmental Policy: Intended and Unintended Consequences," presentation to the Harvard Electricity Policy Group, Cambridge, Massachusetts, May 28, 2009.

"Today's Energy Landscape: What's Coming Next for Energy & Resources Policy & Regulations," presentation to the Chief EH&S Officers Council (Joint with EH&S Legal Officers), The Conference Board – Washington, DC, May 14, 2009.

"Scanning Today's Energy Landscape in New England: Objects are Closer Than They Appear," Presentation to the New England Conference of Public Utility Commissioners, Newport, Rhode Island, May 3, 2009.

"Today's Energy Landscape: Objects are Closer Than They Appear." Presentation to the Energy Bar Association's 63rd Annual Meeting: Infrastructure, Policy, and Practice Amidst Economic Turmoil, Washington, D.C., April 23, 2009.

"Regulatory Treatment of Purchased Power: Pass Through or Profit Center? Give Away or Value Creation?" presentation to Harvard Electricity Policy Group, October 3, 2008., Harvard Electric Policy Group – Chicago, Illinois, October 3, 2008.

"Leadership Panel: Barriers to Acting in Time on Energy, and Strategies for Overcoming Them," Harvard University Conference: Acting in Time on Energy Policy, September 18, 2008.

"New England's Power Markets: The context for renewables development," Law Seminars International, September 8, 2008.

OTHER PROFESSIONAL ACTIVITIES

Chair, ClimateWorks Foundation (2013-present)

Participant in studies of the Colorado State University's Center for Clean Energy Economy ("*Powering Forward: Presidential and Executive Agency Actions to Drive Clean Energy in America*," January 2014.

Co-Lead Convening Author, Energy Supply and Use Chapter, National Climate Assessment (2012-present)

Member, Committee on Risk Management and Government Issues in Shale Gas Development, of the National Academy of Sciences, Board on Environmental Change and Society (of the Division of Behavioral and Social Sciences and Education) (2013-2014)

Co-chair, Bipartisan Policy Center's Cyber-security and the Electric Grid project (2013-2014)

Co-chair, National American Energy Standards Board (NAESB) Gas-Electric Harmonization Committee (2012, 2014)

Alliance Commission on National Energy Efficiency Policy (2012-2013): Report (Energy 2030: Doubling Energy Productivity by 2030; February 2013).

Bipartisan Policy Center – Energy Project (2011 to present): Report ("America's Energy Resurgence: Sustaining Success, Confronting Challenges," February 2013).

U.S. Secretary of Energy Advisory Board (July 2010 to May 2013). Member of the Natural Gas Subcommittee examining shale gas development. (2011-2013)

Chair, Policy Subgroup of the National Petroleum Council's study on North American Gas and Oil Resource Development (2010-2011)

Member, Board of Directors, Alliance to Save Energy (2011 to present)

Visiting Professor, Department of Urban Studies and Planning, Massachusetts Institute of Technology, Spring 2010.

Massachusetts Clean Energy Grand Prize Judge, May 11, 2010.

Member, Board of Directors, EnerNOC, Inc. (February 2010 to May 2013)

Member, Board of Directors, World Resources Institute (2009 to present). Chair of Presidential Search Committee (2011).

Co-Lead, Department of Energy Agency Review Team, Obama/Biden Presidential Transition Team, Washington D.C., 2008-2009 (while on full-time leave for four months from Analysis Group).

Chair, Massachusetts Ocean Advisory Commission, 2008 to 2010.

Member, Board of Directors, Evergreen Solar, Inc., 2008 to 2011.

Member, Board of Directors, Ze-gen Inc., 2009 to 2011, Market Advisory Board, 2008-2009.

Member, Board of Directors, Renegy Holdings, 2007 to 2009.

Member, Blue Ribbon Commission on Cost-Allocation Issues for Transmission Investment, WIRES, 2007.

Chair, External Advisory Council, National Renewables Energy Laboratory (2009 to present).

Member, National Academy of Sciences Committee on Enhancing the Robustness and Resilience of Electrical Transmission and Distribution in the United States to Terrorist Attack, 2005 to 2008.

Member, New York Independent System Operator, Environmental Advisory Council, 2004 to present.

Member, National Commission on Energy Policy, member, 2002 to 2011; co-chair, 2009-2011.

Member, Board of Directors, Clean Air Task Force, 2008-June 3, 2013; Advisory Council, 2002 to 2008.

Member, Board of Directors, Catalytica Energy Systems Inc., 2001 to 2007.

Member, Board of Directors, Climate Policy Center, 2001 to 2007.

Member, Advisory Committee, Carnegie Mellon Electricity Industry Center, 2001 to 2009.

Member, Policy Advisory Committee, China Sustainable Energy Project–A Joint Project of The Packard Foundation and The Energy Foundation (1999 to present).

Director, NorthEast States Center for a Clean Air Future, 1998 to 2010.

Chair of the Board of Directors, The Energy Foundation, 2000 to 2011; Vice-Chair, 1999-2000; Director, 1997 to 2011; Director, 2013 to present.

Chair of the Board of Directors, Clean Air–Cool Planet / Climate Policy Center, 2004 to 2009; director, 1999-present.

Member, Board of Directors, ACORE (American Council on Renewable Energy), 2006-2007.

Co-Chair, Energy/Environment Working Group, Governor Deval Patrick Transition Team (2006-2007).

Presenter, Economic Issues, National LNG Forums, U.S. Department of Energy, Boston Massachusetts; Astoria, Oregon (2006).

Chair of the Technical Review Panel, Critical Infrastructure Protection Decision Support Systems (CIP-DSS), Argonne, Los Alamos and Sandia National Laboratories, 2006.

Advisory Council member, New England Energy Alliance, 2005-2006.

Member, Board of Directors, Electric Power Research Institute, 1998 to 2003, 2005-2006.

Chair of the Laboratory Direction's Division Review Panel for the Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, 2005.

Chair, Ocean Management Task Force, Commonwealth of Massachusetts, 2003-2004.

Co-Chair, RTO Futures: Regional Power Working Group, 2001-2002.

Chair, Board of Directors, Electricity Innovations Institute, 2002 to 2004; Director, 2001 to 2002.

Member, Florida Energy 2020 Study Commission, Environmental Technical Advisory Committee, 2001.

Technical Advisor, Mid-Atlantic Area Council/PJM, Dispute Resolution Procedure, 1998 to 2008.

Member, "ISO-New England" (Independent System Operator) Advisory Committee, 1998 to 2003.

Director, The Randers Group (subsidiary of Thermo TERRATEK), 1997 to 2000.

Director, MHI, Inc. (electric utility aggregator in Massachusetts), 1997 – 1999.

Director, Thermo ECOTEK Corporation, 1996 – 1999.

Member, United States Department of Energy, Electricity Reliability Task Force, 1996-1998.

Member, Harvard Electricity Policy Group, 1993 to 2005.

HONORS AND AWARDS

Champions Award, Charles River Watershed Association, 2013

Leadership Award, New England Women in Energy and the Environment, 2013.

Clean Energy Hall of Fame, New England Clean Energy Council, 2012.

DOE Women in Clean Energy Initiative, C3 Ambassador, 2012

Climate Champion Award, Clean Air – Cool Planet, 2009.

Distinguished Alumna Award, Scripps College, Claremont, CA, 1998

Award for Individual Leadership in Public Service, *The Energy Daily*, 1995

Special Recognition Award for Outstanding Contribution to the Industry, Cogeneration and Competitive Power Institute, Association of Energy Engineers, 1994

Leadership Award, National Association of State Energy Officials, 1994

Commencement Speaker and Honorary Doctorate of Laws, Regis College, Weston, MA, 1992.

S.F. Tierney Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants _________(G)-2

JOINT APPLICANTS (G)-2
Examples of the District of Columbia Agency Studies that Use IMPLAN

In preparation for this testimony, I searched the internet to find instances where a District of Columbia government agency had used or contracted for, or had submitted before it, a study that used IMPLAN for an economic impacts analysis. A few of the examples include:

- Report prepared by Mayor's Power Line Undergrounding Task Force pursuant to EO 2012-130, "Findings and Recommendations" (May 2013), available at: http://oca.dc.gov/sites/default/files/dc/sites/oca/page_content/attachments/Mayor%27s%20Power%20Line%20Undergrounding%20Task%20Force%20-%20Findings%20and%20Recommendations%20Report%20%28Abridged%20Version%29-May%202013.pdf.
- Report prepared for Metropolitan Washington Airports Authority by the Louis Berger Group, Inc., "Technical Report: Economic Impact Study - 2009" (October 2010), available at: http://www.mwaa.com/file/mwaa_-_economic_impact_study_2009_-_02_tech_report_final_10_20_2010.pdf.
- Report prepared for the DC Office of Motion Picture and Television Development by ECONorthwest, "An Analysis of the Entertainment and Media Industry in Washington, D.C." (July 2013), available at: http://www.dcfpi.org/wp-content/uploads/2013/09/ECONorthwest-Study.pdf.
- Report commissioned by DC Office of Local Business Development, "Evaluation: Local Small Disadvantage Business Enterprise Program: Cost Effectiveness and Financial Impact Analysis" (December 2002), available at: http://www.dcps.dc.gov/DC/DSLBD/DSLBD%20Publication%20Files/Evaluation%20LSDBE%20Enterprise%20Program.pdf.

S.F. Tierney Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants ________ (G)-3

JOINT APPLICANTS (G)-3
Description and Overview of IMPLAN and Definition of Terms[27]

IMPLAN's Social Accounting Matrices ("SAMs") capture the actual dollar amounts of all business transactions taking place in a regional economy as reported each year by businesses and governmental agencies. SAM accounts are a better measure of economic flow than traditional input-output accounts because they include "non-market" transactions. Examples of these transactions would be taxes and unemployment benefits.

SAMs can be constructed to show the effects of a given change on the economy of interest. These are called Multiplier Models. Multiplier Models study the impacts of a user-specified change in the chosen economy for 440 different industries. Because the Multiplier Models are built directly from the region specific SAMs, they will reflect the region's unique structure and trade situation. Multiplier Models are the framework for building impact analysis questions. Derived mathematically, these models estimate the magnitude and distribution of economic impacts, and measure three types of effects which are displayed in the final report. These are the direct, indirect, and induced changes within the economy.

Direct effects are determined by the Event as defined by the user (i.e. a $10 million dollar order is a $10 million dollar direct effect). The indirect effects are determined by the amount of the direct effect spent within the study region on supplies, services, labor and taxes. Finally the induced effect measures the money that is re-spent in the study area as a result of spending from the indirect effect. Each of these steps recognizes an important leakage from the economic study region spent on purchases outside of the defined area. Eventually these leakages will stop the cycle. More specifically, the effects are:

> *Direct effects* - The set of expenditures applied to the predictive model (i.e., I/O multipliers) for impact analysis. It is a series (or single) of production changes or expenditures made by producers/consumers as a result of an activity or policy. These initial changes are determined to be a result of this activity or policy. Applying these initial changes to the multipliers in an IMPLAN model will then display how the region will respond, economically, to these initial changes.
>
> *Indirect effects* - The impact of local industries buying goods and services from other local industries. The cycle of spending works its way backward through the supply chain until all money leaks from the local economy, either through imports or by payments to value added. The impacts are calculated by applying Direct Effects to the Type I Multipliers.
>
> *Induced effects* - The response by an economy to an initial change (direct effect) that occurs through re-spending of income received by a component of value added. IMPLAN's default multiplier recognizes that labor income (employee compensation and proprietor income components of value added) is not a leakage to the regional economy. This money is recirculated through the household spending patterns causing further local economic activity.

[27] Information taken directly from IMPLAN.s website, available at http://implan.com/V4/Index.php.

S.F. Tierney Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants ________ (G)-4

JOINT APPLICANTS (G)-4
Overview of Core Inputs and Assumptions Used in
IMPLAN Analysis of Economic Benefits of the Regulatory Commitments to the District of Columbia

Activity	Actual Commitment and Modeled Use	Input Assumption in IMPLAN Study
Customer Investment Fund: Assuming a $52.95 credit on Each Customer's Utility Bill	$14 million, modeled as a $52.95 credit to each distribution customer	Residential benefits: Modeled as increased income to households Commercial/industrial benefits: Modeled as increased sales to businesses
Customer Investment Fund: Assuming the Funds are Spent on Energy Efficiency Measures	$14 million, modeled based on current District energy efficiency spending	Modeled in two parts: Part 1: Spending on appliance programs (retail sales) and residential and commercial/industrial retrofits/new construction programs (construction and maintenance) – ten year lifespan assumed Part 2: Customer electricity savings resulting from reduced usage modeled as increased income to residential customers, increased sales to commercial and industrial customers – ten year lifespan assumed
Customer Investment Fund: Assuming a Credit on Low-Income Residential Customers' Utility Bills	$14 million, modeled as a credit to low-income residential customers	Modeled as increased income to lowest residential income bracket
Reliability Benefits	Reliability benefits determined using Department of Energy ICE Calculator, commitments based on testimony of Mark Alden	Residential benefits: Modeled as increased income to households Commercial/industrial benefits: Modeled as increased sales to businesses

S.F. Tierney Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants ________ (G)-5

JOINT APPLICANTS (G)-5
Economic Impacts of the Customer Investment Fund and the Enhanced Reliability Commitments to Customers of Pepco and the District of Columbia

Direct Benefits to Customers of PEPCO	
Customer Investment Fund (2014)	$14,000,000
Value of Reliability Benefits to Customers (2015-2020) (NPV, 2014 $)	$75,868,218

Macroeconomic Benefits of the Merger to the District of Columbia						
	Customer Investment Fund					
	Assuming a $52.95 per Customer Credit on Each Customer's Utility Bill	Assuming the Funds are Spent on Energy Efficiency Measures	Assuming a Credit on Low-Income Residential Customers' Utility Bill	Enhanced Reliability Commitments	Total Economic Benefits (Low estimate)	Total Economic Benefits (Higher Estimate)
Jobs	62	436	73	846	907	1,281
Value Added (NPV, 2014$)	$19,090,341	$57,260,245	$22,153,091	$76,302,465	$95,392,806	$133,562,710
Incremental Tax Revenues (NPV, 2014$)	$459,701	$2,358,592	$640,345	$3,173,393	$3,633,095	$5,531,985

C.G. Butler Direct Testimony
DC P.S.C. - - June 18, 2014

Introduced as:
Joint Applicants __________ (H)

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JOINT APPLICANTS
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF CALVIN G. BUTLER, JR.
FORMAL CASE NO. _____

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your name and business address.

A. My name is Calvin G. Butler, Jr. My business address is 110 West Fayette Street, Baltimore, Maryland 21201.

2. Q. By whom are you employed and in what capacity?

A. I am the Chief Executive Officer ("CEO") of Baltimore Gas and Electric Company ("BGE" or the "Company").

3. Q. What is your professional and educational background?

A. I began my career at Central Illinois Light Company, where I worked in a variety of positions in the government affairs, legal, and operations areas before moving to R.R. Donnelley & Sons, Co. ("RR Donnelley"), a global producer of integrated communications. I spent eight years at RR Donnelley, first as senior director of government affairs and eventually as senior vice president of external affairs. I also managed the firm's supplier diversity and government sales groups and served as president of the R.R. Donnelley Foundation. I joined Commonwealth Edison Company ("ComEd") in 2008 as its Vice President of Legislative Affairs, where I managed all state and local legislative initiatives while overseeing real estate and facilities and economic development functions. In 2009, I was promoted to Senior Vice President of Corporate Affairs for ComEd.

On August 16, 2010, I accepted a position with Exelon Corporation ("Exelon") as its Senior Vice President of Human Resources and, on May 2, 2011, I became Senior Vice President of Corporate Affairs at Exelon. Following Exelon's 2012 acquisition of Constellation Energy Group ("Constellation") and its operating subsidiaries, I was named Senior Vice President, Regulatory and External Affairs at BGE. On March 1, 2014, I was named CEO of BGE. I also serve on BGE's Board of Directors and the Management Executive Committee of Exelon.

I received my bachelor's degree from Bradley University in Peoria, Illinois. I also hold a Juris Doctor from Washington University School of Law in St. Louis, Missouri.

4. Q. Are you currently involved with any civic organizations?

A. Yes. I am on the Board of Directors for the Economic Alliance of Greater Baltimore and the Maryland Zoological Society (the Maryland Zoo in Baltimore). I was also appointed as the Chair of the American Heart Association's Greater Baltimore Heart Walk 2014, which will take place in Baltimore on October 11, 2014.

5. Q. Have you previously testified before the District of Columbia Public Service Commission (the "Commission")?

A. No. This is the first time I have provided testimony before this Commission.

6. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the approach of Exelon Corporation ("Exelon") to honoring past commitments made when acquiring utilities and to managing its utility company subsidiaries with respect to the following important areas: electric system reliability, supplier diversity, charitable giving and community involvement. I will also discuss how BGE, since being acquired by Exelon in 2012, has been able to benefit in these particular areas. Finally, I will reference specific commitments that Exelon is making in certain of these areas in connection with its proposed acquisition and integration of Pepco Holdings, Inc. ("PHI") and its utility company subsidiaries Potomac Electric Power Company ("Pepco"), Delmarva Power & Light Company ("Delmarva Power"), and Atlantic City Electric Company ("ACE").

7. Q. Mr. Butler, how are you qualified to testify regarding Exelon's dedication to various key initiatives and programs, both at the corporate and utility company levels?

A. I have had the distinct opportunity to serve in leadership positions at each of Exelon, ComEd and now BGE. This background gives me a unique perspective on how Exelon runs its programs at the corporate level, and how it integrates and then supports the operations and goals of its utility companies. Perhaps most importantly, as the CEO of BGE, I am able to discuss how the employees and customers of a utility company that recently merged with Exelon have benefitted from the resources and opportunities available as the result of being part of the Exelon family of companies.

II. HONORING COMMITMENTS

8. Q. Mr. Butler, please explain Exelon's general approach to honoring commitments it makes in merger transactions.

A. Certainly. Exelon carefully tracks its merger commitments and ensures that it follows through on all commitments made as part of any merger transaction. I can testify from personal experience that Exelon honors the merger commitments it makes to utilities, their employees, customers and regulators.

When Exelon merged with Constellation and its subsidiary companies in 2012, it made a variety of commitments that encompassed employment level protections; preservation of employee compensation and benefits; contributions to a customer investment fund; ring-fencing requirements; maintenance of local presence; support for supplier diversity initiatives; and a concrete, long-term funding commitment for local charitable and community involvement efforts. I am happy to report that Exelon has followed through on these commitments and continues to do so.

9. Q. Will Exelon similarly honor all commitments made regarding PHI and its utility company subsidiaries, including Pepco?

A. Yes. I realize that there may be some apprehension associated with the merger of Exelon and PHI and its three utility company subsidiaries, which is normal in the face of change. As an individual who worked for Exelon when it was in the process of merging with BGE, and then who subsequently went to work for BGE as a Senior Vice President and now as CEO, I can assure all stakeholders that Exelon is a company that honors its commitments to its utility operating subsidiaries. The Exelon approach described by Mr. Crane and Mr. O'Brien of providing all necessary resources and support to Exelon utilities while also allowing those utilities to manage their business and maintain their local identity and ties to the communities and customers they serve has been clearly demonstrated throughout the fulfillment of Exelon's commitments with respect to BGE, and I expect nothing less in terms of Exelon's commitments with respect to Pepco.

III. DEDICATION TO ENHANCING ELECTRIC SYSTEM RELIABILITY

10. Q. Mr. Butler, please discuss Exelon's dedication to enhancing the electric system reliability of its subsidiary utility companies.

A. Exelon strives to enhance the electric system reliability of its utility company subsidiaries. This is accomplished through ensuring that appropriate resources and personnel work at all levels to keep the lights on, and that whenever possible, all of the Exelon utilities share best practices to promote the safe, efficient and reliable delivery of utility service to customers in the communities Exelon serves. The results have been improved reliability at all of the Exelon utilities, as discussed in the direct testimony of Mr. Alden.

11. Q. Since merging with Exelon in 2012, has BGE's electric system reliability improved?

A. Yes. BGE has seen significant improvements in its reliability metrics since becoming part of the Exelon family of utilities. In 2013, the first full year following the Exelon-Constellation transaction, BGE achieved the best reliability performance – both in fewer outages and shorter outage duration – in its history.

Among other things, BGE reduced the average time to restore service to BGE customers by almost 32%. BGE customer satisfaction scores also improved following BGE's acquisition by Exelon, as Mr. Alden explains.

12. Q. Has BGE demonstrated enhanced storm response capabilities at BGE since it became part of the Exelon family of companies?

A. Yes. As a result of the 2012 merger, BGE now has access to many additional Exelon resources to assist BGE crews in restoring power during a storm or other emergency event. For instance, during the devastating June 2012 Derecho storm, many PECO Energy Company ("PECO") crews were quickly dispatched to the BGE service territory to assist BGE personnel in restoring power. In advance of the arrival of Hurricane Sandy, BGE was able to call on ComEd crews to travel from Illinois to Maryland to assist BGE personnel in restoring power. Being able to rely on the additional resources from affiliated Exelon utility companies during storm events has been of great benefit to BGE and its customers.

13. Q. Earlier you mentioned the sharing of best practices to enhance electric service reliability. Could you provide an example of an Exelon best practices that BGE adopted?

A. Certainly. After the 2012 merger, BGE began utilizing ComEd and PECO's practice of establishing and tracking daily metrics to ensure the timely repair of system equipment. In addition, operational personnel from around the company hold a conference call every weekday morning to review system performance and any operational events from the past 24 hours to determine – in real time – any steps that may be necessary to improve service. Breaking down and reviewing performance in 24-hour increments is a best practice that yields important customer benefits. Mr. O'Brien describes other best practices that ComEd and PECO shared with BGE which have substantially enhanced reliability for our customers.

14. Q. Mr. Butler, do you believe that with respect to electric service reliability, Pepco will benefit from joining Exelon?

A. I certainly do. For instance, upon consummation of the merger, Pepco will be an Exelon utility company with service territories geographically contiguous or close to the service territories of two other Exelon utilities, BGE and PECO. This proximity will allow BGE and PECO crews to quickly respond to events in Pepco's service territory, assisting crews in safely and expeditiously restoring power. I know that Pepco has been working in recent years with success to enhance electric system reliability in its service territory, and Exelon will continue to support and enhance those efforts after the Merger, as reflected in the reliability commitments it is making as part of this Merger.

IV. DEDICATION TO SUPPLIER DIVERSITY

15. Q. Mr. Butler, please discuss Exelon's dedication to supplier diversity.

A. Exelon is focused on obtaining a variety of equipment, goods, supplies and services from a diverse array of vendors. To reach that goal, Exelon maintains a mature and strategically focused supplier diversity program. Exelon implements its supplier diversity strategy by increasing spending with certified Minority and

Women Business Enterprises ("MWBEs"), including professional service firms, investment banks and law firms.

Exelon's supplier diversity program is managed by its Diverse Business Empowerment Office ("DBEO"), reporting ultimately to the Executive Vice President and Chief Administrative and Diversity Officer. The DBEO, led by Emmett Vaughn, Exelon's Director of Diverse Business Empowerment, manages the four core elements of Exelon's supplier diversity program: (1) planning and tracking supplier diversity spend; (2) diverse business advocacy; (3) supplier development; and (4) managing a supplier diversity center of expertise.

Furthermore, Exelon is a long-standing member of the National Minority Supplier Development Council and holds a leadership position with the group's affiliated National Utilities Industry Group. Exelon is a past recipient of the Utility Leadership Award presented by the National Association of Regulatory Utility Commissioners' ("NARUC") Utility Access Partnership Committee – an award given annually to one utility company demonstrating national leadership and excellence in supplier diversity.

16. Q. How does the Exelon DBEO promote the supplier diversity program?

A. The DBEO supports multiple diverse business advocacy organizations of regional and national scope. These organizations facilitate conferences, meetings, and technical assistance workshops in support of developing diverse suppliers. Exelon's DBEO initiatives have been recognized for excellence and contributions to diverse supplier development by such organizations as the National Minority

Supplier Development Council and the United States Department of Commerce Minority Business Development Agency.

17. Q. Mr. Butler, what has been Exelon's recent direct support for Minority and Women Business Enterprises?

A. In 2013, Exelon's diverse supplier spend increased $155 million, or 21%, over the prior year, to approximately $906 million. Of the total spend, $714 million was with prime ("Tier 1") suppliers and $192 million was with subcontractor ("Tier 2") suppliers. Exelon's utility companies – ComEd, PECO and BGE – played a critical role in Exelon's supplier diversity strategy, collectively accounting for 64% of 2013 year-end diversity spend totals. In addition, as part of its commitment to expand opportunities for MWBEs outside of the supply chain facilitated spend, Exelon's spending with diverse professional service firms totaled nearly $82 million in 2013. This initiative is known as Exelon's "high-margin strategy" and focuses on eight categories: Advertising and Marketing, Business Consulting, Engineering and Technical Consulting, Financial Services, Human Resources Services, Information Technology Professional Services, Legal, and Banking. The high-margin strategy was undertaken because these businesses typically have higher profit margins and, therefore, have an increased capacity to contribute to community economic development.

Additionally, Exelon maintains a community and minority banking initiative. Launched in 2003, the initiative establishes credit facilities with community and minority-owned banks. Through these arrangements, Exelon and its subsidiaries get access to liquidity at competitive rates, and community banks gain experience with more complex transactions and the opportunity to strengthen their businesses by building a relationship with a Fortune 500 company. Local economies are also supported through the business the initiative brings. Exelon's community and minority banking initiative has grown from $36 million in 2003 to $123 million in 2013. In 2013, Exelon established a $123 million credit facility with 31 community and minority banks.

18. Q. Mr. Butler, what has been BGE's experience with supplier diversity since merging with Exelon in 2012?

A. The experience has been very positive. As part of the Exelon family of companies, BGE maintains a robust and successful supplier diversity program. Frank Kelly, BGE's Manager of Diverse Business Empowerment, oversees BGE's efforts to grow relationships with diverse suppliers and ultimately increase BGE's spending with certified MWBEs – efforts that have proven to be successful. BGE has had particular success in encouraging prime suppliers to utilize diverse subcontractors, and has realized year-over-year gains in spending on goods and services from diverse firms. Regarding the Exelon "high-margin strategy" I described above, BGE has been a significant contributor to the overall effort, establishing financial services relationships with 32 diversity certified professional services firms, including many local firms such as The Harbor Bank of Maryland, Industrial Bank, and Brown Capital Management.

BGE's recent supplier diversity efforts stem from the February 6, 2009, Memorandum of Understanding ("MOU") BGE signed with the Maryland Public Service Commission that established a target of awarding 25 percent of BGE's total eligible annual dollar spend for contracts, subcontracts, and purchase orders for products and services with diverse suppliers by 2025. When Exelon merged with BGE, it committed to fully supporting the goals of the MOU and to using its best efforts to assist BGE in meeting BGE's obligations. Exelon has honored that commitment and today BGE continues to make progress toward meeting the goals of the MOU, awarding 16.3% of total eligible dollar spend in 2013 to diverse suppliers, an amount equal to $151 million. This represents an increase of $35 million or 30% from 2012 levels. In July 2013, with the full support of Exelon, BGE launched its own internal supplier development program known as Focus 25, which was inspired by the 2009 MOU goal of achieving 25% diverse supplier spend by 2025. The underlying purpose of the program is to provide a selected group of diversity certified suppliers with the tools and knowledge to attain their next level of growth in their business through on-going one-on-one mentorship, technical assistance workshops highlighting business development processes, safety policies, and the nuances of BGE sourcing processes. The inaugural Focus 25 participants include professional services firms that are part of the "high margin strategy" I described above.

19. Q. Mr. Butler, do you expect Exelon to continue to support the current supplier diversity efforts of Pepco following the merger with PHI?

A. Yes, I do. Exelon has a longstanding track record of fully supporting the supplier diversity efforts of its operating utility companies, including providing resources and sharing best practices, experiences and expertise. As I mentioned previously, when it merged with Constellation and BGE, Exelon committed to maintaining BGE's supplier diversity efforts. Exelon has followed through on that commitment and the result is that BGE's supplier diversity efforts have continued to grow and succeed. I understand that Pepco has a MOU with the Public Service Commission of the District of Columbia. Exelon is committed to promoting the supplier diversity efforts at Pepco, through the provision of resources and the sharing of best practices, experiences and expertise.

I know that PHI is a strong supporter of efforts to increase supplier diversity, with both total company and utility-specific diverse spend increasing in 2013. Indeed, PHI has received many accolades in the past two years for its efforts in this area, including the Minority Business News USA "101 Companies Supplier Diversity Best in Class" award and being named one of Black Enterprise Magazine's "40 Best Companies for Diversity" for Supplier Diversity, Senior Management and Board of Director Diversity. By becoming part of the Exelon family, the PHI utility companies, including Pepco, will gain the full support of Exelon and its existing utility companies to build upon what have been very successful efforts to increase supplier diversity. Personally, I look forward to seeing the benefits that will result from combining the resources and initiatives of these two ardent supporters of supplier diversity efforts.

V. DEDICATION TO COMMUNITY INITIATIVES AND CHARITABLE GIVING

20. Q. Mr. Butler, please describe Exelon's focus on community initiatives and charitable giving in the communities it serves.

A. Exelon has always been focused on supporting organizations and groups within the areas and communities its subsidiary utilities serve. Over the past five years, Exelon and its distribution companies have donated over $134 million to local charitable and civic organizations that focus their efforts in four primary areas: (1) education; (2) the environment; (3) arts and culture; and (4) neighborhood development. Exelon also provides community support through the Exelon Foundation, an independent, nonprofit philanthropic organization that is funded solely by Exelon. Since its creation at the end of 2007, the Exelon Foundation has donated nearly $13.5 million to nonprofits.

In addition to monetary support, Exelon's Corporate Citizenship program strives to improve the quality of life for the people who live and work in Exelon's utility service territories. Exelon seeks to accomplish these goals through employee volunteer activities and executive involvement on non-profit boards. Exelon's employee volunteer engagement program is called "Energy for the Community." This program is designed to help Exelon employees practice the company's community service values through volunteerism. Employees can easily find and sign up for service projects in their area of interest or near where they live. In 2013, Exelon employees devoted many hours to various projects and activities benefitting the communities Exelon serves.

Exelon also sponsors its Energy for the Community Employee Volunteer Awards program, which recognizes employees who demonstrate extraordinary dedication and commitment to community service. Winning employees receive grants that are directed to the non-profit organizations at which they volunteer. In

2013, Exelon awarded 18 grants totaling $140,000 to non-profit organizations to honor employee volunteer service. Furthermore, Exelon's Dollars for Doers program rewards dedicated employee volunteers with grants to non-profit organizations where they serve at least 25 hours per year.

21. Q. Since merging with Exelon in 2012, has BGE been supportive of community initiatives and charitable giving?

A. Yes. With Exelon's support, BGE has been a significant contributor to community initiatives and charities, including several new grant initiatives. In 2013, BGE employees, friends and family logged over 25,000 hours to more than 135 community organizations through 230 events. Each year, hundreds of BGE employees volunteer their time and/or donate to the United Way of Central Maryland as part of an annual campaign. Many employees make their financial contributions through payroll deductions. In 2013, BGE employees raised over $1 million for this cause. BGE employees also serve as board members on more than 124 local non-profit organizations.

In 2014, BGE is supporting a new event – the American Heart Association's Baltimore Heart Walk on Saturday, October 11. As I mentioned previously, I have the honor of serving as the Chairman of this year's event and, in that role, I will be bringing BGE employees together to raise funds for the event as well as reaching out to other Baltimore-area businesses for support. In subsequent years, I expect that many other worthy causes will receive support as part of a long-term commitment from BGE.

BGE has also maintained its high level of direct contributions to local organizations, with more than $3.5 million donated to 237 organizations in Central Maryland in 2013. We have also initiated new programs since merging with Exelon. For example, in 2013, BGE initiated a Green Grants Program whereby BGE provided more than $415,000 in grants to nearly 50 nonprofit organizations in support of environmental stewardship initiatives. Individual grant amounts ranged from $500 to $10,000 and were focused on the areas of conservation, energy efficiency, education, pollution prevention and community activism. Additionally, as part of an Emergency Response and Safety Grants Program started in September 2012, BGE has provided more than $670,000 in grants to 80 nonprofit organizations that support emergency response and safety efforts. Grant monies from that program are used to fund equipment, programs or services that are critical to the safety of the communities BGE serves.

22. Q. Mr. Butler, do you expect Exelon to continue supporting the community initiatives of PHI and Pepco following the Merger?

A. Absolutely. Much like the charitable giving commitment Exelon made when it merged with Constellation and BGE, Exelon and its subsidiaries have agreed to provide at least an annual average of charitable contributions and traditional local community support that exceeds the 2013 level of contributions and support of PHI and Pepco for the decade following consummation of the merger. Exelon has honored the charitable giving commitments it made as part of acquiring BGE, and I am confident that Exelon will honor its charitable commitment regarding PHI and Pepco as well.

VI. CONCLUSION

23. Q. Does this conclude your prepared direct testimony?

A. Yes, it does.